The Narragansett Electric Company

d/b/a National Grid

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Supplemental
Testimony and Schedules of:

Power Sector Transformation Panel

Book 1 of 3

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Schedule PST-1
PST Plan

Chapter 1
Introduction

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Chapter 1 - Introduction

CHAPTER ONE: OUR VISION FOR A TRANSFORMED POWER SECTOR IN RHODE ISLAND

1. INTRODUCTION

Rhode Island is striving to transform its power sector, to control long term system costs, enhance customer choice and unleash third party innovation and integrate more clean energy into the electric grid. National Grid is privileged to be part of Rhode Island's energy transformation and is pleased to submit this Vision and Implementation Plan (the Plan) in support of it.

Across the U.S. and globally, the energy landscape is changing. Energy supply is becoming more diverse and less carbon-intensive, and decentralization and digitization are accelerating, driven by advances in technology and new business models. Against this backdrop there is a real and immediate opportunity to transform the energy industry. For its part, National Grid can create a more efficient energy delivery system that meets the evolving needs of customers and nurtures a vibrant, clean, and participatory energy landscape.

National Grid is proud to fulfill a unique role in Rhode Island. Our hard-working and dedicated employees bring energy to life for customers in homes and business across the state. Given National Grid's unique position, and the ambitions of legislators, regulators, and policy makers, the time is right to roll up our sleeves and work together to build a nation-leading model for energy transformation.

2. OUR VISION

By ensuring the **resiliency, efficiency, and openness** of the electric distribution grid today and for the future, we will create a powerful platform for **empowering our customers** and **supporting the transition to an affordable, sustainable clean energy system** for Rhode Island. We will know we have achieved our vision when:

- **All customers have knowledge, choice, and control,** enabled by easy access to information, useful insights on energy options, and thriving markets for innovative new services.
- **Large scale and distributed clean energy resources are commonplace and distributed energy resources are accessible to all,** enabled by affordable distributed solar and storage, effectively and efficiently integrated into a modern electric grid.
- **Efficiency and low-carbon fuels are the affordable, everyday choice,** enabled by robust markets, third party product and service offerings, resilient infrastructure, and well-designed regulatory incentives.

3. OUR PRINCIPLES

Given the scale and pace of the transformation ahead of us, successful execution of our vision will demand a holistic, rigorous and structured response, and clarity on exactly what we are seeking to achieve. With this in mind we propose four clarifying principles that underlie our vision:

- **Empower all our customers** by ensuring choice and control over their energy services.
- Cultivate an **efficient and resilient** grid that can adapt to the evolving paradigms of two-way power flows, responsive demand, and customer participation.
- Support the state of Rhode Island in achieving its **clean energy** objectives, including an 80% reduction in greenhouse gas (GHG) emissions by 2050.
- **Maximize the effectiveness of performance incentives** in driving these important outcomes for Rhode Island and its citizens.

Each of these principles is explored more fully below:

3.1 Customer Empowerment

Customers are at the heart of National Grid's proposals for Rhode Island and our focus on empowerment reflects our commitment to meet their changing needs while recognizing the diversity of our customer base. New functionalities provided by advanced meters are designed to afford customers new levels of information and insight about their energy usage, while the future introduction of time-varying rates and the overlay of third-party applications programs are designed to allow customers to exercise new levels of control and choice. In addition to our Advanced Metering Functionality proposals, we are placing particular emphasis on our Income Eligible customers, both by using a reward program to support greater control and choice, and through a new solar program that focuses on providing Income Eligible customers with the benefits of distributed energy resources.

3.2 Resiliency and Efficiency

As we reflect on the need for resiliency and efficiency it is important to note that we are building from an already strong foundation. The Company's electric system has consistently achieved high levels of reliability in Rhode Island as a result of investments that are currently funded through base rates and the Company's Infrastructure, Safety and Reliability (ISR) plan. National Grid's proposals in this filing go a step further, anticipating and responding to the impact that decarbonization, decentralization, and digitization will have on the way in which the grid is used and the demands that are placed on it. The Company has identified crucial elements of a modern grid and has proposed investments in those areas that are foundational to ensuring continued reliability, resiliency and efficiency, and effective integration of distributed energy resources. The aim of the Company is to continue to evolve towards modern, participatory electric grid that can strategically and efficiently integrate clean energy resources, and in doing so enable Rhode Islanders to take advantage of new clean energy technologies.

3.3 Transition to a sustainable clean energy future

The Company's proposals directly seek to advance the state's ambitions to realize a cleaner, more sustainable energy future, including specifically the state's commitment to reduce carbon emissions 80% by 2050 under the Resilient Rhode Island Act (2014), the Rhode Island Zero Emission Vehicle Draft Plan (2015), and the Executive Climate Change Coordinating Council's GHG Emissions Reduction Plan (2016). The Company is proposing beneficial electrification and DER programs to leverage emerging clean energy technologies including electric vehicle service equipment, ground and air source heat pumps, distributed solar, and energy storage. These programs will generate momentum in nascent sectors, test new business models, reduce system-wide energy costs, provide customer choice, and help meet the state's emissions reduction goals.

3.4 Maximizing the effectiveness of performance incentives

While the core purpose of the electric utility (to provide safe, reliable, and affordable electricity service) has remained relatively constant over the past several decades, additional objectives related to resiliency and efficiency, customer empowerment, and sustainability will require utilities to innovate with new policies, regulations, technologies, business practices, and customer offerings. To that end, well designed performance incentives that give utilities a clear signal and economic rationale to pursue innovation can create significant new value for customers. The Company's plan describes a portfolio of performance incentive mechanisms in the areas of system efficiency, distributed energy resources and network support services, and introduces new incentives to improve the efficiency of our capital investments as part of a continuous effort to strike the appropriate balance between capital cost incentives and operations and maintenance cost incentives.

These four principles complement our core commitment to the safe, reliable, and affordable delivery of energy services. Importantly, they also align closely with the state's goals for Power Sector Transformation and, taken as a whole, reflect the changing role of the utility in the context of this transformation. As we work with policy makers, regulators, and stakeholders to refine and execute our plan, these principles also serve as useful 'guardrails' for staying on track to deliver the outcomes we seek for our customers and the state as a whole.

4. POWER SECTOR TRANSFORMATION BUILDS ON A FOUNDATION OF ENERGY INNOVATION

Rhode Island has already made great strides in combining policies and legislation—for the energy industry as a whole, and for specific sectors—with proactive, purposeful efforts to engage interested stakeholders on key regulatory issues.

Recent years have seen a surge in innovative state-level policies, such as "Energy 2035," the "Rhode Island Renewable Thermal Market Development Strategy," the "Zero Emission Vehicle Action Plan," and the "City of Providence Executive Order," which together create a new framework for transforming Rhode Island's energy landscape. This framework is unique in the country in that it addresses carbon commitments on a statewide and economy-wide basis, and is overlaid with sector-specific policies designed to ensure that the transportation and heat sectors play their part. State policy makers are demonstrating genuine commitment to a clean and sustainable future.

In support of these efforts, the Rhode Island Division of Public Utilities and Carriers (The Division), Rhode Island Public Utilities Commission (PUC), and Office of Energy Resources (OER) have worked to bring together interested parties from within and outside Rhode Island to align utility regulation with the state's clean energy objectives. This means examining and adjusting the complex regulatory and legislative frameworks that exist today in an effort to remove barriers, create clarity on desired outcomes for customers, and develop a more dynamic regulatory framework for the future. Significant progress has been made through forums such as the Energy Efficiency Resource Management Council, Distributed Generation Board, System Integration Rhode Island and proceedings such as Docket 4600.

Building from that foundation, in March 2017 Governor Gina Raimondo laid out a new challenge: to create "a more nimble electric grid that can strategically integrate clean energy resources and enable Rhode Islanders to take advantage of new clean energy technologies." The state's initiative in response to this challenge became known as Power Sector Transformation. Stakeholders to the Power Sector Transformation effort have addressed a series of questions related to utility business models, beneficial electrification, connectivity, and distribution system planning. Published in November 2017, the state's "*Rhode Island Power Sector Transformation, Phase One Report to Governor Gina M. Raimondo*" (hereafter the PST Phase One Report) sets out goals and recommended actions for consideration in 2018.

National Grid has played an important and active role in all of these efforts, and most recently has worked very closely with state agencies and other parties to inform the Power Sector Transformation process. The Company is directionally well aligned with the state on many of the recommendations arising from that work and looks forward to ongoing stakeholder participation and input to inform and support achievement of our shared power sector transformation goals.

Transforming Rhode Island's power sector is a journey that must be undertaken in a thoughtful and strategic manner. It has the potential to create significant benefits for customers but these benefits cannot be realized without thoughtful investment today. Pace and momentum will be critical to success and must be carefully balanced with the Company's responsibility to create value and manage overall cost to customers. With this in mind, the Company is pleased to present a robust and balanced Vision and Implementation Plan that represents its initial three-year plan to further power sector transformation in Rhode Island.

5. STRUCTURE OF THE PLAN

Chapter Two: Summarizes the Company's Plan and how its proposals advance the state's goals for a new electric system

Chapter Three: Proposes specific investments as part of the next phase of grid modernization in Rhode Island

Chapter Four: Sets out the Company's proposal to deploy advanced metering functionality (AMF) for customers in Rhode Island.

Chapters Five, Six, and Seven: Outline a portfolio of clean energy investments in electric transport, electric heat, and energy storage

Chapter Eight: Develops proposals for income eligible customers

Chapter Nine: Describes a new performance incentives designed to incentivize utility innovation and focus in delivering outcomes that customers' value

Chapter 10: Estimates the revenue requirement associated with proposed investments in years one, two, and three of the plan and recommends a new cost recovery mechanism, the PST Provision.

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Chapter 2 - 4600 Goals/Framework

CHAPTER TWO: ADVANCEMENT OF STATE GOALS AND BENEFIT CREATION

1. INTRODUCTION

"By ensuring the ***resiliency, efficiency, and openness*** *of the electric distribution grid today and for the future, we will create a powerful platform for* ***empowering our customers*** *and* ***supporting the transition to an affordable, sustainable clean energy system*** *for Rhode Island"*

Delivery of the Company's vision for power sector transformation in Rhode Island (set out above) will require a holistic, rigorous, and structured approach over a number of years. The Company's Plan is prioritized and sized to ensure tangible progress toward this vision, recognizing the need to accelerate value creation balanced against bill impacts for customers.

The Company's four guiding principles of customer empowerment, resiliency and efficiency, transition to a clean energy future, and effective performance incentives have informed the creation of the Plan. The April 2015 *Docket 4600 Stakeholder Working Group Process Report to the Rhode Island Public Utilities Commission*[1] (hereafter Docket 4600) has provided additional direction in the form of clear goals for the electric system in Rhode Island and a framework for evaluating the costs and benefits of proposed investments.

Consistent with *The Public Utilities Commission Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid*[2] (hereafter Docket 4600 guidance), this chapter summarizes where the Company's proposals are expected to advance the goals set out in Docket 4600 and explains how the Company has evaluated the costs and benefits of its proposals, using the framework set out in Docket 4600, along with a report by the US Department of Energy (DOE) titled *Modern Distribution Grid: A Decision Guide Volume III*[3] (hereafter DOE report). Chapters three, four, five, six and seven of the Plan provide more detail on the advancement of state goals and the evaluation of program costs and benefits.

Investments proposed in the Company's Plan build on investments funded via existing mechanisms including base rates and the infrastructure, safety, and reliability (ISR) plan. Given the scale of the transformation required and the pace of industry change, the Company proposes a new cost recovery tariff, similar to the ISR, that enables plans to be submitted by the Company annually for approval by the Commission. Chapter Ten of the Plan sets out the cost recovery mechanism and tariff. It also provides the revenue requirement for the period Sept 1 2018 to March 31 2019, and illustrative revenue requirements for the fiscal years 2020, 2021 and 2022.

[1] See Stakeholder Working Group Process Report, issued in Rhode Island Docket number 4600, April 5 2017: http://www.ripuc.org/eventsactions/docket/4600-WGReport_4-5-17.pdf
[2] See Docket 4600-A Guidance Document, October 27 2017: http://www.ripuc.org/eventsactions/docket/4600A-GuidanceDocument-Final-Clean.pdf
[3] See Modern Distribution Grid: A Decision Guide Volume III, issued by Department of Energy Office of Electricity Delivery and Energy Reliability, June 28 2017: http://doe-dspx.org/wp-content/uploads/2017/06/Modern-Distribution-Grid-Volume-III.pdf

2. Advancing Docket 4600 Goals

Docket 4600 articulates several distinct goals for the electric system in Rhode Island:

i. 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);

ii. Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;

iii. Address the challenge of climate change and other forms of pollution;

iv. 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;

v. Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;

vi. Appropriately charge customers for the cost they impose on the grid;

vii. Appropriately compensate the distribution utility for the services it provides;

viii. Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

These goals have been critical to the development of the Plan, providing a reference against which to evaluate programs individually and as a portfolio. For each proposed investment included in the Plan, the Company includes an explanation of how that investment advances, detracts from, or is neutral with respect to the achievement of the state's goals for a new electric system. Table 2-1 summarizes where the Company's proposals are expected to advance those goals.

Table 2-1: Proposals in the Plan that are expected to advance Docket 4600 goals

GOALS FOR "NEW" ELECTRIC SYSTEM	Modern Grid	AMF	Electric Transport	Electric Heat	Storage	Solar	Income Eligible
Provide reliable, safe, clean, and affordable energy	Y	Y	Y	Y	Y	Y	Y
Strengthen the Rhode Island economy	Y	Y	Y	Y	Y	Y	Neutral
Address climate change and other forms of pollution	Y	Y	Y	Y	Y	Y	Y
Prioritize and facilitate increasing customer investment in their facilities	Y	Y	Y	Y	Y	Y	Neutral
Appropriately compensate distributed energy resources	Y	Y	Y	Y	Y	Neutral	Neutral
Appropriately charge customers for the cost they impose on the grid	Y	Y	Y	Neutral	Neutral	Neutral	Y
Appropriately compensate the distribution utility	Neutral	Y	Y	Neutral	Neutral	Neutral	Neutral
Align distribution utility, customer, and policy objectives and interests	Y	Y	Y	Y	Neutral	Neutral	Y

3. Evaluating Costs and Benefits of Proposals included in the Plan

The Company's Plan proposes a broad suite of investments to respond to the impact of decentralization, decarbonization, and digitization. These investments include grid-side investments to enable distributed energy resources (DER), deployment of advanced metering functionality (AMF), beneficial electrification programs in transportation and heating, and investments in energy storage and solar. While all of these investments fall under the umbrella term "grid modernization," the differing nature of the investments warrants a different benefit-cost evaluation approach in each case.

The U.S. Department of Energy is working with state regulators, the utility industry, energy services companies and technology developers to determine the functional requirements for a modern distribution grid that are needed to enhance reliability, resiliency and operational efficiency, and integrate and utilize DER. The Modern Distribution Grid Report is a three-volume set that is intended to develop a consistent understanding of requirements to inform investments in grid modernization. Volume III of the DOE Report is a "Decision Guide" that presents considerations for the rational implementation of advanced distribution system functionality.

As discussed in the DOE report, there is an identified need for a common framework for evaluating costs and benefits associated with grid modernization investments. Developing such a framework is complex due to the various uses of these investments and the different approaches that can be taken to implementation[4].

The DOE report allocates investments in a modern grid into four categories, where each category is treated differently for purposes of evaluating benefits and costs. The DOE categories are:

> **Category 1—Traditional Utility Infrastructure Investments.** This category includes grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructure for roadwork or the like, and storm damage repairs.
> **Category 2—DER Enabling Investments.** This category includes grid expenditures that are required to maintain reliable operations in a grid with much higher levels of DER connected behind and in front of the customer meter; these expenditures may be socialized across all customers.
> **Category 3—DER Integration Investments.** This category includes grid expenditures that enable public policy objectives and/or provide incremental system and societal benefits to be paid by all customers.
> **Category 4— Self-Support or Direct Charge Investments.** This category includes expenditures that will be paid directly by customers who participate in DER programs via a self-supporting, margin-neutral, opt-in DER tariff, or as part of project-specific incremental interconnection costs, for example.

The proposed treatment of the categories is as follows:

Categories 1 and 2: ***A best-fit/least-cost assessment*** is the most practical approach to evaluating traditional utility infrastructure and core platform investments. This includes investments in:

- Planning tools and models
- Physical infrastructure (e.g., wires, transformers, switches, etc.)
- Advanced protection and controls
- Sensing and situational awareness
- Operational communications

For investments in this category, the first step is to assess the “fit” against the “need” with respect to pre-determined customer and policy objectives. This best-fit assessment is applied to grid technology solutions to narrow the potential options. Afterwards, the least-cost option can be identified through various means. Most typically, this determination is the result of a competitive procurement, although states have varying approaches to assessing least-cost, best-fit options, which may also be assessed in terms of expected cost and risk.

[4] See Modern Distribution Grid: A Decision Guide Volume III, p39, Section 3.4.1 Cost-Effectiveness Framework

Category 3: Where the benefits of DER deployment are being directly considered in the evaluation of project alternatives or other investments that integrate DERs into the power system, ***a societal benefit-cost analysis*** may be useful to evaluate the cost-effectiveness of certain grid investments in relation to the value potential from enabling customer DER integration and/or DER utilization.

Category 4: For work charged directly to customers or DER developers, there is no need to go through a benefit-cost assessment as the ***customer will determine if there are sufficient benefits*** before providing a contribution in aid of construction (CIAC) payment for the agreed work.

The DOE report was developed in collaboration with state regulators, the utility industry, energy services companies, and technology developers; National Grid support the findings of the report as it relates to evaluation of grid modernization costs and benefits.

As such, grid-side investments to enable DER (presented in Chapter 3), are recommended based on a best-fit/least-cost assessment. Proposals are presented with conceptual cost estimates; a competitive procurement process will be used to ensure that project needs are addressed at the lowest cost possible prior to commencing work.

Proposals relating to AMF deployment, beneficial electrification programs in transportation and heating, and investments in storage and solar have more quantifiable benefits that can be assessed through a detailed benefit-cost analysis. For these investments, the Company has developed a Rhode Island specific benefit-cost analysis (BCA) methodology consistent with the state's Docket 4600 guidance. Further details on the Rhode Island methodology are provided in the section that follows.

4. BENEFIT-COST ANALYSIS USED IN RHODE ISLAND

National Grid, in collaboration with KPMG LLP, and in discussion with the Rhode Island Division and Tim Woolf, developed a Rhode Island specific BCA methodology to evaluate many of the investments proposed in this Plan.

In developing the methodology, the Company took a multifaceted approach that leveraged guidance provided in the Rhode Island Docket 4600 Benefit Cost Analysis Framework, including the benefit and cost categories included in Appendix 2.1. Vetted BCA models from the Company's Massachusetts and New York operating companies were also reviewed to identify project value drivers and evaluate their relevance to the projects proposed for Rhode Island. Lastly, this approach integrates already well-established assumptions and methodologies relied on for energy efficiency program BCAs in Rhode Island. Avoided energy, capacity, RECs, and environmental compliance and externality cost values, as well as wholesale market price impact assumptions and general methodology for their application were taken from the Avoided Energy Supply Costs (AESC) in New England: 2015 Report[5]. The AESC study is

[5] The AESC 2015 Report was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators including National Grid (collectively, "program administrators"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2015 Study Group to oversee design & execution of the report

sponsored and overseen by a group of New England electric and gas utilities, other efficiency program administrators, non-utility parties, and consultants, and is used by the Company and other utilities throughout New England to evaluate energy efficiency programs.

Principles of consistency, transparency, and flexibility were applied in developing the BCA methodology. As such, benefits and costs have been calculated consistently, using the same methodologies and assumptions across all projects.

The Company tested the cost-effectiveness of each category three proposal using a societal cost test (SCT) and also has included results of a ratepayer impact measure (RIM) to present the monetary benefits to all customers relative to associated costs. In particular, the RIM calculation is of interest when evaluating the electric vehicle and electric heat proposals as the RIM captures increases in utility revenue that can ultimately reduce costs to ratepayers but that would not be reflected in a societal cost test.

BCA results, and associated benefit and cost categories and values, are presented in Chapters Four, Five, Six, Seven and Eight, for the AMF, electric transportation, electric heat, storage, and solar programs respectively.

In addition to a quantitative evaluation of benefits and costs, the Plan also includes discussion of qualitative benefits for each project—for example, to identify benefits that are difficult or impossible to quantify or monetize given currently available data and methods. For simplicity and consistency these non-quantifiable benefits have been summarized under the headings societal, economic, educational, and environmental benefit. Where relevant, the Plan also discusses benefits that fall outside the scope of the defined cost tests[6]. In the case of the proposed AMF program, the Company also identifies a number of potential synergies / coordination benefits that were considered outside the scope of this analysis at this time, but that could become relevant as AMF is deployed, stabilizes, and matures.

A note on economic development benefits: The Docket 4600 BCA framework includes consideration of economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. For the purposes of the Plan, the Company undertook an initial qualitative assessment of economic development benefits, and also worked with KPMG to undertake a relatively high-level quantification exercise. The values calculated in that analysis have not been included in the cost tests as they are large and create a "masking" effect that makes it more difficult to properly evaluate the investments on their own merits. Significantly more work would be required to more accurately model the impacts of the programs and to ensure no double counting / overlap with other cost tests. Appendix 2.2 provides an overview of the methods and assumptions used to analyze economic development and the resulting values for each program, for consideration as part of a holistic evaluation of benefits and costs.

[6] For example, an investment may result in a desirable social or economic impact that represents a net transfer within the economy and is therefore not included in the SCT.

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Chapter 3 - Modern Grid

CHAPTER THREE: INVESTMENT IN A MODERN GRID

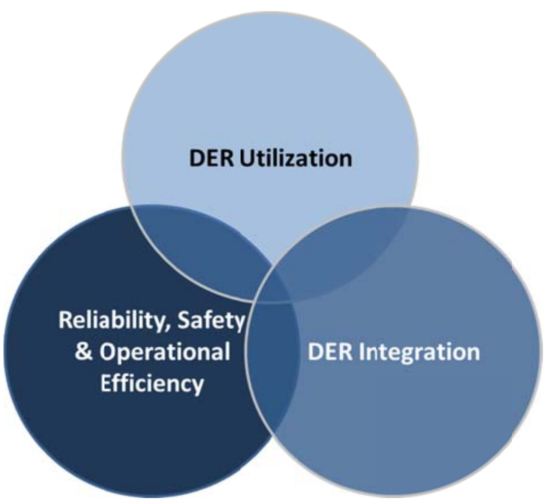
1. INTRODUCTION

The one way electric power system, designed to deliver electricity generated at large central power plants through transmission lines and distribution networks to serve customers' instantaneous energy needs at their individual premises, has served utility customers and the economy well for decades. However, advances in technology, changing customer needs, and public policy related to resource diversity, clean energy, and system efficiency are changing the way the grid is used and the demands that are placed on it.

The U.S. Department of Energy (DOE), in its recent report, *Modern Distribution Grid: A Decision Guide Volume III*[1], notes that:

> *Together, these changes are driving the need for grid modernization across three dimensions: 1) reliability, resiliency, safety and operational efficiency, 2) integration of DER, and 3) DER utilization for bulk power system and / or distribution operational services or infrastructure deferral. Investment s may be primarily associated with one of the three dimensions, but also enable functions in the other two.*

Figure 3-1: Dimensions of a Modern Grid



The concept of multiple dimensions of grid modernization is not new to Rhode Island. Through the System Integration Rhode Island (SIRI) working group and Docket 4600 "Investigation Into the Changing Distribution System", the state has clearly articulated objectives in relation to resiliency and efficiency, distributed energy resource (DER) integration, and investment deferral.

[1] U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, "Modern Distribution Grid, Decision Guide, Volume III", June 28, 2017. Available at: http://doe-dspx.org/sample-page/modern-distribution-grid-report/.

Most recently, through Power Sector Transformation, state agencies have recognized the impacts of grid modernization on both planning and operations, and have developed further principles and recommendations to guide the transition:

> *The emerging complexity of distribution grid power flows now needs real-time situational awareness to keep the lights on, increase renewable energy usage, and minimize procurement and distribution costs for ratepayers. Technologies are required that can (1) exchange information between all generating and consuming energy resources; (2) perform system-management using programmable controls; (3) integrate data from ubiquitous sensors and computer-based analytics; and (4) interface with increasingly intelligent devices within the home to help system operators manage peaks. The underlying foundation beneath all of these capabilities is network connectivity.* [2]

Grid modernization is also not new to National Grid. National Grid USA (National Grid) and its affiliates have engaged in grid modernization discussions through initiatives in both Massachusetts and New York. Our experience in those states has informed the Company's proposals for Rhode Island, and, where their goals and objectives are consistent, our proposed investments in all three jurisdictions are consistent. A coordinated deployment of certain investments in which system synergies can be achieved could produce significant cost savings for customers; thus, for the purposes of this Plan, we highlight the cost (where relevant) of making investments solely for Rhode Island, while also presenting a view that highlights potential synergies if investments are made in the Company's New York affiliate on a consistent timeframe[3]. The customer benefits that could be realized from rolling out grid modernization in more than one jurisdiction have informed our proposed cost recovery mechanism for power sector transformation.

The definition and scope of 'grid modernization' is broad and has implications for customers, DER providers, and the Company as grid owner and operator. National Grid's view of and plans for grid modernization align with the DOE Report, which was developed in collaboration with state regulators, the utility industry, energy services companies, and technology developers. The DOE report lays out the functional requirements of a modern distribution grid that are needed to enhance reliability and operational efficiency and integrate and utilize distributed energy resources, and serves as a useful reference to illustrate the Company's proposed approach to grid modernization in Rhode Island.

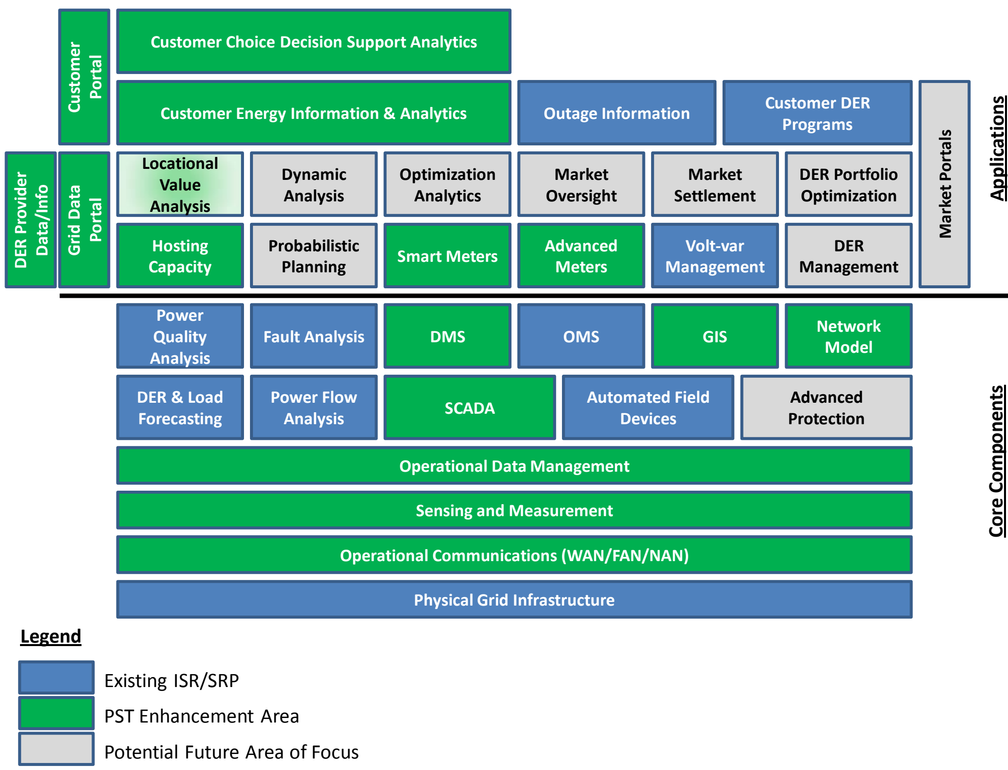
There are several functional areas in which the Company is already delivering enhanced capabilities that are featured as part of grid modernization, and a number of areas the Company proposes to move forward on as part of the plan. Figure 3-2, which is adapted from the DOE Report, is color coded to depict different phases of our proposal for grid modernization in Rhode Island. The blue elements represent areas where the Company is already implementing grid modernization investments that have previously been included in the Company's infrastructure,

[2] Rhode Island Division of Public Utilities and Carriers, "Grid Connectivity and Meter Functionality Principles and Recommendations", October 13, 2017.
[3] The Company has chosen to analyze the potential synergies of a Rhode Island / New York deployment due to the likely alignment in deployment timeframes.

safety, and reliability (ISR) annual plans. By contrast, green elements represent areas of focus for near-term activities included in this Plan and gray elements represent possible future enhancements, the timing of which will be influenced by the pace of DER integration and the development of new market-based products and services.

It is worth noting that while this color scheme helps to illustrate when new functionalities will be introduced, each functionality or application will continue to evolve over multiple years with respect to level of penetration and advanced capabilities.

Figure 3-2: Grid Modernization Project Proposals for Rhode Island



The primary focus of this Plan is on the functionalities shaded in green. However, a brief discussion regarding the on-going activities shaded in blue is also presented for completeness. The areas shaded gray describe longer-term modernization opportunities, which may warrant future action depending on the degree of DER development and the evolution of new products and services. These areas are beyond the scope of this Plan.

2. On-going Grid Modernization Activities

2.1 Physical Grid Infrastructure

The physical grid will continue to be necessary to connect customers with the cost-effective electric power they need. However, the existing grid infrastructure is aging and a well thought-out grid modernization strategy may foster the efficient implementation of new functionalities necessary to operate in environments with high penetration of DER. An integrated grid may provide the interconnections necessary for customers to enjoy reliable power, in an efficient manner, utilizing a wide range of local and remote generating sources. To the extent possible, the Company's infrastructure projects will take advantage of the latest proven technologies and will be integrated with various grid modernization elements proposed in this Plan if approved by the PUC.

2.2 Automated Field Devices

Electronic reclosers can be used to interrupt fault currents and automatically restore service after momentary outages. The Company has been deploying electronic reclosers for many years to enhance reliability. The majority of these reclosers are equipped with cellular communications that permit remote monitoring and control. In addition, the Company is now providing remote monitoring and control of "smart grid" devices (i.e., capacitor banks, voltage regulators voltage monitoring devices) through its volt-var optimization (VVO) program. VVO uses these smart grid devices, AMF (if available), and optimization software to optimally managing distribution level voltage and reactive power to reduce system losses, peak demand, and/or energy consumption. These smart grid devices are also integrated with the Company's Supervisory Control and Data Acquisition (SCADA) system for monitoring and control by system operators.

2.3 Power Flow Analysis and Fault Analysis

The Company's distribution planners utilize a number of power flow analysis software tools to perform long-term system planning, fault and protection analysis, and interconnection studies. Currently, the network models used in this suite of tools tend to be manually created for the specific individual studies they support.

2.4 DER & Load Forecasting

As part of its distribution system planning process, the Company develops a 15-year peak demand forecast. The forecast considers econometric variables that will influence load growth, as well as state policy objectives that will influence DER adoption. This load and DER forecast forms the basis of future distribution system planning capacity evaluations and associated capital investment recommendations.

2.5 Power Quality Analysis

The Company strives to continuously deliver power within defined service quality standards and to respond to identified deviations from those standards in a timely fashion. New technologies, such as intermittent DER, can create new power quality challenges, but new technologies such as power electronic voltage regulators and smart inverters also offer new tools for addressing power quality issues. The Company will continue to utilize new technologies, including those being introduced in this plan, to analyze and deliver power within service quality standards.

2.6 Outage Management System and Outage Information

The Company utilizes a state of the art outage management system (OMS) as part of its suite of tools in the operations control center. This system receives and analyzes customer interruption and trouble calls, predicts or confirms the extent of an outage, and tracks restoration efforts. In near real time, OMS information is presented for public review and query via the "Outage Central" application on the Company's website.

2.7 Volt-var Management

Enhanced volt-var optimization (VVO) benefits customers by reducing demand and energy use through conservation voltage reduction (CVR). The Company recently completed an initial VVO/CVR deployment on seven feeders in the Putnam Pike and Tower Hill areas. Results on this pilot project exceeded the anticipated 3% reduction in energy and peak demand on the targeted feeders. Customer benefits are realized through reduced commodity costs for energy and demand, which result in lower bills. Deployment on an additional 40 feeders is planned, through the Company's future ISR Plan filings, over the coming four years based on these initial positive results.

2.8 Customer DER Programs

The Company continues to screen all transmission and distribution needs to assess the feasibility of implementing non-wires alternative (NWA) solutions when the projects are initiated. When a future need is identified, the Company conducts a detailed analysis so that potential solutions (both wires and non-wires) can be conceptualized and compared. If the Company determines that a NWA solution is feasible, it is fully developed and then proposed through the system reliability procurement (SRP) report. After a NWA project is initiated DER providers are invited to propose solutions for either all or a portion of the peak MW reduction target. In the 2012 SRP Report Supplement[4], a NWA load curtailment pilot project was proposed in Tiverton and Little Compton, Rhode Island. Recently, in the 2018 SRP Report[5], the Company proposed a new NWA project called the Little Compton Battery Storage Project, which includes a 1,000kWh/250kW (continuous) battery storage system that would be installed in Little Compton for peak load relief. Both the initial pilot and the proposed project are intended to defer the $2.9 million cost of a substation upgrade. The Company will continue to analyze its current NWA screening and development processes to determine how customer DER programs might be best considered as complete or partial solutions.

[4] The Narragansett Electric Company dba National Grid, "2012 System Reliability Plan Report - Supplement", February 1, 2012. RIPUC Docket No. 4296.

[5] The Narragansett Electric Company dba National Grid, "2018 System Reliability Procurement Report", November 1, 2017. RIPUC Docket No. 4756.

3. New Grid Modernization Activities in the Plan

While the Company has taken steps towards grid modernization as discussed above, higher levels of DER penetration warrant a transformational change in grid capabilities; therefore, this Plan proposes investment in several new areas. The elements shaded green on the chart in Figure3-2 represent key grid modernization elements that comprise seven new investment areas proposed in this Plan:

1. **System Data Portal**—DER provider data/information, grid data portal, locational value analysis, hosting capacity
2. **Advanced Metering Functionality**—customer portal, customer choice decision support analytics, customer energy information and analytics, smart meters, advanced meters.
3. **Feeder Monitoring Sensors**—sensing and measurement
4. **Control Center Enhancements**—Distribution Management System, GIS, network model, SCADA
5. **Operational Data Management**
6. **Telecommunications**—operational communications
7. **Cybersecurity**

The sections that follow provide a discussion of these new investment areas. Workpapers 3.1 and 3.2 provide additional detail on the costs for each investment, both in a Rhode Island only deployment scenario and in a multi jurisdiction deployment scenario where the Company has considered the potential synergies available from deploying systems in alignment with its affiliates in New York or Massachusetts.

3.1 System Data Portal

DER providers desire access to transparent system data to facilitate the integration of DER into distribution system planning and operations. To facilitate the sharing of information with DER providers, and others, the Company is proposing to develop a system data portal and populate it with information intended to facilitate DER integration in the most advantageous locations and as cost-effectively as possible. The system data portal will be a web-based application that provides relevant distribution planning information and distribution system data that have been identified to be of interest by DER providers and other interested parties during power sector transformation stakeholder engagement and similar work in National Grid's New York jurisdiction.[6] The portal will provide access in one common location for documents such as

[6] For example, as part of their written comments to the PST Distribution System Planning work stream, the Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) stated "A well-designed data portal, developed iteratively with increasing automation, can provide a valuable conduit for information – making it available to solution providers and customers, and enabling the utility to incorporate third party solutions and customer choices into distribution system planning." and "The portal could ultimately help to accelerate collaboration between utilities and solutions providers to address areas of greatest interest and economic value." (NECEC and AEEI Letter; Re: Initial Proposals for Distribution System Planning Improvements and Request for Stakeholder Comment; September 1, 2017)

regulatory filings, load and DER forecasts, and distribution planning criteria. In addition, system data, such as circuit loading, hosting capacity analysis, and heat maps of beneficial DER locations, will be provided via interactive geographic maps. The functionality and the look and feel of the portal will be similar to a system data portal recently deployed in National Grid's New York jurisdiction. Although utilization details continue to evolve in New York, best practices and lessons learned will be used to refine efforts in Rhode Island to the furthest extent possible.

DER developers are the target audience for the system data portal. Through a series of stakeholder discussions in Rhode Island DER developers have expressed an interest in using system data to improve planning efforts associated with efficiently deploying their products and services. Moreover they have noted transparency concerning distribution system planning processes, system needs, DER opportunities, and pertinent data to inform potential interconnection requirements as key.

The need for a system data portal has been the topic of considerable stakeholder engagement within the distribution system planning working groups of the power sector transformation initiative. There is general consensus among Rhode Island stakeholders that such a portal would provide benefits and advance the objectives of integrating additional clean energy generation in a cost-effective and timely manner. DER providers have stated that information such as hosting capacity analysis facilitates the siting of new resources by identifying areas where DERs can be integrated without the need for costly system upgrades and extended interconnection timelines. Similarly, identifying areas of the grid that may become constrained in the future will help DER providers develop potential non-wires alternatives or deploy DERs that can defer distribution system upgrades if appropriately designed. This information could also be used to direct strategic electrification facilities, such as electric vehicle charging stations, to lightly loaded areas. The Company considers the system data portal to be a foundational investment for advancing Rhode Island's clean energy policies.

The content of the system data portal is expected to grow and evolve over time as new tools, data, and analysis are developed. Initially, public and other readily available data and reports will be hosted in a common location for easy web access. In concert with the creation of the portal, the Company is proposing to begin developing detailed assessments of hosting capacity and capacity constraints. The results of these assessments will be posted on the portal in the form of interactive heat maps. While striving for transparency, all data and information that are to be posted on the system data portal will be presented in a fashion that does not present physical security or cybersecurity concerns and that protects the privacy of customer information. Stakeholder engagement is essential to ensure that the system data portal is effective and the Company will continue to work with stakeholders to consider future enhancements.

<u>Project Cost Estimates</u>

Experience with developing the New York System Data Portal indicates that the labor to develop and maintain the information posted on the portal is the major cost component. The most demanding tasks involve creating hosting capacity analysis and capacity constraint heat maps. Estimates of the resources required to perform these assessments are based on similar work in progress at National Grid's New York affiliate. As this is incremental work beyond traditional distribution system planning, the Company plans to hire additional engineers and analysts to manage the portal. The anticipated additional resources include two distribution planning engineers and one analyst and represent $690,000 of the estimated increment in annual O&M costs. Software and data hosting costs for the initial functionalities of the portal are approximately $10,000 annually. To begin work on the portal as soon as possible, $80,000 has been proposed in the SRP 2018 Report. The system data portal proposal within the SRP 2018 Report reflects an initial one-year effort and only limited mapping functionality.

The estimated cash flow requirement for implementing the system data portal is presented in Table 3-1. The costs are primarily for FTEs that will be fully utilized completing RI analysis and therefore cannot be shared with other jurisdictions. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

Table 3-1: System Data Portal Cash Flow Estimate

System Data Portal Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ -	$ -	$ -	$ -
O&M	$ 0.08	$ 0.70	$ 0.70	$ 0.70	$ -
Total	$ 0.08	$ 0.70	$ 0.70	$ 0.70	$ -

3.2 Advanced Metering Functionality

Advanced metering functionality (AMF) can provide customers with enhanced understanding, choice, and control over their electricity consumption. This functionality also provides a wealth of information to support the more efficient operation of the distribution system. The modern grid functionalities that will be advanced through the Company's AMF program include customer portals, customer choice decision support analytics, customer energy information and analytics and smart meters / advanced meters. A detailed discussion of the Company's AMF program and the associated business case is provided in Chapter 4.

3.3 Feeder Monitoring Sensors

Without remote interval monitoring, loading information at substations and feeders is only captured during routine maintenance and inspection cycles, or if personnel are specifically dispatched to capture data necessary for grid operations. The dynamic impacts of DER on distribution system performance require a more granular understanding of situational awareness to assure service is maintained within acceptable service quality standards. In addition, without a granular level of monitoring at the feeder level, operators and distribution system planners have no choice but to make conservative assumptions with respect to the coincidence of load and DER generation. This can lead to restricted hosting capacity assessments and less optimal operational actions.

In recent years, sensing technology has advanced significantly. There are now several options for "clamp-on" wireless primary distribution feeder monitors for overhead circuits. The Company is considering feeder monitors that use advanced technology and avoid separate communications wiring, power supply wiring, or voltage reference cabling. These feeder monitors clamp into the primary conductors (individually) and wirelessly communicate to a control box located on a nearby pole. The sensors the Company plans to use will monitor voltage, power, and harmonic content and will be integrated with the SCADA system for immediate use in system operations. The recorded data will be stored for future distribution system planning, interconnection studies, and hosting capacity assessments.

Project Cost Estimates

The Company has been deploying remote interval monitoring and control for new substations and feeders for several years. However, its existing distribution system still has 133 feeders (35%) without interval power measurements or the ability to monitor performance remotely. Therefore, the Company proposes to install feeder monitoring sensors on approximately 26 feeders per year over the next five years at a cost of approximately $17,500 per feeder. The Company expects to begin this program in FY20 with an average capital expenditure (CAPEX) of $455,000 each year. The Company's grid monitoring objective is to have interval data at the feeder level available for all its circuits by 2024.

The estimated cash flow requirement to implement this plan for installing feeder monitoring sensors is presented in Table 3-2. Note that this is a physical infrastructure cost and cannot be shared with other jurisdictions, so cost synergies cannot be realized by coordinating across the operating companies. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

Table 3-2: Cash Flow Estimate for Feeder Monitoring Sensors Project

Feeder Monitoring Sensors Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.46	$ 0.46	$ 0.46	$ 0.46
O&M	$ -	$ -	$ 0.01	$ 0.01	$ -
Total	$ -	$ 0.46	$ 0.46	$ 0.47	$ 0.46

3.4 Control Center Enhancements

The core mission of the Company's Control Center's has been to ensure electric system reliability and safety through monitoring, operational actions, and outage response. Increasingly, distribution grid operators are playing a role in optimizing the distribution system in a more dynamic fashion, including proactive monitoring of intelligent electric devices, balancing multiple sources of load or generation, and dynamically assessing outages and restoration options to minimize customer interruption impacts. As the penetration of DERs continues to increase, DERs can be leveraged to play a more active role in managing the distribution system. However, this requires enhanced operational situational awareness to maintain reliability and safety on the distribution system. As operating the system becomes for complex, more sophisticated central management systems are needed to monitor and coordinate remote distribution automation servers/devices, communicate to the edge of the distribution grid, and collect data from grid edge devices.

The management of a more dynamic distribution system will significantly change the Company's role as operator, as depicted in the table below.

Table 3-3: The Changing Role of the Distribution Control Center

Today – Keep the Lights On	**Tomorrow – Optimize the Platform**
Paper schematic maps and manual cross-reference to GIS as needed	As-operated network model in easy-to-use geographic and schematic electronic interface
SCADA communicating to substations with no or limited quantity feeder devices	Extensive SCADA “outside the substation” for communicating with numerous feeder devices
Very limited visibility into feeder electrical state, including DER	Monitoring, state estimation, and load flow provide improved visibility, including DER
Single real power source to manage	Multiple real power sources to manage
Manually-created switch orders	Switch orders generated automatically or with assistance from ADMS
Outage prediction most often based on customer interruption calls	Outage prediction enhanced with AMF and SCADA devices
Limited historic electrical data that require significant effort to bring value	Historic data on electrical state and system configuration easily accessed by planners, engineering and design, and operations
Minimal short-term load forecasting for use in planned switching	More extensive short-term load and DER forecasting in distribution operations
Limited advanced applications to assist in maximizing performance	ADMS applications improve volt/var control, reliability, and equipment utilization
Deliver power	Enable customer electric power choices and markets

3.4.1 Distribution Supervisory Control and Data Acquisition (DSCADA)

The primary role of the DSCADA system is to collect data from intelligent electronic devices on the distribution network for use in distribution management system (DMS) simulations and optimization applications. The DSCADA system also transmits commands, settings, and other operational functions to intelligent electronic devices in the field. The DMS provides engineering-focused applications that can either assist in the operations of the distribution network, or automatically monitor and control devices on the distribution network. The Company does not currently operate a DMS.

The Company currently maintains a SCADA system that supports both transmission and distribution (T&D) monitoring and control points and an energy management system that provides network applications primarily for transmission system operations. Substation and line data are acquired from the T&D substation remote terminal units[7] (RTUs) and distribution pole-top reclosers. In addition to status, the system also provides monitoring, control, and alarming for system limits pertaining to voltage, real, and reactive power, as well as other system parameters.

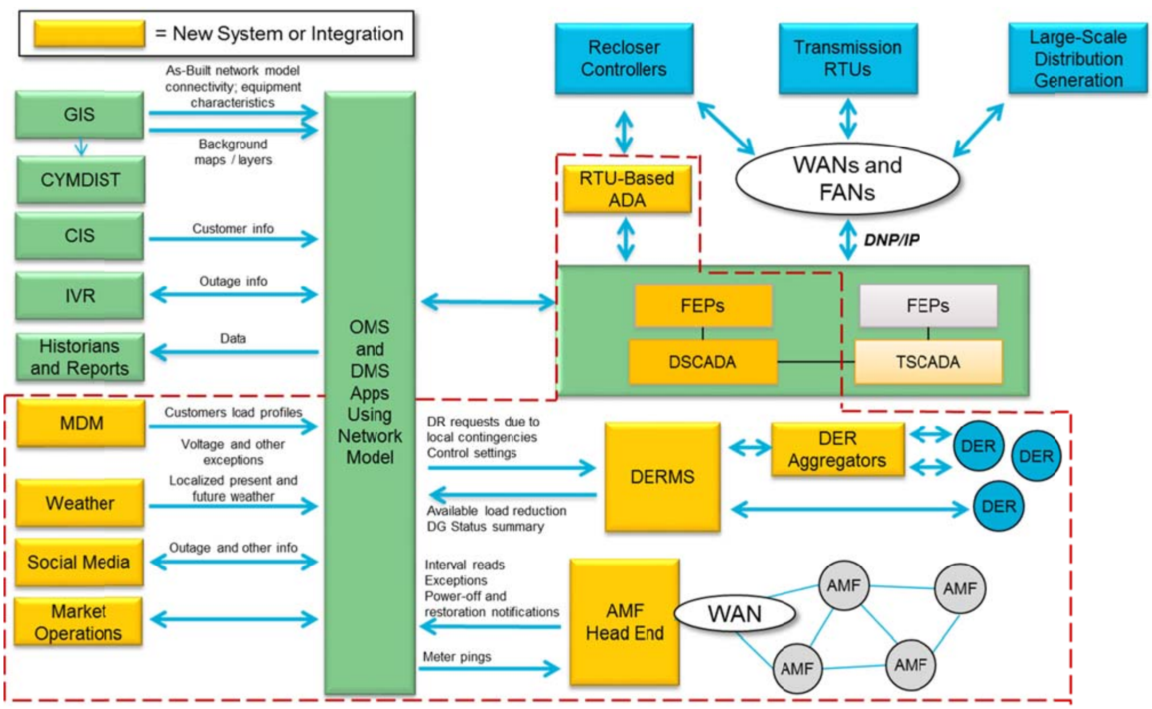
The rate at which new monitoring and control points are being added to the SCADA system is growing by more than 7% per year due to the increasing number of distribution points being created for distribution automation and the interconnection of large DER facilities. As the SCADA system approaches its capacity, the speed and performance of the system degrades. Also, combining transmission and distribution data in a common system creates data security challenges with respect to bulk transmission requirements and increases expectations for access to distribution system data.

To address these challenges, the Company and its affiliates have developed a roadmap for delivering the control center technology capabilities that will be needed in the future. The roadmap is depicted in Figure 3-3. Major changes include:

- Deployment of a new DSCADA system, created in part by separating the existing shared SCADA system into distinct transmission SCADA (TSCADA) and DSCADA systems.
- Deployment of Advanced Distribution Management System (ADMS) applications utilizing an “as-operated” distribution network model that reflects the current configuration of the distribution system.
- Retirement of legacy serial RTUs, and introduction of a third-party communication platform for distribution line recloser and SCADA exchange.

[7] Substation RTUs provide data from remote devices over fiber and phone lines to a control center for use in the SCADA system.

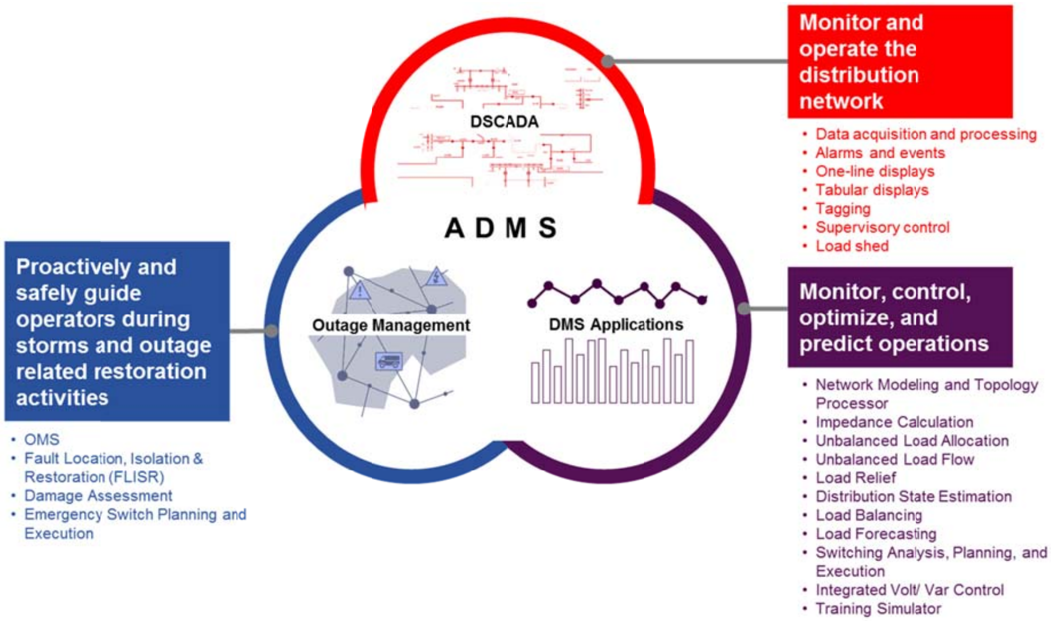
Figure 3-3: National Grid's Proposed Distribution Operations Platform



3.4.2 Advanced Distribution Management System (ADMS)

ADMS is an integrated distribution control center platform. The ADMS integrates the functionalities of the OMS, DSCADA, and DMS applications as shown in Figure 3-4. ADMS enables distribution operators to manage the modern distribution grid by providing improved visibility and control, operational flexibility, system efficiency, and automated outage response. DMS applications and DSCADA, when well-integrated with the OMS, enable operators to monitor, control, and predict operations; operate the distribution network in a more proactive fashion; and safely guide the operator's management of an increasingly complex distribution system. Specifically, an ADMS can use power flow functions considering equipment ratings, distributed generation output cycles based on fuel type, distributed energy storage charge and discharge capabilities, and existing load cycles in real time, just-in-time, or day-ahead fashion to configure the system and deploy resources as efficiently as possible. Without an ADMS, such analysis must be done using a set of static models with worst-case assumptions.

Figure 3-4: Overview of ADMS Functionality



National Grid and its affiliates operate distribution systems in multiple jurisdictions and the control center roadmap is intended to be applicable across all service territories. As such, these systems would be deployed by the National Grid USA Service Company, Inc. (the Service Company), with costs allocated to the operating companies that utilize the assets and services. The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option. Table 3-4 identifies the potential benefits of ADMS deployment.

Table 3-4: ADMS Benefits and Quantification Methodology[8]

Benefit	Quantification Methodology
Improves fault location efficiency	Reduction in field crew hours and vehicle miles traveled from more accurate fault location
Improves FLISR "self-healing" network	Avoided reliability investment cost to achieve a reduction in CMI, and assumed reduction in CMI from FLISR from peer utilities
Permits more efficient complex emergency switching	Reduction in control center operator time spent on complex switching operations
Enables VVO and CVR	Reduction in customer energy consumption at retail rate from decreased voltage at customer premise, feeder peak load reduction resulting in avoided generation capacity costs
Improves safety via equipment interrupting capability vs. available fault current	Avoided employee, contractor and public injuries and fatalities resulting in reduction of associated cost
Decreases asset maintenance costs	Elimination of annual capacitor bank inspections
Automates switching analysis	Reduction in employee time spent developing, testing, and executing orders
Increases planning efficiency	Reduction in time spent on data acquisition for distribution planners

The Company's plan is to deploy DSCADA and ADMS over a four-year horizon. In the first year, a detailed requirements definition study will be completed, followed by a three-year development and deployment schedule.

Project Cost Estimates

The DSCADA and ADMS enhancements proposed in this plan are the same in Rhode Island as they are in the Company's affiliate jurisdictions. The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option. Therefore, the Company is presenting only the multi-jurisdiction deployment scenario for this project. In the multi- jurisdiction scenario, assets and systems would be deployed by the Service Company and rental expenses would be allocated to the appropriate operating companies that benefit from these assets and systems once they are placed in service.

Multi-Jurisdiction Deployment

Estimated cash flow requirements for the Rhode Island portion of the DSCADA and ADMS implementation plan in the multi-jurisdictional scenario are presented in Table 3-5 below. In this scenario, DSCADA and ADMS deployment supports multiple operating companies and significant cost synergies can be realized because investments can be coordinated across the operating companies. As a shared system, the project would be deployed through the Service Company and placed in service in FY22, at which time an annual rental expense would be allocated to Narragansett Electric Company. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

[8] Utility results demonstrate that the line loss reduction benefit from distribution automation is minimal. Other difficult-to-quantify benefits include increased awareness of protection coordination issues, increased awareness of electrical state and device status, improved steady state / transient voltage awareness, and increased training effectiveness.

Table 3-5: DSCADA & ADMS Cash Flow Estimate – Multi-Jurisdiction Scenario

DSCADA & ADMS Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 2.52	$ 3.42	$ 1.80	$ -
O&M	$ 0.44	$ -	$ 0.09	$ 0.14	$ -
Total	$ 0.44	$ 2.52	$ 3.51	$ 1.93	$ -

As part of DSCADA deployment, a remote terminal unit (RTU) separation effort will be completed to segregate distribution data from transmission data. This is necessary to avoid North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) restrictions placed on the distribution data and control system.[9] The estimated costs of this effort are presented in Table 3.6 below. Note that costs for RTU separation cannot be shared with other jurisdictions, so cost synergies cannot be realized by coordinating across the operating companies.

Table 3-6: RTU Separation Cash Flow Estimate

RTU Separation Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.57	$ 0.95	$ 0.19	$ -
O&M	$ -	$ 0.06	$ 0.06	$ 0.06	$ -
Total	$ -	$ 0.63	$ 1.01	$ 0.25	$ -

The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

3.4.3 Geographic Information System (GIS) Data Enhancement

Modern grid operations require increasing granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality. GIS is 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. GIS information is used several ways, including for physical infrastructure project design and, through export processes, to support outage management assessments, load flow, and other analysis models. While the system and data maintained by the Company has been fit for purpose to date, the introduction of new use cases, such as for ADMS applications and hosting capacity analysis, requires change. Industry experience deploying ADMS and similar systems has shown that investment in information enhancement is needed to enable the efficient use of these advanced applications.

The Company's New York affiliate conducted an ADMS pilot on 15 circuits. The pilot showed that enhanced GIS information is necessary for successful network modelling. Lessons learned from this effort have informed the Company's development of this proposal.

[9] NERC CIP protocols require that any system that connects to transmission assets meet the same compliance standards. Without separate distribution RTUs, NERC CIP protocols require the RTU and communication infrastructure be defined as a critical cyber asset for FERC compliance considerations. Any person using the data or modifying the system would require confidentiality agreements, special permissions, and training.

A project team composed of Company and contractor resources will be convened for Rhode Island. Personnel with skills in engineering, operations, data management, and information systems (IS) will work collectively to analyze data on the Company's entire distribution system consisting of over 470 distribution circuits encompassing more than 6,445 circuit miles. This team will adopt a multifaceted approach that makes use of analytical models and techniques, Company and commercial data sources, and, as required, field observation and monitoring. By leveraging these techniques, the team will develop new GIS capabilities and expand and improve the data necessary to maintain network models for advanced applications.

The project is expected to take three years to complete and will be aligned with milestones for ADMS and other grid modernization projects. Additional quality control processes will be implemented to enhance data accuracy.

Project deliverables will include the following:

System Enhancements:

- Configure and program GIS to accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics;
- Configure and program GIS to facilitate capture of greater data and modelling granularity for underground distribution networks;
- Configure and program GIS to 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.

Data Enhancements:

- Analyze and enhance existing data, including network connectivity, configuration, and attribute-level values;
- Identify and populate additional attributes and new asset types, including network connectivity, configuration, and attribute-level values;
- Ensure complete population of DER interconnections in GIS and populate customer equipment attributes;
- Analyze, enhance, and populate additional assets to further extend underground distribution network and secondary distribution models and functionality;
- Populate enhanced substation model aligned with use in operational and planning processes.

Process Review & Improvement:

- 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.

Without these enhancements a significant increase in labor will be required to create and maintain the various network models used for distribution system planning and operational models utilized in ADMS. A timely refresh of data for the ADMS models without the automation of data flows would be inefficient.

Benefits

Implementing the GIS data enhancement project will enable network models to be developed for distribution system planning. It will also ensure that new initiatives, such as hosting capacity analysis and ADMS, can be automated and refreshed more frequently to provide more timely and accurate system assessments. This project is a critical enabler of the ADMS functionalities discussed previously and needs to be well coordinated. The project consists of IS upgrades to the corporate GIS and its costs will be allocated appropriately among benefiting operating companies. Enhancements specific to the Company will be charged directly as incurred. National Grid proposes to begin implementing information system upgrades in FY19 and then begin data enhancements specific to Rhode Island in FY21. The Company proposes to present the upcoming year's project plan as part of its annual PST Plan.

Project Cost Estimates

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. For illustrative purposes the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

Rhode Island Only Deployment

Estimated costs for the Rhode Island only GIS data enhancement (IS) implementation plan are presented in Table 3-7.

Table 3-7: GIS Data Enhancement Cash Flow Estimate for IS Resources - Rhode Island Only Scenario

GIS Data Enhancement (IS) Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ -	$ -	$ -	$ -
O&M	$ 3.05	$ -	$ -	$ -	$ -
Total	$ 3.05	$ -	$ -	$ -	$ -

Multi-Jurisdiction Deployment

Estimated cash flow requirements for Rhode Island's portion of the New York-plus-Rhode Island GIS data enhancement (IS) implementation plan are presented in Table 3-8. The IS work relating to GIS supports multiple operating companies and significant cost synergies can be realized if it is coordinated across the operating companies.

Table 3-8: GIS Data Enhancement Cash Flow Estimate for IS Resources - Multi-Jurisdiction Scenario

GIS Data Enhancement (IS) Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ -	$ -	$ -	$ -
O&M	$ 0.43	$ -	$ -	$ -	$ -
Total	$ 0.43	$ -	$ -	$ -	$ -

Regardless of a Rhode Island only or multi-jurisdiction scenario, staff from National Grid's Asset Data and Analytics team, would be required to lead the data enhancement elements of this project. These costs are shown in Table 3-9.

Table 3-9: GIS Data Enhancement Cash Flow Estimate for Non-IS Resources

GIS Data Enhancement (Non-IS) Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ 1.03	$ 1.03	$ 1.03
Total	$ -	$ -	$ 1.03	$ 1.03	$ 1.03

3.5 Operational Data Management

National Grid utilizes a large number of information systems. However, these systems are currently not as integrated as necessary to support the level of connectivity espoused in the Power Sector Transformation principles. Technologies are required that can (1) exchange information between all generating and consuming energy resources, (2) perform system management using programmable controls, (3) integrate data from ubiquitous sensors and computer-based analytics, and (4) interface with increasingly intelligent devices within the home to help system operators manage peaks. The underlying foundation that supports all these capabilities is network connectivity.

The integration of DER into real-time grid operations will require significant enhancements in telecommunications and information management systems to coordinate the interaction of large volumes of interdependent devices within a complex system that must continuously remain balanced and stable. As part of this plan, the Company is proposing to develop the platform to enable an enterprise service bus architecture, a data lake, and advanced analytics capabilities to support the AMF and grid modernization elements discussed previously in this chapter. These enhancements are explained below.

3.5.1 Enterprise Service Bus (ESB)

ESB is the enterprise middleware integration platform that is required to securely move data between systems, automate and manage business processes, transfer files between entities, and enable real-time and batch integration. Many of the Company's information systems do not move data in real time, which inherently limits their capabilities. Integrating DER requires: greater reporting; predictive analytics; insights into, and management of, the distributed network; and the management of a large volume, variety, and velocity of data. In the current architecture environment, data are available through the development of batch interfaces, for use in other applications, and are not available for real-time use. The development of specific interfaces for applications is resource intensive. To address these challenges and to enable the Company to deliver services in a more effective manner, the Company is moving toward a service-based IS architecture to support applications that require real-time data from disparate sources.

<u>Project Cost Estimates</u>

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

Rhode Island Only Deployment

Estimated cash flow requirements for implementing the enterprise service bus plan in Rhode Island only are presented in Table 3-10.

Table 3-10: Enterprise Service Bus Cash Flow Estimate – Rhode Island Only Scenario

Enterprise Service Bus Cash Flow, $M	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**
CAPEX	$ -	$ 5.50	$ 8.92	$ 1.49	$ -
O&M	$ -	$ 0.80	$ 1.95	$ 2.05	$ -
Total	$ -	$ 6.30	$ 10.87	$ 3.54	$ -

Multi-Jurisdiction Deployment

Estimated cash flow requirements for Rhode Island's portion of a coordinated enterprise service bus implementation plan for New York plus Rhode Island are presented in Table 3-11. The plan supports multiple operating companies and significant cost synergies can be realized if implementation costs are leveraged amongst the operating companies.

Table 3-11: Enterprise Service Bus Cash Flow Estimate – Multi-Jurisdiction Scenario

Enterprise Service Bus Cash Flow, $M	**FY19**	**FY20**	**FY21**	**FY22**	**FY23**
CAPEX	$ -	$ 2.06	$ 3.77	$ 0.37	$ -
O&M	$ -	$ 0.27	$ 0.62	$ 0.78	$ -
Total	$ -	$ 2.34	$ 4.39	$ 1.15	$ -

3.5.2 Data Management and Analytics

Systems are needed to store, share, and analyze the large volumes of operational data associated with a modern grid. The Company is proposing investment in three areas, internally referred to as PI Historian (a system for collecting large volumes of data), data lake (a system for storing and retrieving large volumes of data) and advanced analytics.

PI Historian records hundreds of thousands of pieces of raw operational data generated via SCADA systems, with the majority of data being recorded every few seconds. Given the large number of intelligent electronic devices being monitored and controlled in a modernized grid, the historian's capacity and capabilities need to be expanded.

PI Historian will link with a data lake where select data sets will be maintained for use by other applications. Utilizing a data lake rather than developing multiple data links directly with PI Historian will ensure that the proper data are made available for analytics and that these data are properly controlled. In addition to SCADA data, numerous other data sets will be maintained in the data lake to facilitate advanced analytics.

The advanced analytics required to efficiently manage a modern grid require processing massive quantities of data from countless data sources. The Company's compute and storage strategy is based on a hybrid sourcing vision. Currently, the Service Company contracts with an external service provider for computation and data storage, and utilizes various cloud providers for agility and cost efficiency, where appropriate.

Benefits of cloud computing include:

- Reduced time to provide needed computing resources through administered governance;
- Quicker delivery of applications and business capabilities;
- Ability to dynamically scale/flex computing resources to meet business demand; and
- Ability to provide infrastructure at competitive costs.

<u>Project Cost Estimates</u>

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

Rhode Island Only Deployment

Estimated cash flow requirements to implement data lakes, PI Historian, and advanced analytics implementation plan for Rhode Island only are presented in Tables 3-12, 3-13, and 3-14.

Table 3-12: Data Lakes Cash Flow Estimate – Rhode Island Only Scenario

Data Lake Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 1.39	$ -	$ -	$ -
O&M	$ -	$ 0.84	$ 1.21	$ 1.64	$ 1.73
Total	$ -	$ 2.24	$ 1.21	$ 1.64	$ 1.73

Table 3-13: PI Historian Cash Flow Estimate – Rhode Island Only Scenario

PI Historian Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.45	$ -	$ -	$ -
O&M	$ -	$ 0.05	$ 2.05	$ 2.05	$ 0.05
Total	$ -	$ 0.50	$ 2.05	$ 2.05	$ 0.05

Table 3-14: Advanced Analytics Cash Flow Estimate – Rhode Island Only Scenario

Advanced Analytics Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 4.73	$ 5.42	$ 3.31	$ 0.62
O&M	$ -	$ 0.11	$ 1.35	$ 1.59	$ 1.95
Total	$ -	$ 4.84	$ 6.77	$ 4.90	$ 2.57

Multi-Jurisdiction Deployment

Estimated cash flow requirements for Rhode Island's portion of a data lakes, PI Historian, and advanced analytics implementation plan for New York plus Rhode Island are presented in Tables 3-15 3-16 and 3-17. Data lakes, PI Historian, and advanced analytics support multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

Table 3-15: Data Lake Cash Flow Estimate – Multi-Jurisdiction Scenario

Data Lake Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.35	$ -	$ -	$ -
O&M	$ -	$ 0.37	$ 0.60	$ 0.84	$ 0.93
Total	$ -	$ 0.72	$ 0.60	$ 0.84	$ 0.93

Table 3-16: PI Historian Cash Flow Estimate – Multi-Jurisdiction Scenario

PI Historian Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.11	$ -	$ -	$ -
O&M	$ -	$ 0.01	$ 0.52	$ 0.52	$ 0.01
Total	$ -	$ 0.13	$ 0.52	$ 0.52	$ 0.01

Table 3-17: Advanced Analytics Cash Flow Estimate – Multi-Jurisdiction Scenario

Advanced Analytics Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 3.15	$ 1.47	$ 0.94	$ 0.62
O&M	$ -	$ 0.11	$ 0.46	$ 0.52	$ 0.61
Total	$ -	$ 3.26	$ 1.93	$ 1.46	$ 1.24

3.6 Telecommunications

Communication between devices in the field and Company systems is essential to the overall success of the modern grid. There are several main drivers for the Company's telecommunications network plan:

- Provide a reliable, cost-effective, two-way communications capability to end devices including meters, grid automation controls, field sensors, substations, field force, and customer home area network (HAN) devices;
- Ensure the network meets all technical requirements for the devices and systems deployed, including availability, latency, bandwidth, security, and other factors;
- Provide operations groups with the capability to manage, maintain, and troubleshoot the communications network; and
- Enable new grid technologies as they become available.

National Grid currently utilizes a number of different communications technologies for the collection of meter and T&D system data. In addition, the Company gathers substation information through a variety of means. 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 the integrated grid envisioned in power sector transformation.

The Company anticipates using its existing private network infrastructure—both private fiber and multiprotocol label switching (MPLS) wide area network (WAN)—to support power sector transformation objectives. Currently the Company has networks in place to support corporate functions, substations RTU/SCADA, off-site data center connectivity, and Company facility interconnections.

To handle a significant increase in the amount of data traversing these networks, the Company anticipates increasing bandwidth at a number of facilities. The Company also anticipates a significant increase in metering data as a result of its proposed AMF rollout, an increase in the number and type of distribution monitoring and control devices, and increases in substation data. This will require enhancements at the Company's control center locations, data centers, and possibly other large facilities. The Company plans to design and implement bandwidth and security upgrades over a multi-year horizon.

As discussed during numerous power sector transformation meetings on the subject of connectivity, telecommunications options are evolving rapidly. National Grid currently relies on a wide array of telecommunications technologies to support its operations and is actively evaluating alternatives for asset management in this area. As it contemplates its long term options, the Company will consider the various telecommunications models discussed within the Power Sector Transformation initiative.

Project Cost Estimates

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

Rhode Island Only Deployment

Estimated cash flow requirements to implement the telecommunications plan for Rhode Island only are presented in Table 3-18.

Table 3-18: Telecommunications Cash Flow Estimate – Rhode Island Only Scenario

Telecommunications Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.30	$ 0.15	$ 0.15	$ -
O&M	$ -	$ -	$ 1.95	$ 2.93	$ 3.90
Total	$ -	$ 0.30	$ 2.10	$ 3.08	$ 3.90

Multi-Jurisdiction Deployment

Estimated cash flow requirements for Rhode Island's portion of a telecommunications implementation plan for New York and Rhode Island are presented in Table 3-19. Telecommunications supports multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

Table 3-19: Telecommunications Cash Flow Estimate – Multi-Jurisdiction Scenario

Telecommunications Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.12	$ 0.06	$ 0.06	$ -
O&M	$ -	$ -	$ 0.66	$ 0.98	$ 1.31
Total	$ -	$ 0.12	$ 0.72	$ 1.04	$ 1.31

3.7 Cybersecurity

Cybersecurity and privacy provisions are important considerations for any power sector transformation initiative because of the imperative to maintain a reliable and secure electricity and gas infrastructure and provide the protection needed to assure the confidentiality and integrity of the digital overlay. Mere compliance with cybersecurity standards will not assure security. Cybersecurity threats to critical infrastructure emanate from a wide spectrum of potential perpetrators and the cyber threat to the electric grid is real. The question at hand is when, not if, organizations will experience attempts to infiltrate critical U.S. systems and infrastructure. The threat will only grow as the industry upgrades its systems and adopts more advanced and automated technologies, and as the inevitable convergence of information and operational technologies continues.

A reliable and secure grid is necessary to safely enable both the customer-facing and grid-facing aspects of modernizing the grid, including automated demand response, providing customers with myriad options for managing their energy costs through technology-enabled programs, limiting outages with a self-healing, resilient energy network, integrating DERs, and other strategically important functions.

The Company proposes a risk-based cybersecurity framework 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 framework will:

- Put forward a set of policies and standards to ensure the Company is working toward a common set of security objectives;
- Provide architecturally secure cybersecurity and privacy services for an efficient, easy-to-use and agile way to deliver the capabilities required to manage cyber risks;
- Look to build and enhance capability by reusing existing security capabilities where possible and, where capability is absent, by investing;
- Deliver the necessary capability to protect and ensure the resiliency of critical Company systems and infrastructure; and
- Address privacy throughout the lifecycle for sensitive customer and system data, as well as information sharing practices.

As part of the framework, the Company will implement cybersecurity and privacy provisions in the form of multiple security services to support each functional area. These security services will serve as the cornerstone for any cybersecurity or privacy-related component of the overall solution. A program to provide regular privacy training and ongoing awareness of communications and activities to all workers and third parties who have access to customer information within the distributed system platform will be included.

The implementation plan calls for a phased roll out of security services, based on business priorities and appetite for cyber risk. A formal review will occur periodically to ensure that proposed cybersecurity and privacy services evolve along with ever-changing cyber threats. These threats will be monitored continuously to ensure that Company systems, customers, and information remain protected and secured.

<u>Project Cost Estimates</u>

While National Grid’s affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

Rhode Island Only Deployment

Estimated cash flow requirements to implement the cybersecurity plan for Rhode Island only are presented in Table 3.20.

Table 3-20: Cybersecurity Cash Flow Estimate – Rhode Island Only Scenario

Cybersecurity Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 13.84	$ 6.73	$ 4.43	$ 12.33
O&M	$ 0.00	$ 8.37	$ 4.22	$ 3.37	$ 3.65
Total	$ 0.00	$ 22.22	$ 10.96	$ 7.79	$ 15.98

Multi-Jurisdiction Deployment

Estimated cash flow requirements for Rhode Island's portion of a cybersecurity implementation plan for New York and Rhode Island are presented in Table 3.21. Cybersecurity supports multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

Table 3-21: Cybersecurity Cash Flow Estimate – Multi-Jurisdiction Scenario

Cybersecurity Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 3.96	$ 1.93	$ 1.28	$ 3.24
O&M	$ 0.00	$ 2.42	$ 1.24	$ 0.96	$ 1.42
Total	$ 0.00	$ 6.38	$ 3.16	$ 2.24	$ 4.66

3.8 Advancing Power Sector Transformation Goals and State Policies

The foundational and enabling grid modernization investments proposed in this plan will directly support numerous power sector transformation objectives with respect to distribution system planning and grid connectivity and advanced metering. The Company shares the state's vision for a power sector transformed by increased DER penetration and the integration of clean energy technologies. These changes will result in a more complex distribution system that must be managed in a much more dynamic fashion. The grid sensing and distribution management systems proposed in this plan are intended to ensure that the more complex system of the future can be operated more efficiently and as safely and reliably as it has in the past.

Table 3-22 explains how individual elements of grid modernization advance, detract from, or are neutral toward goals that the PUC has adopted as a guide for reviewing any proposal filed with the PUC.

Table 3-22: High level summary of alignment between grid modernization and Docket 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 grid modernization plans are foundational enablers necessary to achieve these goals. The monitoring, control, communications, and data management elements of grid modernization are necessary to effectively manage emerging multi-directional power flows in a reliable, safe, clean, and affordable manner. In addition, proposed cybersecurity elements will enable the integration of new, grid-connected devices and remote control capabilities in a reliable and secure fashion.
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.	Advances: The investments herein include new tools, processes, and analytical capabilities that will drive a more efficient grid and ensure the affordability of clean electric power. An example of a new product being developed in Rhode Island includes Utilidata's VVO/CVR technology, which has been shown to reduce consumption and peak demand in a cost-effective manner. In addition, the system data portal and other grid modernization elements will help more Rhode Island customers become both producers and consumers of energy by enabling them to invest in their own DER technologies in areas that are most cost-effective for these resources.
Address the challenge of climate change and other forms of pollution.	Advances: The proposed feeder monitoring system, ADMS, and system data portal will enable higher penetration of clean DERs into the grid, which will reduce Rhode Island's reliance on central, carbon-based generation technologies. In addition, the modern grid will be more efficient as a result of better monitoring and control of grid-side devices and as customers become more active in managing energy usage.
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	Advances: The system data portal and new information such as hosting capacity analysis will help more Rhode Island customers and local DER developers become both producers and consumers of energy by enabling them to invest in their own DER technologies in areas where these technologies are most cost effective.

recognizable net benefits.	
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	Advances: The monitoring, communications, and data management elements of grid modernization are necessary to assess the locational and temporal value DER may provide to the electric system.
Appropriately charge customers for the cost they impose on the grid.	Advances: The monitoring, communications, data management, and cybersecurity elements of grid modernization will enable new pricing and allocation mechanisms to attribute costs and benefits more equitably.
Appropriately compensate the distribution utility for the services it provides.	Neutral
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances: 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.

3.9 Conceptual Cost Estimate for Near-Term Roadmap

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario. The estimated cash flow requirements for implementing the Plan in Rhode Island only are presented in Table 3-23; the requirements for Rhode Island's portion of implementing a multi-jurisdictional Plan are presented in Table 3-24. Significant cost synergies can be realized if these investments are coordinated across the operating companies. It should be noted that the Company is presenting only the multi-jurisdiction deployment scenario for the DSCADA and ADMS project, so the multi-jurisdiction scenario costs are used in both tables below.[10]

[10] The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option.

Table 3-23: Power Sector Transformation Cash Flow Estimate – Rhode Island Only Deployment Scenario

RI Only Scenario		Capex ($m) - Cash Flow						O&M ($m) - Cash Flow						Total ($m) - Cash Flow					
Project	Op Co.	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum
System Data Portal	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.08	0.70	0.70	0.70	0.00	2.2	0.08	0.70	0.70	0.70	0.00	2.2
Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.00	0.01	0.01	0.00	0.0	0.00	0.46	0.46	0.47	0.46	1.8
Control Center Enhancements																			
DSCADA & ADMS		0.000	2.524	3.425	1.797	0.000	7.7	0.44	0.00	0.09	0.14	0.00	0.7	0.44	2.52	3.51	1.93	0.00	8.4
RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	3.05	0.00	0.00	0.00	0.00	3.0	3.05	0.00	0.00	0.00	0.00	3.0
GIS Data Enhancement (BR)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
Operational Data Management																			
Enterprise Service Bus	SvcCo	0.000	5.501	8.919	1.492	0.000	15.9	0.00	0.80	1.95	2.05	0.00	4.8	0.00	6.30	10.87	3.54	0.00	20.7
Data Lake	SvcCo	0.000	1.394	0.000	0.000	0.000	1.4	0.00	0.84	1.21	1.64	1.73	5.4	0.00	2.24	1.21	1.64	1.73	6.8
PI Historian	SvcCo	0.000	0.451	0.000	0.000	0.000	0.5	0.00	0.05	2.05	2.05	2.05	6.2	0.00	0.50	2.05	2.05	2.05	6.7
Advanced Analytics	SvcCo	0.000	4.727	5.419	3.309	0.622	14.1	0.00	0.11	1.35	1.59	1.95	5.0	0.00	4.84	6.77	4.90	2.57	19.1
Telecommunications	SvcCo	0.000	0.304	0.152	0.152	0.000	0.6	0.00	0.00	1.95	2.93	3.90	8.8	0.00	0.30	2.10	3.08	3.90	9.4
Cybersecurity	SvcCo	0.000	13.844	6.734	4.427	12.330	37.3	0.00	8.37	4.22	3.37	3.65	19.6	0.00	22.22	10.96	7.79	15.98	57.0
TOTAL		**-**	**29.8**	**26.1**	**11.8**	**13.4**	**81.1**	**3.6**	**10.9**	**14.6**	**15.6**	**14.3**	**59.0**	**3.6**	**40.7**	**40.7**	**27.4**	**27.7**	**140.0**

Table 3-24: Power Sector Transformation Cash Flow Estimate – Multi-Jurisdiction Deployment Scenario

Multiple Jurisdiction Scenario		Capex ($m) - Cash Flow						O&M ($m) - Cash Flow						Total ($m) - Cash Flow					
Project	Op Co.	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum
System Data Portal	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.08	0.70	0.70	0.70	0.00	2.2	0.08	0.70	0.70	0.70	0.00	2.2
Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.00	0.01	0.01	0.00	0.0	0.00	0.46	0.46	0.47	0.46	1.8
Control Center Enhancements																			
DSCADA & ADMS	SvcCo	0.000	2.524	3.425	1.797	0.000	7.7	0.44	0.00	0.09	0.14	0.00	0.7	0.44	2.52	3.51	1.93	0.00	8.4
RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.43	0.00	0.00	0.00	0.00	0.4	0.43	0.00	0.00	0.00	0.00	0.4
GIS Data Enhancement (BR)	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
Operational Data Management							0.0												
Enterprise Service Bus	SvcCo	0.000	2.063	3.770	0.375	0.000	6.2	0.00	0.27	0.62	0.78	0.00	1.7	0.00	2.34	4.39	1.15	0.00	7.9
Data Lake	SvcCo	0.000	0.350	0.000	0.000	0.000	0.4	0.00	0.37	0.60	0.84	0.93	2.7	0.00	0.72	0.60	0.84	0.93	3.1
PI Historian	SvcCo	0.000	0.113	0.000	0.000	0.000	0.1	0.00	0.01	0.52	0.52	0.01	1.1	0.00	0.13	0.52	0.52	0.01	1.2
Advanced Analytics	SvcCo	0.000	3.148	1.470	0.940	0.622	6.2	0.00	0.11	0.46	0.52	0.61	1.7	0.00	3.26	1.93	1.46	1.24	7.9
Telecommunications	SvcCo	0.000	0.120	0.060	0.060	0.000	0.2	0.00	0.00	0.66	0.98	1.31	3.0	0.00	0.12	0.72	1.04	1.31	3.2
Cybersecurity	SvcCo	0.000	3.958	1.926	1.275	3.243	10.4	0.00	2.42	1.24	0.96	1.42	6.0	0.00	6.38	3.16	2.24	4.66	16.4
TOTAL		**-**	**13.3**	**12.1**	**5.1**	**4.3**	**34.8**	**0.9**	**3.9**	**6.0**	**6.5**	**5.3**	**22.7**	**0.9**	**17.2**	**18.0**	**11.6**	**9.6**	**57.5**

3.10 Conclusion

The grid modernization proposals presented in this chapter are critical enablers of DER integration in a safe and reliable fashion and provide a foundation for the continued evolution of the modern grid. This implementation Plan aligns with the recommendations of National Grid affiliates in Massachusetts and New York; an implementation effort in Rhode Island that is well coordinated with implementation efforts in these jurisdictions may result in significant cost efficiencies.

Developing a modern grid will be an on-going journey. This Plan presents meaningful initial steps to transition the planning and operation of the distribution grid so that it is more proactive, dynamic, and efficient. While the Company proposes a portfolio approach to modernizing the grid and supporting systems in the coming years, the expectation is that needs and opportunities will continue to evolve, requiring additional functionalities and capabilities. New functionalities associated with probabilistic planning, numerous optimization applications, and the management of future market-based products in services may become necessary eventually but are not warranted at this time given current levels of data availability and DER penetration.

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Chapter 4 - AMF

CHAPTER 4: ADVANCED METER FUNCTIONALITY

1. OVERVIEW

Today's customers expect more from their utility. Research shows that customers not only expect the utility to provide affordable, reliable, and safe energy, but increasingly expect access to actionable information, greater choice and control over their energy use, and delivery of energy services in a simple and convenient way. The Narragansett Electric Company d/b/a National Grid (the Company) can deliver on these expectations by providing customers with insights into their consumption patterns, offering more pricing options, and facilitating the integration of smarter devices and distributed energy resources, all while maintaining affordable, safe and reliable energy service. This functionality is now possible thanks to recent advances[1] in intelligent metering solutions. The Company believes that advanced metering, when properly deployed, is foundational to its ability to meet evolving customer expectations. With this in mind the business case described in this chapter refers not to advanced metering *infrastructure*, which would imply a focus on the technology, but instead presents a vision for advanced metering *functionality* (AMF) that the Company is committed to delivering for customers in Rhode Island.

The Company proposes to deploy AMF for the benefit of its 790,721[2] residential and commercial customers in Rhode Island. Its AMF deployment program consists of four key elements:

- An integrated system of smart electric meters and natural gas encoded radio transmitters (ERTs)
- A communications network
- An IT platform to collect, monitor, manage, and process raw data into intelligent information, and to engage customers and third parties
- Project management and ongoing business operations

Advanced metering technology will deliver new functionalities and offer significant benefits for customers, for the Company in its role as grid operator, and for society. New functionalities on the customer side include:

- **Enhanced energy management capability** that allows customers to take control of their energy usage through energy efficiency, conservation, and demand response programs, along with access to smart home devices;
- **Enablement of 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;
- **Customer service enhancements** focused on Income Eligible customers, including notifications about changes to consumption patterns mid-month that give customers an opportunity to take action before the end of the billing cycle;

[1] Processing capabilities at the edge of the grid have improved significantly with technology advancement.
[2] Includes gas and electric accounts.

- **Easier move in/out process** because the Company has the ability to start and stop electric service remotely; and
- **Savings on electric vehicle charging costs** by virtue of time-varying pricing that incentivize customers to displace vehicle charging to off-peak times.

In addition to enabling new customer-side functionality, AMF also delivers benefits on the grid side. Such benefits include:

- **Volt-var optimization (VVO)** by meters acting as end-of-line sensors to improve voltage levels across the feeders, above and beyond the existing reductions that VVO technology delivers without AMF;
- **Avoided O&M costs** by reducing the need for vans and labor to read existing meters, manual meter investigations, and connects and disconnects
- **Storm outage management system improvements** using increased visibility into where outages occur to support restoration efforts and, in concert with grid modernization efforts, to enable timely notifications to customers about the status of their outage; and,
- **Revenue benefits,** including reduced thefts of service, reduced write-offs, and improved measurement accuracy.

Broader benefits of AMF include:

- **Societal benefits,** including a reduction in greenhouse gas emissions and economic development through job growth;
- **Enabling distributed energy resources (DERs)** by providing more visibility into where DERs can offer the most value to the grid;
- **Enabling future coordination opportunities** with water utilities, street light infrastructure, gas remote service shutoff valves, and residential methane detectors; and
- **Enabling innovative rate design options** that cannot be delivered by the existing metering infrastructure but when implemented will reward customers for optimizing their energy use. (The Company considers time varying rates as a critical component of a successful deployment; new rates will be proposed in the future to align with the deployment of the physical metering infrastructure).

The AMF program aligns closely with the state's goals for a modern grid as articulated in Docket 4600. Specifically, AMF empowers customers to reduce their energy consumption, creates economic development opportunities, and improves the reliability and efficiency of electric and gas delivery. Additionally, in designing the program the Company has reflected on the PST Phase One Report. Consistent with the recommendations included in that report, the Company's proposal includes:

- Exploring the opportunity to partner with other parties that could share in the cost and benefit from the access to a state-wide communications system. Such partnerships, if found to be workable, can optimize the deployment of telecoms networks across the state;
- Exploring the use of open integration standards and protocols and outsourcing key system components where it makes sense to minimize the risk of premature obsolescence and ensure maximum technology agility in the future. A good example of this is the utilization of

Software as a Service (SaaS) platforms for elements like customer engagement or meter data management systems (MDMS);
- Enabling Green Button Connect My Data functionality that will act as the platform to provide authorized third-parties access to energy use data on a near-real time basis;
- Leveraging experience and lessons learned from the Company's Smart Energy Solutions pilot in Massachusetts and Clifton Park demonstration program in New York to achieve a more aggressive deployment schedule and deliver the benefits to all customers, including Income Eligible customers, as quickly as possible.

As described in Chapter Two of this Plan, the Company has applied its Rhode Island benefit-cost methodology to provide a quantitative evaluation of AMF deployment in Rhode Island. Two scenarios were evaluated. The first considers a Rhode Island only implementation program, while the second considers a joint Rhode Island and New York Niagara Mohawk[3] implementation strategy to show potential synergies and cost savings to Rhode Island customers should AMF deployment in New York be approved by the state's Public Service Commission.

For each of the implementation scenarios, four pricing sensitivities were evaluated based on the range of time-variant pricing benefits that might be achieved depending on whether customers opt in versus opt out, and whether they achieve high versus low energy savings.[4] **The results of the BCA tests show that full deployment of AMF can achieve net positive benefit-to-cost ratios in both scenarios**. In a Rhode Island only scenario where Rhode Island customers incur 100% of the communications, back office, and implementation costs, savings from time varying rates have to be on the higher end of the spectrum to achieve a net-positive outcome.

Consistent with Docket 4600 guidance, the Company agrees that not all of the benefits delivered by these types of programs can be quantified. As such, the Company also identifies non-quantifiable benefits that should be considered as part of a comprehensive decision framework.

To strike a balance between delivering customer benefits and managing customer bill impacts, the Company proposes a four-year plan to design, procure, and deploy AMF. As described in Chapter Two the scale of investment required to deliver power sector transformation and the associated pace of technology change warrant a staged approach to project development and approval. The proposed new PST Provision for AMF, grid modernization, and other power sector transformation investments will provide increased visibility into the evolving business case for AMF and enable Commission review and approval of costs on an annual basis. In this filing, the Company is seeking approval for FY19 costs of $2 million, to undertake the next phase of design, including further exploration of partnerships, stakeholder input, and other innovative program elements, and to undertake a procurement exercise. The outcome of the design and procurement phase will determine the costs for year two of the program (to be included in the FY20 PST Plan) and beyond.

[3] The Company chose to do a joint analysis with the AMF proposal in Niagara Mohawk because of potential alignment on timelines for decision and proposed deployment. The Niagara Mohawk AMI proposal is currently being considered as part of Niagara Mohawk's April 28, 2017 rate case filing (Case Numbers 17-E-0238 and 17-G-0239).
[4] These scenarios were developed using lessons from multiple sources, including from National Grid's Smart Energy Solutions smart grid pilot in Worcester MA. More details can be found in Section B.3.3 in Appendix 1.

2. INTRODUCTION

The evolving needs of customers and the state's clean energy policy objectives are at the heart of the transforming energy landscape. Today's customers expect a more proactive, digital, and personalized relationship with their utility and Rhode Island clean energy policy objectives are in support of more information, convenience, control, and choice. The Company is actively pursuing the foundational technical infrastructure and business capabilities necessary to deliver in this changing customer landscape.

In this Plan, the Company sets out the need for a more modern, dynamic, and flexible electric and gas system, founded on affordability, reliability, and safety, and offering new forms of customer information, convenience, control, and choice. The Plan describes how advanced metering functionality provides the enabling foundational features to meet evolving customer needs and proposes to deploy AMF technology in an effort to provide a modern grid experience to the 790,721 residential and commercial electric and gas customers in Rhode Island.

In setting out its AMF proposal, the Company provides information in three places:

- This chapter (Chapter Four) summarizes the Company's AMF proposal, discusses how AMF enables the modern grid experience and advances state goals, describes how the program will be implemented, and summarizes results from the BCA;
- Appendix 4.1 provides significantly more detail on the technologies the Company is proposing to deploy and on the costs and benefits included in the BCA; and
- Appendix 4.2 provides the Company's Rhode Island AMF BCA Methodology.

2.1 Summary of the Company's AMF proposal

As it currently exists, the Company's infrastructure is limited in its ability to meet the evolving and diverse needs of customers. This is particularly true of the Company's metering infrastructure, which serves as the interface between the customer and the Company. In Rhode Island, most meters use automatic meter reading (AMR) technology. Deployed in the early 2000s, this technology sends a radio signal to a fleet of service vans as they drive by to collect monthly reads. This technology contains core features that the Company relies on for identifying customer load, billing customers appropriately based on their electricity consumption, and managing their connection to the Company's infrastructure. However, as customer expectations change, the Company will need a modern infrastructure solution to provide more granular and timely information along with improved convenience, choice, and control. AMF can deliver these features.

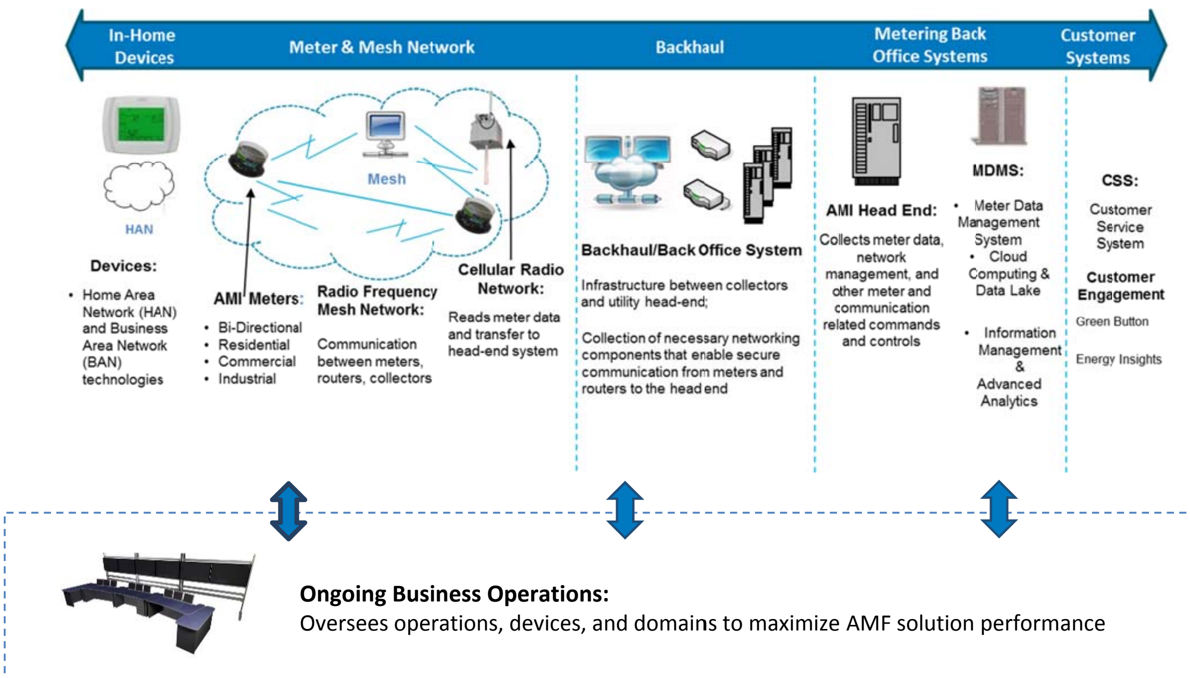
The AMF program consists of four key elements described below and illustrated in Figure 4-1.[5]

1. An integrated system of smart electric meters and natural gas ERTs that capture customer usage data and other characteristics at defined intervals;

[5] More details about the components that make up the AMF program and their costs can be found in Appendix Three.

2. A communications network for acquiring meter and field device data and enabling distribution automation (DA);
3. An IT platform for data collection, monitoring, and control of the communication system; an expanded cybersecurity system; a meter data management system (MDMS) to process meter data; an analytics platform to convert raw data into intelligent information for use in decision making by customers and the Company; customer engagement solutions; and
4. Project management and ongoing business operations.

Figure 4-1: AMF Technology Elements



2.2 Implementation Timeline

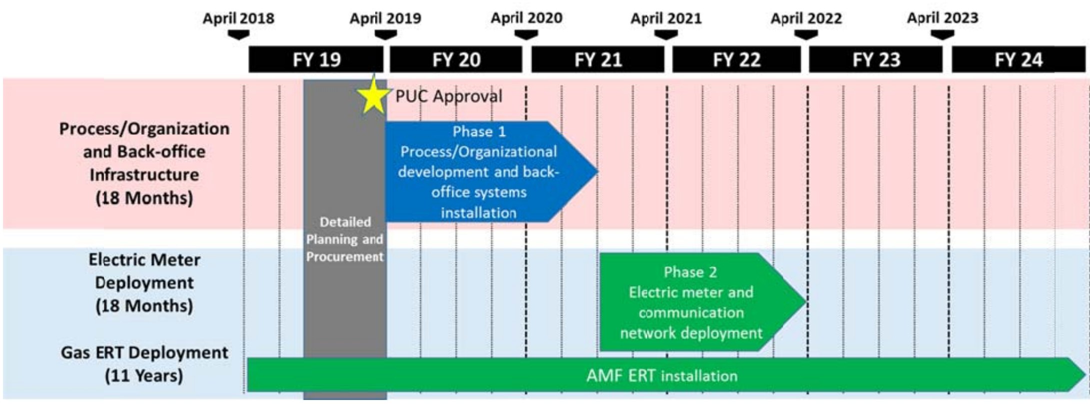
The Company proposed implementation timeline for AMF is illustrated in Figure 4-2. The timeline includes a period for detailed planning and procurement, followed by 18 months of process/organization development and back-office system installation, concluding with 18 months of meter deployment.

During the planning and procurement period, the Company will work with the Division and other interested parties to refine and update its annual AMF plans and conduct a formal design and procurement process to select software, equipment, and support vendors for the program. If the Company undertakes this phase of work in 2018, it is anticipated that the fully costed deployment proposals would be filed with the PUC in January 2019 for approval from April 1 2019.

Following approval of the deployment plan, the Company proposes a three-year timeline for AMF program implementation. Over the eighteen-month period from April 2019 through September 2020, the Company will undertake detailed process design, organizational development, and back-office systems installation. This will involve building and testing end-to-end solutions, developing procedures and training materials, organizing implementation, including training field and office personnel, developing communication materials, and initiating the customer engagement plan.

In October 2020, the Company will commence an 18-month deployment of AMF electric meters and the mesh communication network. The Company estimates that approximately 33% of electric meters will be installed in FY2021, followed by 67% in FY2022. AMF gas ERTs will be installed independent of AMF electric meters, based on the AMR ERT life-cycle replacement program which is estimated to occur over a period of 11 years.

Figure 4-2: AMF Program Deployment Schedule



2.3 Deployment of Time-Varying Rates Program

AMF technology will allow National Grid to collect utility customers' energy usage in greater detail than previous technologies will allow[6]. This time-stamped data is the foundation by which new pricing programs can be implemented. Through the provision of more granular, time-variant energy price signals, customers will have new opportunities to reduce energy consumption and/or shift usage from high cost periods to lower cost periods, while also creating system savings.

The Company plans to deploy Time Varying Rates (TVR), on an opt-out basis, to customers in conjunction with the AMF program. The Company expects that the rate may consist of two supply pricing components:

Time of Use – supply prices would vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to time of use rates,

[6] Section 4.5 provides an overview of why AMR technology is insufficient to deliver the Company's TVR program

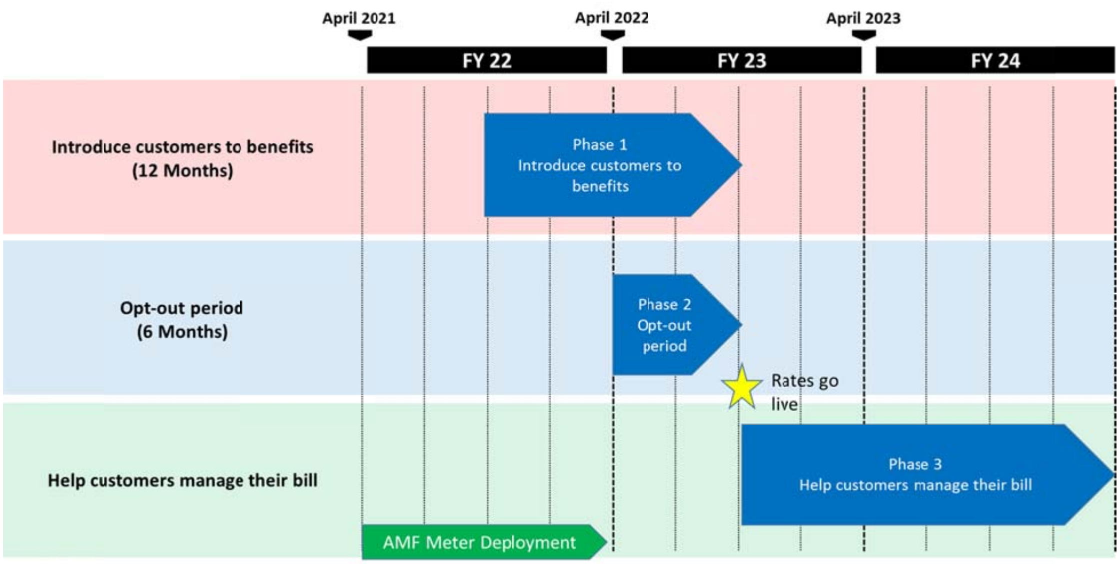
customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.

Critical Peak Pricing (CPP) – supply prices would increase further by time of day on a limited number of specific days (typically during high demands on the electrical system, where customers are notified in advance) designated as critical peak pricing events. Critical peak pricing would be designed to recover most of the costs for generation capacity in the hours that have the greatest need for peak capacity. When customers avoid consumption during the highest peak loads of the year, future generation capacity costs, as determined through ISO-NE's Forward Capacity Market auction, are reduced relative to what they otherwise might have been, resulting in capacity cost savings that are included in supply rates for customers. CPP events would be limited to a specific number of days and during specific hours of the day, which gives customers a greater level of flexibility relative to a set critical peak price period.

Based on learnings from the Smart Energy Solutions pilot in Worcester, MA, the Company understands the importance of gradual and ongoing customer outreach and education to introduce new concepts and technologies. The capabilities enabled by AMF will result in fundamental changes in customer access to energy information and their ability to control and manage energy usage. For TVR to be effective, customers must receive sufficient information to interpret and act on the new data and master the new capabilities that will be available to them. The Company proposes a three-phase rollout for the TVR program with a targeted start date of October 2021. This plan is intended to balance the need for customers to have ample time to gain understanding of their energy usage information, the structure of TVR, and their opportunities for achieving savings with the goal of ensuring that the benefits of more efficient rate design are delivered to Rhode Island customers in a timely way. Additionally, it will allow time for testing of the back office and billing processes before the rates go live.

1. Introduce customers to rate structure and benefits (Targeted October 2021 – March 2022): Through the customer engagement plan, the company will introduce the TVR rate structure and present the benefits of transitioning to these rates.
2. Opt out period (Targeted January 2022 – June 2022): The Company will give customers the opportunity to automatically transition to the TVR option or opt-out of this transition and remain on the basic rate. The transition to TVR rates will occur after this period with a targeted go-live date of July 2022.
3. Help customers manage their bills: After the transition to TVR, the Company will continue to work with customers to educate them about their bills and assist them in accessing and using the tools available to understand and control their energy use.

Figure 4-3: Targeted Time Varying Pricing program deployment schedule



The Company recognizes the critical nature of a successful rollout of TVR for customers in Rhode Island and considers this to be a major component of its AMF deployment that continues well beyond the installation of advanced meters. As such the Company proposes to work with stakeholders to optimize the design and deployment of these new rate options.

2.4 Project Costs

For purposes of this business case and the associated benefit-cost analysis, the Company has leveraged work completed to support AMF filings by its other operating companies, including cost estimates supplied by vendors, to estimate costs for AMF deployment. While National Grid's affiliates in Massachusetts and New York have proposed similar AMF programs, these plans have not yet been approved by the applicable regulatory agencies. To illustrate the potential synergies of deploying in more than one jurisdiction at the same time, the Company has evaluated two potential deployment scenarios: deployment in Rhode Island only, and deployment in Rhode Island and National Grid's upstate New York business, Niagara Mohawk. The Company chose Niagara Mohawk for this analysis because the timeline for decision and proposed deployment aligns with the proposed AMF program for Rhode Island. In the event that both programs are approved, the Company will be able to coordinate its deployment efforts across both territories.

Table 4-1 summarizes the estimated costs of the Rhode Island only scenario. Table 4-2 summarizes the estimated costs of the multi-jurisdiction scenario. Appendix 4.1 provides detailed explanations for these estimates.

Table 4-1 Estimated Costs for the Rhode Island Only Scenario ($ million)

Rhode Island Only Deployment	**Deployment Period Capital Cost**	**20 year NPV (FY20$)**
Meter Equipment and Installation	$98.47	$83.58
Communication Equipment and Installation	$4.46	$7.58
IT Platform and Ongoing IT	$88.73	$137.79
Project Management and Ongoing Business Operations	$5.70	$30.80
Total		**$259.75**

Table 4-2 Estimated Costs for the Multi-Jurisdiction Scenario ($ million)

Multi-jurisdiction Deployment	**Deployment Period Capital Cost**	**20 year NPV (FY20$)**
Meter Equipment and Installation	$97.92	$82.68
Communication Equipment and Installation	$4.12	$7.06
IT Platform and Ongoing IT	$53.15	$72.78
Project Management and Ongoing Business Operations	$4.58	$29.09
Total		**$191.61**

While these costs are presented to inform PUC evaluation of the Plan, the detailed planning and procurement phase will allow for further refinement of cost estimates for the entire AMF program and help confirm the costs to be included in the FY20 PST Plan, which will be submitted to the PUC for approval in 2019.

3. AMF ENABLES THE MODERN GRID EXPERIENCE

3.1 Diverse and Evolving Customer Expectations

Consumers are enjoying new and higher levels of service and convenience thanks to the application of advanced technology and big data across industries. Understanding how customers' diverse and evolving needs manifest in their utility experience is key to developing a more modern grid that creates sustainable value. While reliability and affordability remain the foundation of the Company's services for its customers, the Company has found through its research that it must respond to an expanding range of customer needs for visibility, control, choice, and convenience in their energy experience. According to an extensive study of customer expectations, including a survey of customers across all of National Grid USA's service territories, the modern grid experience should address several customer needs.

***Reliability*:** Fundamentally, utility customers have an expectation that their power will not go out.[7] Customer response to recent weather events in National Grid service territory and across the country indicates that the demand for a more reliable and resilient grid continues to be paramount.

***Affordability**:* When given the right tools, customers will take a more active role to minimize bill costs. For example, customers have shown a willingness to temporarily adjust their energy use in return for bill credits, as indicated by customer research,[8] smart grid pilots completed in other jurisdictions,[9] and by the more than 1,200 residential customers who are already enrolled in the Company's demand response program in Rhode Island.

Visibility: Beyond safe, affordable, and reliable power, the Company's customers want personalized, insight-based information on their usage.[10] They also expect this information to be easily accessible. More visible usage and cost information enables better energy management and helps achieve cost savings.[11]

Control: Customers want better control over how and when they use power in their homes and businesses.[12] A majority of both residential and commercial customers express interest in devices that can help them manage their energy use, such as "connected" thermostats that can be controlled remotely and that can learn a customer's habits and preferences based upon usage patterns.[13]

Choice: Greater level of choice empowers customers—from energy management to clean energy solutions to pricing. [14] Customers also want the ability to choose what communication they receive, when they receive it, and through which channels, in order to personalize their experience.

Convenience: The Company recognizes that a key aspect of customer convenience is delivering information and solutions to customers through their most preferred channels. In today's connected world, this indicates an increasing focus on web-based and mobile solutions, allowing customers to manage and optimize energy usage via an "anytime, anywhere" experience.

As customers are presented with more options, the Company will need to deliver solutions in ways that are simple for customers to understand and easy for them to adopt. While consumers express an interest in greater levels of choice, behavioral science research also suggests that overloading consumers with too many choices can result in decision inertia and less satisfaction

[7] Ninety-five percent of consumers surveyed in a national study indicated that there should be "no" or "rare" outages with the exception of storms. See Bates White Economic Consulting, *Willingness to Avoid Outages: Reliability Demand Survey*, June 2012.
[8] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.
[9] In the Smart Energy Solutions Pilot conducted in Worcester, Massachusetts, participants responded to peak events to achieve bill savings. See National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.
[10] OPower, *Five Universal Truths About Energy Consumers*, 2013.
[11] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.
[12] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.
[13] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.
[14] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

with an eventual choice.[15] Defaults can also help facilitate better customer decision making as opt-out settings increase participation levels.[16,17]

Automation provides further decision optimization by simplifying or reducing repeatable actions, such as auto-bill pay and "set and forget" features. An industry study on "the new energy consumer" showed that 60% of those surveyed would be interested in technology that could completely automate the management of their electricity use.[18] This type of automation will not be possible without smart meters and a platform that can communicate with smart devices.

3.2 Features of the Modern Customer Experience Enabled by AMF

Recognizing evolving trends in customer expectations National Grid must consider how it delivers a better experience, now and in the future. AMF enables the modern customer experience by collecting consumption data in frequent intervals and allowing customers, the Company, and third parties to access these data in near real time. This has the potential to provide significant benefits to the customer, to the grid operator, and to society. A detailed look at the proposed components and benefits of the AMF program is available in Appendix 4.1.

3.2.1 Customer Benefits

More actionable information: Through the deployment of AMF smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. As a part of the proposal, National Grid will build an energy management portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including interval data from smart meters. This will allow customers to take action to adjust their consumption patterns before the bill arrives. Customers will also receive actionable information through other channels such as text messages.

More pricing options: Smarter infrastructure coupled with an enhanced customer platform will enable the Company to offer, in the future, time-varying rates (TVR) in Rhode Island, providing customers with the opportunity to lower their electricity bills by shifting their energy usage to cheaper periods. This has the additional benefit of reducing system demand and energy costs by displacing peak period consumption for activities like electric vehicle charging. AMF will

[15] Sheena S. and Mark R. Lepper, *When Choice is Demotivating: Can One Desire Too Much of a Good Thing?* Journal of Personality and Social Psychology, 2000, Vol. 79, No. 6, pp. 995-1006.
[16] Richard H. Thaler, *Unless You Are Spock, Irrelevant Things Matter in Economic Behavior*, The New York Times (online), May 8, 2015.
[17] Opt-out default options significantly increase participation, as seen in National Grid's Smart Energy Solutions Pilot in Worcester, Massachusetts, where 95% of participating customers stayed on the default critical peak pricing rate plan and did not opt out. See Navigant, *National Grid Smart Energy Solutions Pilot Final Evaluation Report*, May 2017.
[18] Accenture, *The New Energy Consumer Architecting for the Future*, 2014.

provide more flexibility in delivering multiple rate options than current AMR meters and will avoid the costs of modifying and upgrading the existing AMR infrastructure to enable TVR[19].

Enablement of smart home devices: AMF will allow customers to manage their energy consumption through the use of smart devices such as thermostats, water heaters, and other appliances that can be integrated with AMF. Through a home area network, home energy management systems will be able to send and receive secure communications from the Company or third-party market entities. With a customer's authorization, the system can automatically adjust energy consumption in response to pricing signals and calls for curtailment.

***Access to third party services*:** Company-enabled solutions can be third-party friendly, allowing the private sector to add value above and beyond the scope of what the Company can provide. Collaboration between the Company and other partners can enable a more robust and personalized "energy journey," with bundled solutions that would not have been possible otherwise. This access will be enabled through the Green Button Connect My Data functionality and will require customer authorization.

Enhanced customer alerting and personalization tools: Customer access to timely, granular information about household energy consumption patterns is an important driver and enabler of behavioral changes and customer actions. These actions can lead to reduced consumption, increased energy affordability, and reduced bill volatility. National Grid Contact Center agents can use this data to propose company programs and offers, enabling more accurate, personalized, appropriate, and actionable offers to customers, and ultimately drive greater program uptake and improved program outcomes.

Easier move in/out process: AMF provides the ability to connect and disconnect electric service remotely and in near real time, reducing the need for manual connects and disconnects. This can improve the experience for customers when starting and stopping service.

3.2.2 Operational Benefits

Volt-var optimization: AMF meters can act as end-of-line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics.

Avoided meter investigation costs: AMF meters will reduce in-person visits by diagnosing meter related problems automatically and on demand and by allowing the Company to troubleshoot such problems remotely.

AMR meter reading: AMF meters will send data to the Company through a communications system, reducing the need for AMR meter readers, associated vehicles, and meter reading equipment maintenance.

Reduction in damage claims: AMF will allow for remote interactions that will keep metering service representatives off the road and away from customers' premises. With fewer opportunities for accidents and damage, damage claims will be reduced.

[19] More details on our review of the capabilities of AMR meters to deliver time-varying rates are available in Section 3.5

Storm outage management system improvements: AMF will increase visibility during major and minor storms by making it possible to contact meters remotely and determine outage status. Not only does this inform the Company's efforts to restore outages, but increased visibility, in concert with grid modernization efforts, can enable timely notifications to customers about the status of outages.

Avoided capital and maintenance costs of old systems: Existing systems and technology that are in use today will be phased out, avoiding expected maintenance costs.

Revenue benefits: AMF will reduce socialized costs from theft of service, write-offs due to unpaid bills, and the measurement accuracy of existing electro-mechanical meters.

3.2.3 Societal and Other Benefits

Reduction in greenhouse emissions*:* By helping customers reduce energy consumption and by improving operational efficiencies, AMF may lower emissions.

Economic development: An investment in new infrastructure may result in new jobs and create economic value for the state. Additionally, AMF may result in cost savings, efficiency improvements, and reliability and resiliency gains. By redirecting spending in other sectors of the Rhode Island economy, these investments may generate additional economic benefits.

More distributed energy resources (DER): Rapidly falling costs for solar and energy storage technologies allow customers to generate clean, low-cost energy on site. The Company must continue to enable quick and easy interconnection of these technologies using the best available information about the Company's electric system. AMF can offer more visibility into where DERs can offer the most value to the grid.

Coordination with other infrastructure: The intelligent meters and network infrastructure proposed through the AMF program may have the potential to enhance other infrastructure projects. Examples of this might include sharing networking infrastructure with water utilities, enabling improved controls and sensors for street lighting, and deploying remote gas shutoff valves and methane detectors to customers.

4. High level summary of alignment between AMF and Docket 4600 Goals

In addition to enabling a modern customer experience, Table 4-3 outlines how the AMF program may advance the state's Docket 4600 Goals.

Table 4-3: High-Level Summary of Alignment between AMF and Docket 4600 Goals

Goals for "New" Electric System	Advances? / Detracts from? / 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 – Gives customers additional tools to reduce their energy consumption and helps the utility improve its operational efficiency. Improves the visibility of DERs on the grid and offer insight into where DERs can provide the most value.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – Positively impacts GDP and tax revenue, while also creating jobs, generating labor income, and helping build a workforce with the skills and experience required to support Rhode Island's future as a clean energy economy.
Address the challenge of climate change and other forms of pollution	Advances – Gives customers additional tools to optimize their energy consumption and helps the utility improve 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	Advances – Enables time-varying rates and demand response programs, providing the customers the ability to gain value from their energy use and giving them an incentive to invest in devices that will facilitate this control.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances – Provides time and location specific information required for DER integration and valuation.
Appropriately charge customers for the cost they impose on the grid	Advances – Provides time and location specific information required for valuation.
Appropriately compensate the distribution utility for the services it provides	Advances – Provides time and location specific information required for valuation.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances – Enables new time-varying rate options for customers.

In addition to the stated goals of Docket 4600, the Division has also identified key characteristics that it would like to see in a proposed infrastructure solution. In the PST Phase One Report, the Division identified an interest in infrastructure solutions that eliminate unnecessary investment costs, avoid premature obsolescence, enable authorized third-party access to meter data, and ensure that the investment benefits all customers. This section outlines how the Company plans to address each of these interests.

4.1 Shared Infrastructure Solution

A robust telecommunications system is a foundational component for both AMF infrastructure and the Company's broader grid modernization efforts. The Company sees an opportunity in exploring partnerships with other parties that could share in the cost and benefit from the access to a statewide communications system. Examples of these potential partners include:

- **Local utilities** such as water utilities looking to use the network for their own meter communications;
- **Local agencies** interested in extending or augmenting their E911 system;
- **Municipalities** interested in advancing solutions such as intelligent lighting, warning systems, traffic monitors and environmental sensors;
- **Telecoms providers** trying to reach customers in outlying areas of the state;
- **State agencies or other entities with a mobile workforce** looking to extend or augment their land mobile radio connectivity, particularly in areas of the state where coverage is fragmented or unreliable.

To determine whether a shared network is a feasible option, the Company must first identify other parties that could benefit from the network. The Company will start this search during the design phase of the implementation plan. If the Company finds willing partners, it may then explore ways to structure a potential partnership.

While sharing a network with one or more partners may offer cost-saving opportunities, there are other regulatory, operational, and reputational considerations that should inform the decision of whether to move forward with a partnership. Cybersecurity risks in particular would have to be addressed to ensure the confidentiality of sensitive customer information.

4.2 Upgradability of Infrastructure

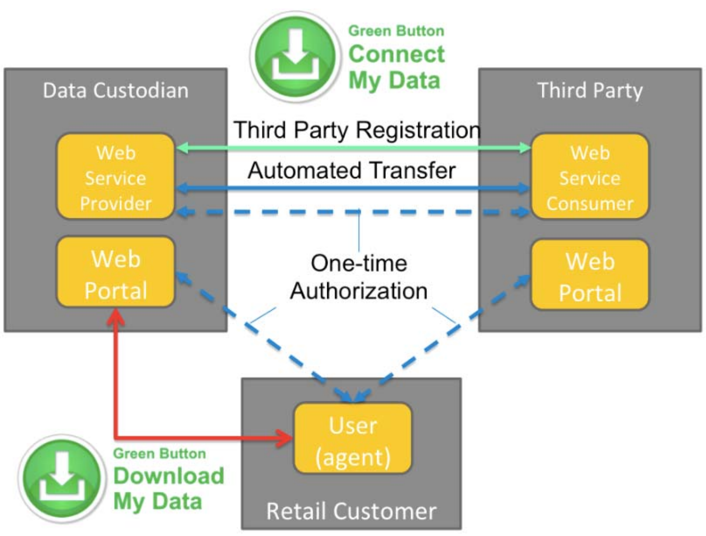
The implementation of AMF functionality introduces an increased risk of technology obsolescence. To mitigate this risk, National Grid will leverage open integration standards and protocols coupled with outsourcing of key system components to ensure maximum technology agility in the future. Vendor-hosted back-office systems coupled with third-party communication networks will provide the ability to cost-effectively adapt to new technological advances in the AMF industry. Furthermore, the metering technology will be adaptable to firmware upgrades and integration with home area network devices.

4.3 Third-Party Access

Many utilities, including National Grid, have implemented the Green Button Download My Data functionality. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third-party application.

The Green Button Connect My Data functionality takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf, as may be seen in Figure 4-3. Upon authorization, energy usage data can be transferred as required. Making these data accessible to third parties is critical to animating the market and driving innovation.

Figure 4-4: Standard communications protocol for Green Button Connect My Data



4.4 Accessibility for Income Eligible Customers

While the cost of energy service impacts all National Grid customers, this cost is a larger burden for Rhode Island's Income Eligible customers. A 2016 study from the American Council for an Energy-Efficient Economy (ACEEE) found that customers across the 48 largest metro areas in the US with a household income of $25,000 or less spend 7.2% of their income on energy utility bills.[20] Compared to the average household, which spends 3.5% of household income on energy utility bills, these Income Eligible households are disproportionately burdened. This contrast is even starker in Providence, where the same study found that customers in the Income Eligible bracket spend, on average, 9.4% of their income on utility bills.

[20] ACEEE, *Lifting the Energy Burden in America's Largest Cities*, 2016.

Based on past experience, there is evidence that Income Eligible customers are interested in, and benefit from, the cost-saving programs delivered by a smarter grid. For example, in the Smart Energy Solutions (SES) Pilot completed in Worcester, Massachusetts, 93% of participating low-income residential customers remained on the default time-varying rate (time of use with critical peak pricing) and did not opt out.[21] Evaluation of the SES Pilot found that:

- Income Eligible customers achieved savings similar to other customers in two of the three customer groups examined in the Pilot. Of the three technology/price groups examined, Income Eligible customers in two of the groups had savings that were not statistically different from the larger group.[22]
- Income Eligible customers reported having the ability to shift their energy use, according to the pre-Pilot and end-of-Pilot surveys that the Company conducted. While not measured explicitly, the Company expects that low-income customers benefited from having access to time-varying rate plans. This is because these customers are less likely to have air conditioning, which means that their load profiles are flatter than those of the average customer, resulting in comparatively lower energy usage during peak times.[23]

4.5 Alternative Metering Options for Delivering Time-Varying Rates

In an effort to deliver a modern customer experience while minimize costs, the Company has reviewed the option to deliver time-varying rates through the existing AMR meters. Through this review, the Company has found that, while delivering a basic time-varying rate option is technically feasible with AMR infrastructure, there are significant operational challenges and necessary capital upgrades that when compared to investment in AMF may make this option less beneficial to customers overall. Furthermore, relying on AMR meters limits the flexibility to make future changes or enhancements to the rate options offered to customers.

As they are currently set up, the Company's existing AMR meters cannot support time-varying pricing. In particularly, the single radio, or encoder receiver transmitter (ERT) that is used to transmit data to the Company does not have the sufficient capacity to deliver the data needed for a time-varying rate program. Typically, the single ERT meters simply 'bubble up' the register reading to capture total usage. In this way, a vehicle driving by once per month equipped to read the ERT can take monthly meter readings and send this information along to a billing engine for monthly billing.

To make time-varying rates feasible with AMR, the existing meters would have to be upgraded to a triple ERT meter. A triple ERT meter, or a meter with three radios, is traditionally used to

[21] The participation rate in time of use/critical peak pricing among non-low-income residential participants at 96% was in a similar range of that of low income participants

[22] These two groups were "Level 1 CPP Active" and "Level 1 CPP Passive". "Level 1 CPP Active" are customers who were on the Critical Peak Pricing Plan in the SES Pilot (which has on-peak and off-peak rates all of the time, and higher critical peak prices during peak events), or who had visited the Energy Management Portal for the SES Pilot and were on the default technology package for the SES Pilot. "Level 1 CPP Passive" customers were those on the time of use/critical peak pricing plan who had not visited the Energy Management Portal.

[23] The Brattle Group, *Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities*, 2015.

capture the register read for total usage, and peak demand, by collecting peak kW, peak kVA, or peak kVAR. The meter is read in the same way by a vehicle equipped to capture this data which is then sent for billing. In lieu of capturing total energy use and peak demands, three ERTs can be programmed to capture consumption over a set window. For example, one ERT would still be used to capture the register read, one could be used to capture all electricity consumed weekday peak periods, and the last one could be used to capture use on weekday off-peak periods. By using the data from all three ERTs, the Company could then calculate the use not captured in these periods.

There are a number of considerations that should be taken into account when evaluating the use of triple ERT meters as an enabler for time varying rates:

- A comparison of the costs and benefits of a triple ERT approach may provide lower net benefits to customers than the proposed AMF deployment;
- Modifying the time-varying pricing setup is challenging. If the intervals need to be modified, then the meter would need to be removed from the field and re-programmed, and then re-installed, severely limiting the ability to modify time-varying pricing windows without significant expense;
- Flexibility is limited for program expansion: The three ERT setup requires programming the meter to capture whatever intervals of time are desired, but is limited to three intervals.

A triple ERT meter is limited to a simple time of use structure, and would have none of the other attributes of an AMF system, such as remote outage notification, over the air programming to modify the parameters in the meter, and precise interval metering that can then be used with an infinite number of time of use rate structures as needed.

5. LESSONS FROM MASSACHUSETTS SUPPORT THE BUSINESS CASE IN RHODE ISLAND

5.1 Lessons from our Smart Energy Solutions Pilot in Massachusetts

The business case for an AMF program in Rhode Island is built upon knowledge gained through previous and ongoing AMF pilots across National Grid’s jurisdictions. Pilots, conducted in Worcester, Massachusetts and Clifton Park, New York, have tested, and continue to test, a number of AMF elements. In particular, lessons learned from the Company’s Massachusetts Smart Energy Solutions Pilot have enabled a more aggressive deployment schedule to be proposed, with higher certainty around expected benefits and less uncertainty around technology.

Below are several concrete examples that were tested in the Company’s Smart Energy Solutions pilot in Worcester. These examples align with Rhode Island’s goals and objectives, and are reflected in the proposal:

- Customer response to new time varying rates
- Benefits and effects of in-home technology, including an energy management portal
- Best practices for customer engagement, outreach, and education
- Benefits of information on real-time energy usage for reducing customers’ peak energy use through incentives

This two-year pilot[24] involved around 11,000 participants and provided important insights regarding customer engagement:

- An opt-out program design is a viable strategy that recruited more participants than an opt-in design would have;
- Residential customers enrolled in the default time-varying rate (time of use with critical peak pricing) achieved average per-customer bill savings of $236 over the two years of the pilot;
- Enrolled customers reduced load by 4% to 31% during times of critical peak demand;
- After two years, the pilot had a 98% customer retention rate—higher than many comparable opt-in programs;
- More than two-thirds (69%) of customers rated their satisfaction with the pilot at least a 5 on a 7-point scale;
- The availability and utilization of a customer-centric energy management portal delivered incremental benefits for customers in terms of better understanding and optimizing their energy usage, including an incremental 10% reduction in load during critical peak periods; and
- Customers want personalized information and simplified communication channels.

Beyond confirming that AMF offers customer benefits, the pilot provided information about how best to deploy AMF technology and market customer-facing programs. These results demonstrate and validate the value this kind of investment produces for customers and for the system overall.

5.2 VVO / Advanced Metering pilot for Rhode Island

The Company hopes to expand on what it has learned from its existing pilots, and to enhance the value of VVO technology, through the proposed small-scale deployment of 16,000 AMF meters filed in the Infrastructure, Safety, and Reliability Plan (ISR) earlier this year. This deployment will offer additional insight into conceptual operational benefits that have not yet been tested in any jurisdiction, identify conditions that are unique to Rhode Island that can impact widespread deployment, and help the local workforce better understand AMF technology and its implementation requirements. Several elements of the AMF program will be tested:

- **Volt-VAR Optimization**—The primary focus of this deployment is to integrate interval voltage data from advanced meters into optimization algorithms to improve system efficiency;
- **New Meter and Communications Technology—**This deployment will use the latest generation meter technology, which includes new features such as load disaggregation and locational awareness; and
- **Installation and Integration**—National Grid will have the opportunity to work with Rhode Island to deploy AMF technology on a small scale and incorporate learnings into the full deployment.

[24] The Smart Energy Solutions pilot in Worcester continues to operate In 2017 via an interim extension granted by the Massachusetts Department of Public Utilities in late 2016.

The initial deployment is proposed to be completed by FY2019. This gives the Company 18 months to integrate lessons learned into the design and operation of the full-scale AMF deployment, which is proposed to start in the second half of FY2021.

Based on projects underway across all its jurisdictions, the Company believes it is well positioned to deliver the value expected from AMF deployment, and therefore no additional demonstrations are necessary before undertaking full-scale deployment.

6. AMF PROGRAM IMPLEMENTATION

6.1 Customer Engagement (Education & Outreach)

6.1.1 Objective and Approach

The objective of the Company's customer engagement plan is to build customer awareness and interest—both in grid modernization more broadly and in the AMF technologies needed to enable grid modernization. By engaging customers proactively, the Company hopes to eliminate potential adoption barriers, encourage participation, and facilitate the transition to AMF meters.

National Grid's customer-centric customer engagement plan will be based on foundational insights and analytics gained through past efforts:

- The Company's prior experience in AMF deployment through its two Smart Energy Solutions pilots in Worcester.
- Incorporation of research, findings, and best practices from other utility AMF deployments across the country.
- The Company's vast experience and expertise in customer communication, promotion, and implementation of award-winning energy efficiency programs throughout Rhode Island.

National Grid's customer research has found that there is low familiarity with smart meters and grid modernization, but many customers are interested in learning more.[25] As mentioned in earlier sections, AMF and its enabling technologies will deliver on customers' need for information and personalized options that provide greater transparency, convenience, choice, and control. Nonetheless, the Company recognizes that communicating the spectrum of benefits achievable with advanced metering technologies may be challenging, as utilities have been historically perceived as a transactional, low-interest category. For these reasons, robust and proactive customer communications, supported by research and by a strong brand built on a foundation of trust, will be a crucial factor in successfully implementing AMF and in paving the way to other grid modernization initiatives.

The goals of the customer engagement plan are to:

- Educate customers on grid modernization offerings, including time-varying pricing, in advance of the deployment of AMF in their communities to eliminate potential adoption barriers;

[25] National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

- Build interest in and awareness of the elements of the AMF program to drive participation;
- Ensure a smooth transition process for customers; and
- Shift the focus, after an initial period of driving awareness and building interest among customers, to supporting continued customer engagement and satisfaction.

National Grid’s customer engagement strategy will be carefully planned to match the geographic deployment of AMF technologies and its communications lifecycle will be repeated in various territories until meter deployment is completed. The plan will focus on customers’ experiences and needs at different stages of the deployment process by:

- Building awareness and generating interest prior to meter installation;
- Driving participation and providing connection/transition assistance during rollout, while continuing to build interest; and
- Focusing on customer satisfaction while continuing to drive participation once meters are deployed.

The plan will be divided into three phases (pre-implementation, implementation, sustainability) and align with the areas of focus noted above.

Phase 1: Pre-Implementation

Engaging customers and stakeholders prior to the launch of a new program is considered general best practice in terms of effective outreach, engagement, and communications. National Grid will use advertising and other communications mechanisms in the months leading up to market activation and meter installations. At this stage, customers have low familiarity with AMF technology. Thus, the goal in this phase is to eliminate adoption barriers by educating customers about the benefits of grid modernization, and about the “what, why, when, and where” of grid modernization initiatives.

Steady marketing during the pre-implementation phase will be designed to build awareness and momentum by increasing the number of customers willing to learn more about grid modernization technologies and company initiatives. National Grid will leverage research, messaging strategy, and market factors to evaluate and adjust the media channel mix as needed to optimize its education and outreach efforts, while staying within the proposed budget.

Phase 2: Implementation

As meters are deployed, it will be important to engage customers through education and outreach. At this point, customer engagement activities will begin to move in parallel paths.

The Company will communicate with customers who can now take advantage of AMF on topics such as: enrollment/opt-out process, timing, installation, functionality, benefits and time-varying rates. At the same time the Company will be continuing to drive participation for customers who do not yet enjoy AMF technology.

Phase 3: Sustainability

Continued communication will help create and maintain trust and customer satisfaction, which in turn will enable deeper customer engagement. After the effort to drive awareness and build interest among customers, the customer communications strategy will shift to supporting continued customer engagement by addressing any ongoing customer issues while also promoting and sharing success stories about highly-engaged customers.

6.1.2 Supporting Communications and Tactics

Digital Channels

- Email provides a critical channel to share program information and updates, promotions, tips, success stories, and more, whether through stand-alone messages or e-newsletters.
- A dedicated and mobile-capable web page will serve as the external communications AMF landing page, with topics that include benefits, functionality, contact information, downloadable forms, and more.
- Social media platforms are an effective way to reach wide and customized audiences to share personalized content and updates, while collecting and analyzing real-time data. These platforms are also critical for social listening.

Mass Media

Radio and newspaper are cost-effective channels for reaching broad audiences within defined rollout markets, and for building frequency and message retention to:

- Increase customer familiarity with AMF, pique interest, and address adoption barriers in the months leading up to the market activation and meter installations.
- Maintain customer engagement and satisfaction after deployment and installation, and as new energy management technologies become available.

Collateral

- Bill inserts and customer newsletters featuring AMF information, tips, success stories, and more can be included in customer bills.
- Brochures can be distributed to customers and stakeholders at community events, town hall meetings and presentations, trade shows, etc.
- Direct marketing tools, such as door hangers and postcards, will be leveraged to communicate directly with customers during the transition process.

Call center support:

AMF scripts, talking points, and job aids would be available to support customer calls and to ensure call center staff alignment.

In-Person

Face-to-face engagement will offer the opportunity to educate customers on the benefits of grid modernization technologies and to answer questions, while also obtaining immediately valuable feedback and data. The Company plans to leverage various venues and activities for face-to-face engagement, including community events and town halls organized in collaboration with town and community leaders, sporting events and sponsorships, and the Rhode Island Energy Innovation Hub, among others. In-person engagement will be a critical tactic for reaching certain customer groups, including elderly and low-income customers.

6.1.3 Customer Insights

Customer insights will remain a constant component of the customer engagement process to measure the effectiveness of the Company's communications efforts and to identify changes in customer perceptions about grid modernization solutions. Periodic surveys will allow National Grid to implement a "listen, test, learn" approach, which includes listening to what customers say their needs are, using that information to test and measure different messages and communication tactics, and using the results to improve approaches along the way. Survey results will be used to understand customer awareness, sentiment, and interests so that messages and communications channels can be adjusted as needed over the course of the meter installation period and time-varying rate offerings.

Messaging studies will be conducted to test customer priorities, language effectiveness, and communications preferences in the early stages of AMF rollout. Post-rollout, it will be important to test and adjust messages as the market matures and awareness builds. Awareness studies will be conducted to track the effectiveness of National Grid's customer engagement efforts with respect to grid modernization and AMF. Satisfaction studies will be fielded after meters have been installed to assess customers' overall satisfaction with the installation process and to ask about any changes customers might have made in their energy use.

6.2 Customer Opt-Out of AMF Meters

Customers will be given sufficient advance notice, via mail, of plans to install AMF meters and of the opportunity—and procedure to be followed—to opt out of the AMF metering program if they wish. Processes and resources will be in place to support customers who are considering or have decided to opt out. Electric customers who opt out of the program will have an AMF meter installed with the communication capability deactivated. Gas customers who opt out will not have the gas ERT installed. Customers who opt out will have their meters read manually on a monthly basis and will be subject to charges per the terms and conditions specified in the Company's opt-out meter reading tariff.

6.3 Meter Deployment Planning

The Company is planning an 18-month electric meter implementation cycle beginning mid-FY2021 and ending FY2022. Actual electric meter deployment may vary from this assumption based on a number of considerations such as deployment area customer density and benefit realization. The Company plans to develop a more detailed deployment plan in FY2019. As part of National Grid's programmatic approach, the exact nature of meter deployment will need to be designed and planned to include timing of meter purchase, staging, resource scheduling, management oversight, etc.

6.4 Systems Integration Plan

System integration is key to harnessing the full magnitude of smart meter benefits across National Grid's infrastructure of devices, software, and systems. Only by enabling data exchange between meters and routers, routers and systems, and systems with other systems is it possible to maximize the effectiveness of the overall platform. As such, various costs associated with information technology and systems integration were included in the AMF business case model. A well-structured approach to systems integration will include the following:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems architecture to define data interfaces between systems and components;
- Detailed requirements definition for all systems and interfaces;
- Custom configuration and development of system application programming interfaces (APIs);
- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

AMF platforms will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an enterprise service bus (ESB), which helps facilitate the exchange of standardized data elements between all affected systems.

In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

6.5 Process Design

Engaging stakeholders within the Company to update processes is critical to successful AMF deployment. Many Company employees will be impacted by this deployment, including meter field technicians, meter shop technicians, customer service representatives, control center operators and billing analysts. Each role will be changed to some degree to accommodate the incorporation of this new technology. To aid in a smooth transition for customers and employees, defining how people will use these technologies is just as important as defining what the technologies are capable of doing. A strong process will include several elements.

Detailed Definition of System Processes and Requirements: The Company will conduct workshops with subject matter advisors, vendors, end-users, information systems and technology representatives, and other key stakeholders to gather, define, and document business processes for the new systems. These sessions, particularly the ones that address integration, will uncover additional business, functional, non-functional, performance, technical, data, integration, and transitional requirements.

Process Design and Organizational Impacts: The Company will create process flow documents to facilitate stakeholder agreement concerning key sequences, activities, and organizational divisions. The Company will refine processes by documenting requirements, inputs/outputs, contemplated customizations, organization/change impacts, key performance indicators, dependencies, business rules, data needs, data flows, reporting considerations, etc.

Cross-Workstream Integration: Teams across the business will work together to ensure shared understanding of solutions that are being designed and tested.

6.6 Vendor Selection and Management

The Company's proposed approach to the detailed design phase of its AMF program includes time to engage with vendors to explore innovative AMF solutions. This will be followed by requests for proposals and engagement in competitive and strategic negotiations with vendors to obtain the best prices and design solutions for customers. The Company's governance framework will manage and oversee the vendor selection process while considering various factors, including vendor reputation, current and future delivery costs, prior industry experience, risk mitigation, and reporting protocol.

6.7 Back-Office Upgrades and Communication Network Installation

After detailed design and procurement and prior to meter deployment, National Grid will install/upgrade the appropriate back-office systems to be able to handle incoming interval meter data. Additionally, the Company will develop procedures and training materials and ensure the relevant field and office personnel are appropriately trained.

7. Quantitative Benefit-Cost Analysis

This section discusses the results of the Company's BCA for the proposed AMF program. A detailed look at the benefit and cost assumptions used in the analysis can be found in Appendix 4.1.

7.1 Framework for the Benefit-Cost Analysis

The Company's BCA utilizes the societal cost test (SCT), which accounts for operational benefits to the Company, as well as benefits experienced by customers, reductions in resource requirements (e.g. generation capacity, energy use), and reductions in externalities such as carbon emissions. The SCT does not treat transfers between parties (such as reductions in theft of service, reductions in write-offs, and improved accuracy of electromechanical meters) as benefits or costs. As described in Chapter Two the Company utilized its Rhode Island cost-benefit methodology to quantify the benefits and costs of AMF deployment. Appendix 4.2 sets out that methodology.

Tables 4-4 and 4-5 summarize the categories of benefits and costs included in the societal cost test for this program.

Table 4-4: Benefits Included in BCA

Category	Benefit	Societal Cost Test
Avoided O&M Costs	AMR Meter Reading	X
	Meter Investigation	X
	Remote Connect and Disconnect	X
	Reduction in Damage Claims	X
	Storm OMS Benefit	X
	FCS Meter Reading	X
	Interval Meter Reading	X
Avoided AMR Costs	Capital	X
	Operations & Maintenance	X
Customer	Volt-VAR Optimization	X
	Energy Insights/High Usage Alerts	X
	Time Varying Rates	X
	Electric Vehicle Pricing	X
Societal	Reduction in Greenhouse Gas Emissions	X
Revenue	Reduction in Theft of Service	
	Reduction in Write-offs	
	Electromechanical Meter	

Table 4-5: Costs Included in BCA

Category	Cost	Societal Cost Test
Meter Equipment and Installation	Electric Meters	X
	Gas ERTs	X
	Meter and ERT Inventory	X
	Support Infrastructure	X
Communication Equipment and Installation	Network Equipment and Install	X
	Backhaul	X

Category	Cost	Societal Cost Test
IT Platform and Ongoing IT Operations	AMF Head-end and Meter Data Management Systems	X
	Customer Service System	X
	Customer Engagement Products and Services	X
	IS Infrastructure	X
	Cyber Security	X
Project Mgmt. and Ongoing Business Operations	Project Management	X
	Equipment and Installation Refresh Cost	X
	Ongoing Business Management	X
	Customer Engagement Cost	X

7.2 Discount Rates

The present value of costs and benefits are discounted back to FY2020 (when costs are first incurred) using the National Grid weighted average cost of capital ("WACC") as the discount rate. The after-tax WACC (7.51%) is used for the SCT since taxes are considered income transfers and are excluded from the societal test.

7.3 Summary of Benefits and Costs

Two scenarios were evaluated: one considers AMF implementation in Rhode Island only; the other considers a joint implementation effort that encompasses Rhode Island and the New York Niagara Mohawk service territory.[26] The latter achieves cost synergies in the IT platform and project management areas. In the multi-jurisdiction scenario, assets and systems would be deployed by the service company, and rental expenses would be allocated to the appropriate operating companies that benefit from these assets and systems once they are placed in service.

For each of the implementation scenarios, four pricing sensitivities were evaluated based on the range of time-variant pricing benefits described and included in Appendix 4.1. Results for each of the scenarios are presented in Tables 4-6 and 4-7 below.

[26] National Grid also developed a business case for an AMF program in Massachusetts, which is currently under review. If this program were to move ahead, additional synergies would further increase the Benefits/Costs ratio.

Table 4-6: Rhode Island Only Implementation Societal Test Benefits and Costs

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
Costs 20 Yr NPV *($ Million)*	Meter Equipment and Installation	$83.58	$83.58	$83.58	$83.58
	Communication Equipment and Installation	$7.58	$7.58	$7.58	$7.58
	IT Platform and Ongoing IT	$137.79	$137.79	$137.79	$137.79
	Project Management and Ongoing Business Operations	$30.80	$30.80	$30.80	$30.80
	Total Costs	$259.75	$259.75	$259.75	$259.75
Benefits 20 Yr NPV *($ Million)*	Avoided O&M Costs	$52.64	$52.64	$52.64	$52.64
	Avoided AMR Costs	$66.49	$66.49	$66.49	$66.49
	Customer	$68.99	$122.61	$87.44	$162.02
	Societal	$16.40	$35.01	$22.65	$47.50
	Total Benefits	$204.52	$276.74	$229.22	$328.65
B/C Ratio	Societal Cost Test	0.79	1.07	0.88	1.27

Table 4-7: Rhode Island and New York Joint Implementation Societal Test Benefits and Costs

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
Costs	Meter Equipment and Installation	$82.68	$82.68	$82.68	$82.68
	Communication Equipment and Installation	$7.06	$7.06	$7.06	$7.06
	IT Platform and	$72.78	$72.78	$72.78	$72.78

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
	Ongoing IT				
	Project Management and Ongoing Business Operations	$29.09	$29.09	$29.09	$29.09
	Total Costs	$191.60	$191.60	$191.60	$191.60
Benefits	Avoided O&M Costs	$52.64	$52.64	$52.64	$52.64
	Avoided AMR Costs	$66.06	$66.06	$66.06	$66.06
	Customer	$68.99	$122.61	$87.44	$162.02
	Societal	$16.40	$35.01	$22.65	$47.50
	Total Benefits	$204.09	$276.31	$228.79	$328.22
B/C Ratio	Societal Cost Test	1.07	1.44	1.19	1.71

These results demonstrate that the Rhode Island-only implementation scenario has a positive BCA ratio for the high savings TVR sensitivity cases, while the Rhode Island and New York joint implementation scenario has a positive BCA ratio across all four TVR sensitivity cases.

The results of the BCA show that full deployment of AMF can achieve a net positive benefit-to-cost ratio in both scenarios, additional qualitative benefits have also been taken into consideration. These qualitative benefits are described in Table 4-8.

Table 4.8 Qualitative Benefits of AMF Deployment

Category	Description / Examples
Societal	AMF will provide the infrastructure and capabilities necessary to enable customers to reduce overall peak demand and energy usage, thereby improving grid reliability and resiliency. Improved reliability and resiliency can reduce the risk of blackouts and sustained blackouts during peak energy demand periods and disasters. AMF will provide a necessary component that enables grid modernization and will assist with building the foundation to support fundamental changes in future energy usage for customers, including the integration of distributed energy resources. The AMF program can generate awareness and greater uptake of alternative energy and cost-saving opportunities.
Economic	AMF has the potential to help customers make better-informed energy decisions, promoting reduced energy costs and reduced peak demand. Lowering costs can reduce strain on financially challenged individuals while also provide additional funds for spending in other areas, which could boost economic activity. AMF allows granular electricity and gas consumption data to be available to customers and approved third-party vendors in a timely and efficient manner. Data can provide quicker decision making for both the consumer and third-party vendors. As other grid modernization efforts develop, AMF infrastructure provides data that can support the effort to deploy grid and DER technologies, replacing other potentially capital intensive data collection strategies.
Educational	The AMF program has the potential to raise customer awareness about opportunities to save costs through improved energy efficiency. Data can be used directly—for example, to help customers learn where to adjust their energy usage. Data can also be used indirectly—for example, to gain a broader understanding of how implementing improved energy technologies can save energy and reduce costs. The AMF initiative could be used to develop educational materials on programs that promote increased energy efficiency, grid stability, and resiliency. Metering data can be used to inform utilities and other entities involved in the energy supply chain to make more informed and effective decisions.

Environmental Externalities	Potential to reduce environmental impacts (e.g., greenhouse gas emissions) as a result of energy conservation enabled by advanced metering infrastructure. Potential to increase awareness of environmental issues associated with different energy technology choices. Support state and federal programs aimed at shifting toward greater reliance on clean, renewable technologies and reduced use of older, less efficient energy sources.

8. Conclusion

The advanced meter functionality proposed in this chapter is a foundational element of the Company's effort to meet evolving customer expectations and advance the state's goals set out both in Docket 4600 and more recently, Power Sector Transformation. Not only will this functionality enable more visibility, choice, control, and convenience for customers, but it will continue for allow for safe, reliable, and affordable delivery of energy services. The results of the BCA test show that, based on quantifiable benefits delivered to customers and the grid, a full deployment of AMF can achieve a net positive benefit to cost ratio in both the Rhode Island only deployment scenario and the Rhode Island and Niagara Mohawk joint deployment scenario. Delivering the quantifiable benefits included in the BCA, along with the non-quantifiable societal, economic, educational, and environmental benefits, is critical to the state's transformation effort.

To deploy AMF while managing customer bill impacts, the Company has proposed to implement a new annual PST Plan that will enable a staged approach to project development and approval. Approval of the initial $2 million revenue requirement will enable the company to embark on the next phase of design, including further exploration of partnerships, stakeholder input and a procurement exercise to refine costs. The Company looks forward to working with stakeholders to design and implement an AMF program that advances Rhode Island's goals and delivers meaningful benefits to customers, the grid, and society.

Chapter 9
Performance

Schedule PST -1,

Chapter 9 - Performance

CHAPTER NINE: DRIVING OUTCOMES THAT CUSTOMERS VALUE: THE ROLE FOR PERFORMANCE INCENTIVES IN THIS TRANSFORMATION

1. PERFORMANCE-BASED REGULATION IS ESSENTIAL TO POWER SECTOR TRANSFORMATION

While the fundamental objective of the electric utility to provide safe, reliable, and affordable electricity service has remained relatively constant over the past several decades, new objectives around sustainability, system efficiency, resiliency, grid modernization, distributed energy resource integration, and customer engagement have gained prominence with regulators and customers. And increasingly, these new objectives are transforming expectations for electric distribution utilities. In Rhode Island, these objectives are fundamental to the energy policy goals (discussed in Chapter Two) that have been articulated through Docket 4600 and the Power Sector Transformation Initiative.[1]

Integration of these objectives into the utility business environment requires electric distribution utilities to perform new functions that are materially different from the functions that support their core business, and will require innovation with regard to technology adoption and deployment, business and management practices, and the customer relationship. However, the current regulatory framework creates a disincentive for utilities to take on the risk associated with innovation in support of new goals for the electric system. Although today's regulatory framework supports cost-recovery and earnings on investment deemed prudent by regulators, it is not sufficient to drive innovative utility performance in delivering these new objectives. To best encourage utilities to innovate and to align their financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations, new compensation mechanisms are needed.

A shift toward performance-based regulation is foundational to the power sector transformation envisioned by the state. This chapter proposes first steps in what is likely to be a longer process of evolution that uncovers new opportunities to incent both overall efficiencies and system cost reductions, while also driving exceptional utility performance in areas of importance. By rewarding utilities based on performance, regulation can better mirror the outcomes of competitive markets, where firms earn higher returns if they innovate and provide products and services that create more value for customers.

Through Docket 4600 and Power Sector Transformation the Division, the Company, and numerous stakeholders spoke to the value of incentives in advancing state policy objectives. All

[1] Outside of Rhode Island, similar objectives have provided the foundation for initiatives such as Massachusetts Grid Modernization and New York REV. For example, the four objectives of Massachusetts Grid Modernization are: (1) reducing the effects of outages; (2) optimizing demand, including reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management. See, Order in D.P.U. 12-76-B, June 12, 2014, at 10-13. The NY REV objectives are: (1) customer knowledge and tools that support effective management of their total energy bill; (2) market animation and leverage of ratepayer contributions; (3) system wide efficiency; (4) fuel and resource diversity; (5) system reliability and resiliency; and (6) reduction of carbon emissions. See Case 14-M-010, Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues, at 1-2 (August 22, 2014).

of these parties recognize that new incentives may be necessary to encourage innovation and investments that might not otherwise occur under traditional cost-of-service regulation. In adopting the specific recommendation from Docket 4600 to "Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives," the Rhode Island PUC has recognized their value as well.

The Company firmly believes that carefully designed performance incentives can help advance Rhode Island's energy policy goals and provide broad new benefits to customers. Specifically, the Company believes that incentives are most likely to be appropriate and effective where:

(1) there is a demonstrated market failure or a unique strategic role that can be served by the utility;

(2) there is an opportunity to produce significant benefits to customers and/or promote Rhode Island's energy policy goals; and

(3) the distribution company plays a distinct and clear role in bringing about the desired outcome.

Utility performance incentives are not new to the state of Rhode Island. The PUC has previously approved Company tariffs that allow for the collection of performance incentives associated with the procurement of long-term renewable electricity contracts for retail customers, both from wholesale power providers and, separately, from eligible distributed-generation projects (the latter under the Renewable Energy Growth Program).

With respect to energy efficiency, the PUC has approved shareholder incentives for the Company's energy efficiency programs dating back to 1990.

In addition, under its Service Quality Plan[2], the Company is subject to performance standards in the areas of reliability and customer service with associated metrics, targets, and penalties, with the potential to earn offsets that can be applied against future penalties. These service quality metrics are used to evaluate the Company's performance in meeting its core obligations to customers.

The Company expects that the incentives in this proposal will most closely resemble the existing incentives for energy efficiency, in that they are reward-only and designed to provide increasing rewards with higher levels of performance (with exceptions where incentives relate to milestones). The incentives in the Company's Plan support the delivery of new benefits and savings to customers and in many cases reflect new areas of accountability for the Company that expand beyond its core obligations. In the near term, reward-only incentives are desirable in order to establish performance-based incentives as a beneficial mechanism for both the utility and customers.

[2] The Company's Service Quality Plan is described in Attachment 1 to the Company's Agreement to Modify Performance Benchmarks (Agreement) filed with the Rhode Island Public Utilities Commission (PUC) on March 14, 2007, and approved by the PUC in Docket 3628.

The Company is proposing two types of new performance incentives. The first type includes new incentives related to capital efficiency for electric distribution investments, including (1) an incentive for capital savings on complex capital projects included in the Company's Infrastructure, Safety, and Reliability (ISR) Plan; and (2) an incentive for improvements in the efficient delivery of overhead distribution line projects. The Company also discusses its plans to propose similar incentives for it gas distribution business.

The second type of incentive the Company is proposing is a portfolio of performance incentive mechanisms that reward performance in delivering key programs and objectives aligned with state policy goals. The Company views the performance incentive mechanisms included in this proposal as a first step in a broader evolution of the regulatory framework that will unfold as the power sector transforms, bringing new opportunities to customers. Successful implementation of these incentives is likely to foster further innovation in the Rhode Island power sector, by providing both the Company and regulators with the confidence to identify and propose new areas for incentives that might drive further efficiencies or customer benefits. The Company recognizes that it may make sense over time to modify this portfolio of performance incentive mechanisms through additions of new incentives or through other modifications as the Company develops experience in measuring and delivering these objectives, deploys new technologies, and as state regulatory and policy priorities evolve.

Combined, these proposed incentives work to advance the three goals for a new regulatory framework articulated in the PST Phase One Report:

- Control the long-term costs of the electric system;
- Give customers more energy choices and information; and
- Build a flexible grid to integrate more clean energy generation.

2. PROPOSED CAPITAL EFFICIENCY INCENTIVES

The Company's ability to identify efficiencies in the delivery of capital investments has the potential to generate meaningful savings for customers over time. However, the current regulatory framework does not reward the utility for identifying and delivering such efficiencies. An important element of performance-based regulation is the movement toward a regulatory framework that provides a more equal incentive for the delivery of operating and capital cost savings. To that end, the Company is proposing two new incentives related to the efficient delivery of capital. The first proposal targets complex capital projects and provides incentives for the Company to find ways to deliver agreed-upon outputs at a lower-than-forecast cost. The second proposal is designed to encourage increased productivity in the delivery of overhead distribution-line projects, providing incentives for the Company to innovate to more efficiently deliver roughly $45m 'routine' capex per year. In addition to the two proposed incentives, the Company describes its intent to develop and propose incentives for capital cost efficiencies for its gas business. While this falls outside of the scope of the Power Sector Transformation Initiative, it is included in this chapter to reflect the Company's ambition to incorporate performance incentives across both its electric and gas businesses.

2.1. Complex Capital Projects Capital Cost Incentive

This incentive would reward the company for delivering a portfolio of complex capital projects that close in a given fiscal year at a cost below an accepted baseline capital cost estimate.

Summary of incentive structure and scope

Under this proposal, the award for a given year will be calculated based on a comparison of the actual capital costs at closure over the lifetime of the set of projects closing in a given fiscal year, to a baseline estimate of cost – based on final sanction costs – for the same set of projects. The comparison of actual to baseline capital costs will be done on a portfolio basis, rather than project by project, such that any capital spend in excess of sanctioned amounts for a given closed project will count against savings for the full portfolio of projects closed in that fiscal year.

The Company proposes that when a portfolio of projects is delivered for a capital cost that is less than the baseline cost, the Company retains 50% of the savings. The Company proposes to cap the value of savings that might be retained by the Company in a given year at $2.5 million.

The Company proposes that this new incentive mechanism would start in FY 2020, and would apply to all complex capital projects closing in FY 2020 and beyond. Based on the size of projects that closed in FYs 2015, 2016, and 2017, this incentive is expected to apply to portfolios reflecting approximately $5 million to $15 million in capital expenditures annually, though this range may change over time.

Determining project eligibility and baseline capital costs

For projects that have already been included in a previous ISR and are scheduled to close during FY 2020, or FY 2021, the Company proposes a rolling process to have the Commission review and confirm those projects as eligible for the incentive, and to formally note their final sanction capital costs as the baseline. Looking ahead, for new complex projects added to the ISR, the Company proposes to indicate eligible projects and propose final sanction capital costs as the baseline for evaluating performance within its ISR Plan.

Reporting and incentive payment

For each portfolio of closed projects, the Company will report to the PUC, as part of its annual PST Reconciliation Filing, as well as its ISR Reconciliation Filing, its actual capital expenditures relative to the total capital cost estimate, with a calculation of the value of the incentive payment the Company has earned. The Company proposes that any positive incentives earned in a given fiscal year would be collected through the PST Provision in the following fiscal year.

2.2. Construction Costs per Mile Productivity Incentive

The Company is also proposing an incentive for productivity improvements in the delivery of overhead distribution line projects. The metric underlying this incentive would be a composite per-mile construction costs metric that the Company is currently working to develop and benchmark. The projects that would be captured by this metric represent the overhead distribution line budget of the Company's approved spend under the ISR.

Under this incentive, the Company would be rewarded with a positive revenue adjustment for achieving target reductions in construction costs per mile as defined by the metric. The awarded incentive would increase in proportion to performance, and would be capped with a maximum annual value. Any positive incentives earned in a given fiscal year would be collected through the PST Provision in the following fiscal year.

The Company proposes to develop a baseline and targets for this metric for consideration in the Electric ISR filing to take effect in FY 2020.

2.3. Intent to Propose Gas Capital Efficiency Incentives:

The Company is considering proposing incentives for its gas distribution business. The Company expects to propose specific metrics and targets for such an incentive for consideration as part of its FY 2020 ISR filing.

3. NATIONAL GRID'S PERFORMANCE INCENTIVE MECHANISMS PROPOSAL

The Company has developed its performance incentive mechanisms proposal to support the policy priorities identified by stakeholders through Docket 4600 and emphasized during the Power Sector Transformation Initiative. The Company proposes to develop performance incentive mechanisms in the following three categories: (1) System Efficiency, (2) Distributed Energy Resources, and (3) Network Support Services. These three categories align with the recommended categories for performance incentive mechanisms in the PST Phase One Report. The report describes each category as follows: (1) System Efficiency incentives are intended "to achieve savings for ratepayers from the utility controlling long-term utility costs"[3]; (2) Distributed Energy Resources "includes targeted incentives for a range of distributed energy resources that require utility action to implement"[4]; and (3) Network Support Services "includes actions that the utility will need to accomplish to demonstrate capabilities essential for the future utility."[5] The Company believes that incentives in these three categories, described in more detail below, will advance the objectives identified in both the Power Sector Transformation Initiative and Docket 4600, and provide new benefits and opportunities to customers.

(1) System Efficiency – Incentives around system efficiency are intended to drive the Company to deliver both near and long-term savings to customers by encouraging more efficient use of the system. Reductions in system coincident peak demand, for example, can reduce forward capacity market costs to customers below what they otherwise might have been, and can also reduce transmission expenses. Further, integration of new load in a manner that does not increase peak demand can avoid or minimize the infrastructure investments needed to support this additional load, and create downward pressure on rates by spreading the fixed costs of the system over more load.

[3] PST Phase One Report, page 24.
[4] *Ibid*.
[5] *Ibid.*

(2) Distributed Energy Resources—Incentives to encourage the Company's active efforts to integrate distributed energy resources support the state's goals of encouraging customer engagement and investment, promoting emissions reductions, and supporting economic development within the state. The new performance incentive mechanisms in this category were developed to be complementary to existing incentives for distributed energy resources, such as energy efficiency and distributed generation contracts.
(3) Network Support Services – Incentives in this category reward the Company for actions that support the development of a more digitized and decentralized system. These activities lay the groundwork for the longer term transformation of the power sector.

Within each of these three categories, the Company is proposing a set of performance incentive mechanisms intended to encourage successful delivery of new programs and broader Company activities aligned with Rhode Island state goals.

Each performance incentive is composed of (1) a metric to capture Company results in the specific area of interest; (2) targets that indicate performance goals or milestones for each metric; and (3) a financial incentive associated with the achievement of each target. Where a range of targets is included, the Company proposes to earn incremental rewards along the line between targets and earnings levels. The individual metrics and the Company's approach to setting targets are described in more detail below; specific targets and proposed earnings levels are summarized in Table 9-1, which provides a high-level overview of the performance incentive mechanisms in each category and the proposed maximum earnings opportunities for each. The maximum earnings level is denominated in basis points;[6] however, the Company proposes that the incentives not be implemented as an adjustment to ROE, but rather as a payment calculated based on equivalent basis point value determined by the size of the rate base in the given year. The Company has followed the following principles in development of this proposal.

- Establish incentives that reward the Company for successful delivery of activities, programs, investments, and outcomes that are foundational to power sector transformation. In some cases, these incentives are designed to reward the Company for successful delivery of innovative new programs and investments as proposed, in recognition that these activities fall outside of its traditional core obligations and provide new opportunities for customers and benefits to the system. Targets and milestones have been set to reflect this objective. Incentives are justified in these cases to drive outstanding Company performance in these new areas, and to ensure that – given their relevance to state policy goals and importance to laying a successful foundation for power sector transformation – they remain priorities for Company leadership. In other cases, the incentives are designed to reward the Company for achieving particular performance outcomes that provide benefits or savings to customers. In these cases, the minimum target required for earning an incentive represents a clear step beyond what the Company currently achieves.
- Align, to the extent possible, with the proposed performance incentive mechanisms in the PST Phase One Report. In following this principle, the Company has developed performance incentive mechanisms that are directly in support of the Rhode Island state

[6] Specifically, a basis point refers to 1 basis point of electric distribution common equity grossed up for taxes. For the rate year ending August, 2019, the Company has estimated the value of a basis point to be $59,493.

energy goals articulated in Docket 4600 as well as the goals articulated in the Power Sector Transformation Initiative. Where the Company has omitted metrics included for performance incentives that were included in the PST Phase One Report, a rationale for this omission is provided.

- Assign values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due the activity encouraged by the incentive. The Company has supported the proposed values for individual incentives using analyses of benefits and costs where possible. Where quantification is not possible, the Company has provided a qualitative description of the most significant benefits and costs.

Table 9-1: Overview of Proposed Performance Incentive Mechanisms and Maximum Earnings Opportunity in Basis Points

Category and Supporting Metrics	2019	2020	2021
System Efficiency	**23.5**	**23.5**	**23.5**
Monthly Transmission Peak Demand Reduction	3	3	3
Forward Capacity Market Peak Demand Reduction	18	18	18
EV Off-Peak Charging Rebate Participation	2.5	2.5	2.5
Distributed Energy Resources	**29.5**	**29.5**	**29.5**
DG-Friendly Substation Transformers	10	10	10
DR -- Connected Solutions Participation	5	5	5
DR -- C&I Participation	5	5	5
Electric Heat Initiative	2	2	2
Electric Vehicles	3.5	3.5	3.5
Behind-the-Meter Storage	2	2	2
Utility-Owned Storage	2	2	2
Network Support Services	**22**	**22**	**22**
VVO Pilot Impacts	2	2	2
AMF Customer Engagement and Deployment	2	2	2
Interconnection -- Time to ISA	6	6	6
Interconnection -- Avg days to system modification	6	6	6
Interconnection -- Estimated vs actual costs	6	6	6
Total	**75**	**75**	**75**

3.1. System Efficiency Performance Incentive Mechanisms

The Company proposes three System Efficiency metrics: Monthly Transmission Peak Demand Reduction, Forward Capacity Market Peak Demand Reduction, and EV Off-Peak Rebate Participation. The Company expects that there will be value in additional System Efficiency performance incentive mechanisms in the near to medium term, particularly upon deployment of AMF. For example, the Company believes that time-varying rate participation, which was included as a performance incentive mechanism in the PST Phase One Report, will be a valuable metric when such rates are more broadly enabled by AMF.

Monthly Transmission Peak Demand Reduction and Forward Capacity Market Peak Demand Reduction: The Company's peak demand reduction metrics are intended to provide savings to customers in two ways: reductions in monthly transmission billings from New England Power to Nantucket Electric and through reductions in forward capacity market costs. The Monthly Transmission Peak Demand Reduction metric will measure the annual sum of reductions in the monthly peaks on a year-over-year basis, based on the overall Company loads used in calculating monthly ISO-NE Regional Network Service (RNS) billings (loads will be weather-normalized for the purposes of applying this metric).[7] The Forward Capacity Market Peak Demand Reduction metric will measure reductions in the weather-normalized annual peak load on a year-over-year basis, using the same data. To control for weather variations, the Company proposes to normalize the peak for the average weather for the past 10 annual peak days.

The Company also proposes that the weather-normalized load reported for both metrics be adjusted, as warranted, to account for the addition of any large new electric loads on the system in a given year. These adjustments would be based on actual new peak demands seen at the new large load sites that are coincident with monthly or annual peak load.

The Company expects a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts such as the deployment of volt-var optimization (VVO), and demand response to contribute to meeting these peak demand reduction targets.

To establish the annual peak target, the Company used its internal peak forecast, including forecast peak impacts from energy efficiency,[8] solar PV, and VVO, as well as the programs proposed in this Plan. With this information, the Company developed minimum, mid- point, and maximum targets. All three target points were set to represent incremental effort beyond what is expected under the Company's energy efficiency program plans. For the annual peak targets, the Company expects that payment of the incentive would require demonstration of savings beyond what is achieved through energy efficiency programs. Monthly transmission peak targets were set to encompass and expand upon the annual peak savings, with the size of the expansion increasing from year to year. The Company set initial targets for the sum of monthly peak reductions in recognition that it will have to develop an appropriate program to manage monthly peak loads to directly provide customer savings reductions in billed transmission costs relative to what would occur absent the program. Workpaper 9.1 – Peak Demand Reduction Targets includes supporting material for the development of these targets.

[7] See the Company's February 16, 2017 Electric Retail Rate Filing, specifically the discussion presented in Tiffany Forsyth's testimony and Schedule TMF-2, page 1 of 2. Available at: http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate(2-16-17).pdf
[8] Energy efficiency targets incorporated in the forecast include targets for combined heat and power.

Table 9-2: Monthly Transmission Peak Demand Reduction Targets and Basis Points

Annual sum of monthly peak MW reductions				
	2019	2020	2021	Basis Points
Minimum	28	23	26	1
Target	36	34	36	1.75
Maximum	47	44	46	2.5

Table 9-3: Forward Capacity Market Peak Demand Reduction Targets and Basis Points

Annual peak demand reduction (MW)				
	2019	2020	2021	Basis Points
Minimum	22	18	19	6
Target	29	26	26	12
Maximum	38	31	31	18

EV Off-Peak Charging Rebate Participation: The EV Residential Off-Peak Charging Rebate participation metric will measure the number of customers participating in the Company's proposed rebate program for off-peak EV charging relative to the Company's target and budgeted participation levels. This program supports the state's system efficiency goals by encouraging current and future EV drivers to shift EV charging loads to off-peak hours. The program will also offer an important opportunity to demonstrate Rhode Island customers' response to, and potential savings from, time-variant price signals. Customers will benefit from increased familiarity with such price signals in advance of broader deployment of time-varying rates.

The Company set its participation target for the off-peak charging rebate program to reflect the target participation levels that support the Company's proposed program budget. Thus, the incentive will reward the Company for timely and successful marketing and delivery of this new customer offering. The minimum target allows the Company to start to earn an incentive when it approaches 80% of the target participation level for the year; the maximum allows earnings to increase for participation up to 120% of the participation target should the Company find implementation efficiencies that enable enrollment beyond funded target levels.

Table 9-4: EV Off-Peak Rebate Participation Targets and Basis Points

Number of participants				
	2019	2020	2021	Basis Points
Minimum	80	188	400	2
Target	100	250	500	2.5
Maximum	120	300	600	3

3.2. Distributed Energy Resources Performance Incentive Mechanisms

The Company's seven proposed Distributed Energy Resources metrics are intended to directly support the achievement of multiple Rhode Island regulatory goals articulated in the Docket 4600 stakeholder report and adopted by the PUC, particularly:

- 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).
- Address the challenge of climate change and other forms of pollution.
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits.
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.

The Company has proposed specific performance incentive mechanisms intended to complement the existing incentives the Company has in place in support of energy efficiency, the Renewable Energy Growth Program, and renewable energy contracts. Metrics for these new performance incentive mechanisms include: (1) DG-Friendly Substations; (2) Demand Response- Connected Solutions Participation; (3) Demand Response- C&I Participation; (4) Electric Heat Initiative; (5) Electric Vehicles; (6) Behind-the-Meter Storage; and (7) Company-Owned Storage. The demand response participation metrics will reward the Company for successfully increasing demand response program participation, which will support system-coincident peak reductions that can provide generation and transmission capacity savings, while also promoting customer engagement. The DG-friendly substation transformers metric, as well as the EV, heat, and storage metrics will advance the State's goal of promoting clean, distributed energy resources and increasing customer engagement and investment.

DG-Friendly Substation Transformer: this metric will indicate the number of substation transformers that have ground fault detection (3V0) installed and are capable of readily accommodating distributed generation, thereby allowing for the installation of distributed generation capacity up to the thermal rating of a particular substation transformer. The targets for this incentive reflect ambitious goals for the 3V0 program the Company included in its recent ISR filing. These targets will enhance the system's ability to accommodate higher penetration levels of distributed generation and accelerate the interconnection of distributed resources that might otherwise be delayed under a less proactive approach to these upgrades.

Table 9-5: DG-Friendly Substation Transformers Targets and Basis Points

Cumulative 3V0 installations over 2019-2021				
	2019	**2020**	**2021**	**Basis Points**
Minimum	1	2	3	1
Target	3	6	12	6
Maximum	5	10	15	10

Demand Response- Connected Solutions Participation: This metric for this incentive will be number of residential customers participating in the Company's Connected Solutions program. The Company will develop targets for this metric under the Company's Energy Efficiency 1-Year Plan for 2019. This metric is intended to reward the Company for effective and efficient customer engagement, and is not intended to be duplicative of existing incentives. Basis points are intended to be illustrative of the potential size of the incentive.

Table 9-6: Connected Solutions Customer Participation Targets and Basis Points

Number of Particpants				
	2019	**2020**	**2021**	**Basis Points**
Minimum	Targets to be developed in 1-Year EE Plan			1
Target				3
Maximum				5

Demand Response- C&I Participation: The metric for this incentive will be number of contracted MWs in the Company's C&I demand response programs. Similar to the Company's proposed Connected Solutions participation metric, the development of targets for this metric will be developed as part of the Energy Efficiency 1-Year Plan for 2019. This metric is intended to reward the Company for effective and efficient customer engagement, and is not intended to be duplicative of existing incentives. Basis points are intended to be illustrative of the potential size of the incentive.

Table 9-7: C&I Customer Participation Targets and Basis Points

Enrolled MW				
	2019	2020	2021	Basis Points
Minimum	Targets to be developed in 1-Year EE Plan			1
Target				3
Maximum				5

Electric Heat Initiative: This metric for this incentive is the annual CO_2 reductions attributable to the ground source heat pump and equipment incentives being offered under the Electric Heat Initiative. Targets for these metrics were developed to represent the Company's effective delivery of program objectives, in particular, achieving effective targeting of highly-emitting customers, maximizing participation on a fixed incentive budget, and encouraging proper system design and utilization. Workpaper 9.2 – Electric Heat Initiative Targets includes supporting material for the development of this target.

Table 9-8: Electric Heat Initiative Targets and Basis Points

Metric tons CO2 avoided per year				
	2019	2020	2021	Basis Points
Minimum	119	178	156	0.67
Target	149	223	195	0.83
Maximum	179	268	234	2

Electric Vehicles:

This metric is intended to capture the impact of the Company's EV program on EV adoption in the Rhode Island relative to predicted market trends. The metric will measure incremental increase – above predicted levels – of personal EVs in the state on an annual basis. The targets were set to represent an improvement in Rhode Island upon the forecast trend for EV sales in New England as projected by the Energy Information Administration's Annual Energy Outlook 2017. Proposed targets and basis points are summarized in the table below and reflect a 20%, 40%, and 80% improvement over the EIA's projected EV sales growth for New England (corresponding to the minimum, target, and maximum levels, respectively). Workpaper 9.3 – Electric Vehicles Targets includes supporting material for the development of this target.

Table 9-9: Electric Vehicles Targets and Basis Points

Annual incremental registered EVs (above forecast)				
	2019	2020	2021	Basis Points
Minimum	130	176	239	1
Target	259	352	477	2
Maximum	519	703	954	3.5

Behind-the-Meter Storage: The Company is proposing to include an incentive for behind-the-meter storage in response to the recommendations PST Phase One Report. Although the Company does not have a program in place to encourage behind-the-meter storage, the Company is committed to working with interested customers to evaluate opportunities for storage. The proposed metric for these efforts is the incremental MW of installed behind-the-meter storage each year.

Table 9-10: Behind-the-meter Storage Targets and Basis Points

Incremental installed MW				
	2019	2020	2021	Basis Points
Minimum	1	1	1	0.33
Target	3	3	3	1
Maximum	6	6	6	2

Company-Owned Storage: The proposed metric for this incentive is will the number of MW of Company-owned storage used to support peak reduction or provide other system benefits. This metric would include the Company's storage proposal described in Chapter Seven. In addition, the Company expects to continually evaluate the business case for storage, and has set targets and associated basis points to encourage this ongoing evaluation.

Table 9-11: Company-Owned Storage Targets and Basis Points

Incremental installed MW				
	2019	2020	2021	Basis Points
Minimum	1	1	1	0.33
Target	3	3	3	1
Maximum	6	6	6	2

3.3. Network Support Services Performance Incentive Mechanisms

The Company's proposed Network Support Services performance incentive mechanisms are composed of the following five metrics: (1) AMF Customer Engagement; (2) VVO Pilot Delivery; (3) Interconnection Support- Time to ISA; (4) Interconnection Support- Average days to System Modification; (5) Interconnection Support- Estimate versus Actual Costs. At this time, the Company is not including proposed performance incentive mechanisms for access to customer information, and income eligible customers, both of which were included in the PST Phase One Report recommendations. The Company believes that there is value in an incentive related to access to customer information, but that it would be best developed as AMF deployment advances. Similarly, with respect to income eligible customers, the Company suggests that development of a performance incentive should follow implementation of the Company's proposals affecting income eligible customers. Finally, while the Company has not proposed a broad customer engagement performance incentive mechanism as described in the PST Phase One Report, it has developed performance incentive mechanisms to support customer engagement in specific contexts, such as the EV off-peak charging rebate, demand response programs, and, as discussed in this section, AMF deployment.

AMF Customer Engagement and Deployment: This metric focuses on the Company's progress and success in conducting customer outreach and education in support of AMF deployment, as well as the Company's success in achieving early deployment targets. Successfully educating customers about the benefits that AMF will be critical to achieving their engagement and, ultimately, to encouraging participation in programs that will enable the achievement of benefits from AMF. Achieving early deployment targets is critical to enabling the rapid delivery of customer and system benefits from AMF. These incentives would reward the Company for successfully driving internal resources to achieve an ambitious delivery timeline. Proposed milestones and basis points are summarized in the table below, followed by additional explanation of the customer engagement milestones.

Table 9-12: AMF Customer Engagement and Deployment Milestones and Basis Points

Year	Milestones	Basis Points
2019	Deliver customer engagement plan	2
2020	Conduct and report on customer awareness survey	1
2020	Commence mass scale meter deployment	1
2021	Achieve 30% deployment and customer portal access	2

A short explanation of the customer engagement milestones follows:

- Deliver customer engagement plan. The Company would submit a plan that reflects customer insights from internal customer research, knowledge gained from Company experience with pilot projects, and industry best practices. The Company expects that specific requirements for earning an incentive for this milestone will be further developed through this proceeding.
- Conduct and report on customer awareness survey. The Company intends to conduct both pre- and post-deployment surveys to establish a baseline of customer awareness and to inform outreach efforts, and to measure the impact of customer engagement programs.

VVO Pilot Delivery: This metric will reward the Company for successful delivery of the VVO Pilot proposed through the ISR. Under this pilot, the Company will evaluate AMF's contribution to power sector transformation objectives, and has proposed an initial small-scale deployment of 16,000 meters. The immediate focus of this project is the integration of interval voltage data from AMF meters into the optimization algorithms of the volt-var optimization/conservation voltage reduction (VVO/CVR) to improve system efficiency. The VVO Pilot Delivery metric will measure 1) the timely delivery of the project; and 2) delivery of the expected system impacts of the project, specifically, a minimum additional 1% reduction in energy consumption and peak demand on top of what is expected from primary VVO/CVR optimization. This performance incentive mechanism will reward the Company for a successful project that lends itself to an improved understanding of the system optimization benefits from AMF, and help lay the foundation for broader successful deployment of AMF.

Table 9-13: VVO Pilot Delivery Milestones and Basis Points

Year	Milestones	Basis Points
2019	Project in service	2
2020	Achievement of enhanced VVO/CVR impacts	2
2021	Achievement of enhanced VVO/CVR impacts	2

Interconnection Support – Time to ISA: This metric will capture the Company's average performance over all processes against the required timeframes specified in the Interconnection Tariff for submitting an executable Interconnection Service Agreement (ISA). The Company would receive a performance incentive based on the degree to which it outperforms the requirements in the Interconnection Tariff. Specifically, the metric will be calculated as the percent difference between:

(1) the aggregate number of business days allowed by the Interconnection Tariff to provide an executable ISA over all processes; and

(2) the average time measured in business days necessary for the Company to provide a customer with an executable ISA, commencing from the date a completed application is received, over all processes.

Table 9-14: Time to ISA Targets and Basis Points

Percent below required timeframe				
	2019	2020	2021	Basis Points
Minimum	5%	5%	5%	2
Target	10%	10%	10%	4
Maximum	15%	15%	15%	6

The Interconnection Support – Average Days to System Modification: This metric will capture the Company's average performance over all processes against the required timeframes in the Interconnection Tariff for completion of system modifications identified by the Company in the ISA. The Company would receive a performance incentive based on the degree to which it outperforms requirements in either the Interconnection Tariff or an average of actual days versus expected in all executed ISA. Specifically, the metric will be calculated as the percent difference between:

(1) the total aggregate number of business days allowed by the Interconnection Tariff to complete system modifications, over all processes; and

(2) the average time measured in business days necessary for the Company to complete system modifications, commencing from the date of execution of the ISA, over all processes.

Table 9-15: Average Days to System Modification Targets and Basis Points

Percent below required timeframe				
	2019	2020	2021	Basis Points
Minimum	5%	5%	5%	2
Target	10%	10%	10%	4
Maximum	15%	15%	15%	6

Interconnection Support – Estimate versus Actual Cost: This metric will focus on the accuracy of the cost estimates provided to interconnecting customers. Specifically, the metric would be calculated as the overall percent difference between the sum of costs estimated by the Company for interconnection and the sum of the actual costs paid by interconnecting customers.

Table 9-16: Estimate versus Actual Cost Targets and Basis Points

+/-% difference				
	2019	2020	2021	Basis Points
Minimum	10%	10%	10%	0
Target	6%	6%	6%	4
Maximum	4%	4%	4%	6

4. Impact on Policy Goals and Benefits to Customers

In light of the recent the PUC's Docket 4600 Guidance, the Company has reviewed its performance-based regulation proposal in terms of its impacts on each of the goals identified in the Docket 4600 Stakeholder Report and adopted by the PUC.

Table 9-17: Overview of Proposal Impacts on State Energy Policy Goals

GOALS FOR "NEW" ELECTRIC SYSTEM	Advances?/Detracts From/Is Neutral Toward?
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 – Supports utility delivery of capital cost, and capacity and transmission cost savings.\
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – Supports utility delivery of capacity and transmission cost savings; encourages distributed energy resource development; promotes customer engagement and supports timely AMF deployment.
Address the challenge of climate change and other forms of pollution	Advances – Reductions in energy use during peak periods will reduce carbon emissions; increasing and expediting distributed energy resource integration will deliver larger and earlier CO_2 reductions.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances – Enables efficient interconnection of distributed energy resources, encourages electrification of vehicles and heat; rewards company investment in and support of energy storage.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral – Does not address compensation of distributed energy resources.
Appropriately charge customers for the cost they impose on the grid	Advances – Rewards the Company for achieving participation targets in EV off-peak rebate; rewards timely deployment of AMF, which will support development of rates that are more aligned with cost-causation.
Appropriately compensate the distribution utility for the services it provides	Advances – Rewards timely deployment of AMF, which will support development of rates more aligned with cost-causation and support appropriate utility compensation.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design,	Advances – Proposed incentives reward the Company for activities that are geared toward meeting state policy goals and that generate

cost recovery, and incentive	opportunities and savings for customers.

While the Company has not conducted a quantitative benefit-cost analysis (BCA) of the full performance incentive mechanism portfolio, it has quantified benefits and costs where possible and provided a qualitative explanation of key benefits in cases where quantification is not possible. A summary of the relevant analysis for each performance incentive mechanism category follows. Supporting analysis is included in Workpaper 9.4 – Incentives Benefits.

4.1. System Efficiency

The system efficiency metrics provide two major benefits to customers. Annual peak reductions will – after three years – contribute to avoided generation capacity costs by reducing the amount of capacity that must be secured through the ISO-NE Forward Capacity Auction (FCA). Reductions in monthly peaks reduce the transmission costs billed to the Company relative to what they otherwise would have been. These benefits are discussed in more detail below.

The Company has not quantified the costs of achieving the proposed peak demand reduction targets. Peak demand reductions will be supported by the Company's energy efficiency programs, though, as noted above, earning an incentive will require additional incremental annual peak demand reductions. Peak demand reductions will also be supported by growth in distributed generation, and at a smaller scale, by projects such as VVO/CVR (include in the FY 2019 ISR) and other projects described in this document – all of which are intended to serve multiple objectives. In addition, achievement of peak demand reduction targets will likely require new Company efforts to foster renewable energy integration, storage, and demand response. Not all of these programs have been defined by the Company at this point.

While the Company has set annual Forward Capacity Market Peak Demand Reduction targets for the years 2019-2021, it is important to note that these reductions will not result in material capacity costs savings in the FCA until 2022. In the years 2020 and 2021, customers could expect to benefit from some savings through a reduced capacity share. The Company expects that MW reductions made in support of the 2019-2021 targets will be maintained for the duration of project lives.[9] To illustrate the magnitude of potential annual savings, the Company estimated the net present value (NPV) of the annual value, in the year 2022, of the benefits from avoided capacity needs due to the achievement of the 2019-2021 targets. Comparing this value against the NPV of the annual value of the incentive in 2021, and against the NPV of the incentive over the period 2019-2021, demonstrates that the incentive represents a small fraction of the overall benefits being created, particularly given that these benefits will carry well beyond 2022.

[9] An exception to this might be called demand response events, however, the Company expects to be able to grow demand response enrolled and participating capacity as programs ramp up, such that it can be expected that the same reductions are achieved (and expanded) from year to year.

Table 9-18: Comparison of Benefits and Incentive Value for Forward Capacity Market Peak Demand Reduction

	NPV of Benefit in 2022 Due to 2019-2021 Targets	NPV of 2021 Value of Incentive	NPV of Value of Incentive (2019-2021)
Minimum	$ 2,594,124	$ 285,752	$ 886,970
Target	$ 4,816,010	$ 571,505	$ 1,773,940
Maximum	$ 6,901,576	$ 857,257	$ 2,660,910

For the Monthly Transmission Peak Demand Reduction metric, an estimate of potential customer savings can be developed using current transmission rates. The Company has estimated customer savings from the targets using the current RNS rate of $110.35 kW-yr.[10] Table 9-19 displays the present value of estimated customer savings over 2019-2021 based on current rates. Under the Company's proposed incentive, customers would retain approximately two-thirds to three quarters of the savings in this example. Note that the savings estimates in this example are likely to be conservative, as they ignore the cumulative effect of year over year savings.

Table 9-19: Potential Savings and Company Earnings from Monthly Transmission Peak Reductions

	NPV of Customer Savings (2019-2021)	NPV of Incentive (2019-2021)	Share of Savings to Customer
Minimum	$575,166	$ 147,828	0.74
Target	$779,652	$ 258,700	0.67
Maximum	$1,016,979	$ 369,571	0.64

With respect to the EV off-peak charging rebate, the limited size of the proposed program prevents it from demonstrating positive quantified net benefits as a stand-alone program in the Company's BCA. However, the Company believes that the proposed size of the incentive is justified due the value placed on the transition to time-varying rates in Docket 4600, and the value that this program will provide in understanding customer response to time-differentiated price signals. The program is also important to the state's goals for beneficial electrification as it will both improve the economics of EV ownership and help ensure that additions of new load from participating EV owners are concentrated during off-peak hours.

[10] See the Company's February 16, 2017 Electric Retail Rate Filing, specifically the discussion presented in Tiffany Forsyth's testimony and Schedule TMF-2, page 1 of 2. Available at: http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate(2-16-17).pdf

4.2. Distributed Energy Resources

As discussed earlier in this chapter, the Distributed Energy Resources performance incentive mechanisms are intended accelerate system improvements that support greater deployment of distributed generation resources, increased penetration of distributed energy resources, and customer investment in their energy infrastructure. The activities underlying these performance incentive mechanisms will lead to quantifiable benefits based on a number of outcomes, including:

- Reductions in CO_2 and criteria pollutant emissions;
- Avoided energy and capacity costs;
- Avoided renewable energy credit (REC) costs; and
- In the case of EVs and heat electrification, avoided costs of non-electric fuels.

Further, the activities supported by these incentives directly support of a number of Docket 4600 and Power Sector Transformation Initiative objectives. They will drive increasing customer investment in their facilities, where that investment provides recognizable net benefits. These activities will also promote economic development and help to strengthen the Rhode Island economy, and directly support the state's CO_2 emissions reduction goals.

The Company has proposed the largest incentive around the DG-Friendly Substation metric. The Company's proactive installation of 3V0 has the potential to expedite interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits described above. However, the Company has not quantified the net benefits to customers from these efforts, due to the assumptions that would have to be made about the timing of distributed generation installations absent these investments, the number and size of installations accelerated, and the specific technology being installed.

The potential earnings under the Electric Vehicles and Electric Heat Initiative performance incentive mechanisms in comparison with the net benefits from these initiatives are presented in Table 9-20. The maximum earnings opportunity for the Electric Vehicles performance incentive mechanisms has been set based on the NPV of the quantified net benefits associated with the portion of the program geared toward customer vehicle conversion, such that over 60% of net benefits remain with customers. While the quantified net benefits of the Electric Heat Initiative suggest that customers would retain only about 25% of the net benefits, the Company believes that the proposed maximum incentive equal to two basis points annually is warranted given that the Electric Heat Initiative provides important economic development benefits that have not been quantified in the BCA. In particular, the program will support the growth in the state of a labor-intensive sector with a direct positive impact on the building trades.

Table 9-20: Comparison of Potential Incentive Value and Quantified Net Benefits for the Electric Transportation Initiative and Electric Heat Initiative

	Program Net Benefits (NPV)	Incentive Value 2019-2021 (NPV)	Share of Quantified Net Benefits to Customer
Electric Vehicles	$1,414,836	$517,399	0.63
Electric Heat Initiative	$396,389	$295,657	0.25

4.3. Network Support Services

The activities supported by the Company's proposed Network Support Services performance incentive mechanisms are, as discussed above, foundational to broader power sector transformation. While it is difficult to quantify the benefits of the metrics in this category, these incentives will serve to support the Company's timely delivery of operational and customer benefits from AMF while also rewarding enhanced interconnection practices that provide cost savings to developers and accelerate the achievement of CO_2 emissions reductions, peak demand reductions, energy savings, local economic development, and other benefits associated with distributed energy resources.

The VVO Pilot Delivery metric will deliver additional energy and peak demand reductions due to further optimization of VVO/CVR. In doing so, it will demonstrate the potential system efficiencies that can be obtained through the combination of AMF and VVO/CVR.

While it is difficult to quantify the benefits of the AMF Customer Engagement and Deployment metrics, these incentives are provided in recognition of the foundational role that AMF will play in the transformation of the power sector. These incentives will encourage the Company to achieve the benefits of AMF, discussed in great detail in Chapter 4, as expeditiously as possible through effective customer engagement and ambitious deployment schedules.

Similarly, the benefits from achieving the interconnection targets are difficult to quantify, but timely and efficient interconnection of distributed generation is foundational to providing the benefits from distributed generation, including:

- Reductions in CO_2 and criteria pollutant emissions;
- Avoided energy and capacity costs; and
- Avoided REC costs.

The value that the Company has assigned to the interconnection metrics reflects the Company's view of the importance of efficient interconnection processes, both because of their broader implications for Rhode Island's distribution system, and their foundational role in achieving the state's energy and economic development goals.

5. Evaluation and Reporting

As part of its annual PST Reconciliation Filing (discussed in Chapter Ten), the Company will report on prior calendar year performance relative to each target and the calculations for the incentives earned. Incentives will be recovered on a per-kWh basis from all customers through the PST Provision.

The Company notes that many of the proposed performance incentive mechanisms and associated targets are directly related to products and services proposed in this Plan. To the extent the Commission does not approve or otherwise curtails those initiatives, the portfolio of performance incentives mechanisms may require modification in order to serve as a meaningful and appropriate set of incentives for the Company. In the future, the Company may wish to propose modifications to performance incentive mechanisms as new information emerges that might impact the appropriateness of metrics or targets in place.

Chapter 10
Revenue Requirement

Schedule PST - 1

Chapter 10 – Funding the Transformation

CHAPTER 10: FUNDING THE TRANSFORMATION

1. INTRODUCTION

The success of the Plan will be dependent upon sufficient revenue to recover the Company's incremental costs to construct, own, operate, and maintain its proposed PST investments. Success will also depend upon the Company's ability to fund the management, marketing, and evaluation of its PST Initiatives, as well as system enhancements needed to implement the initiatives. To that end, in Appendices 10.10 and 10.11 (for electric and gas respectively), the Company is submitting a PST Provision that provides for the recovery of forecasted and actual PST-related incremental capital and operation and maintenance ("O&M") costs, subject to full reconciliation, for PST Initiatives approved by the PUC, pursuant to an annual pre-approved budget. In addition, the PST Provision also provides the Company an opportunity to earn performance incentives associated with the PST Initiatives and to recover earned performance incentives through the PST Reconciliation Factors.

As described in more detail herein, the Company will submit by January 1 each year its annual PST Plan and PST Factors for its upcoming PST Plan Year, which coincides with the beginning of Company's fiscal year on April 1, based on the Company's forecasted costs for such initiatives. The Company will seek approval of both its annual PST Plan and PST Factors by April 1, to allow the Company to implement its annual PST Plan coincident with the beginning of its fiscal year.

In addition, by August 1 of each year, the Company proposes to file an annual report with the PUC and Division on the progress of its PST Initiatives, including information on the prior fiscal year's activities. The Company is cognizant that, in implementing its PST Plan in any fiscal year, the circumstances encountered during the year may require reasonable deviations from the original PST Plan. In such cases, the Company would explain in its annual report any significant deviations the Company implemented during the prior PST Plan Year from the annual PST Plan approved by the PUC.

Also by August 1, the Company will submit a PST Reconciliation Filing in which it will reconcile the prior PST Plan Year's revenue requirement based on actual investment and O&M expenses and the revenue billed from the PST Factors in effect during the same PST Year. The Company will seek approval of its PST Reconciliation Factors annually in this filing, to take effect the following October 1.

The FY 2019 level of incremental O&M expense contained in the Company's proposed Plan is $3.593 million. The Company is not seeking funding for any PST related capital investment in FY19. Each of these categories of spending is addressed below. In addition, a description of the Company's proposed revenue requirements and associated illustrative calculations are outlined herein. Finally, the Company is providing a PST Provision for review and approval.

2. DESCRIPTION OF KEY COMPONENTS OF THE PST PROVISION

The PST Provision provides for the recovery of incremental costs associated with the Company's PST Plan approved by the PUC. To be eligible for recovery, PST Plan costs must: (1) be pre-authorized by the PUC; (2) include only costs of investing in PST Initiatives; (3) be incremental to those costs that the Company currently recovers through any other rate, charge, or factor; and (4) be prudently incurred. The Company's rates for Retail Delivery Service are subject to adjustment to reflect the operation of the PST Provision.

For all PST Initiatives except the expansion of Grid Modernization activities, including AMF, the Company's PST-related costs are proposed to be recovered through two cost recovery factors:

(1) PST Factors, designed to recover the Company's cumulative actual PST capital investment for years prior a given PST Plan Year, and forecasted PST capital investment for the PST Plan Year, plus forecasted O&M Expense for the PST Plan Year; and

(2) PST Reconciliation Factors, designed to recover or credit any over or under recovery of the Annual Revenue Requirement on cumulative actual PST capital investment through the end of the prior PST Plan Year plus actual O&M expense for the prior PST Plan Year.

The Company is proposing the PST Factors and PST Reconciliation Factors for Grid Modernization Expansion, including AMF, be based upon the categorization of the nature of the spending in this initiative to better define how the benefits will accrue to customers. The Company is proposing to categorize capital and O&M expense as those that are customer-related (i.e., driven by the number of customers the Company serves) and those that are distribution-related or shared between customer-related and distribution-related (i.e., driven by the overall benefit to the Company's distribution system and the service it provides and common costs such as program and project management). By categorizing the costs of Grid Modernization Expansion, including AMF, in this way, the Company is able to allocate the revenue requirement and O&M expenses to its customer rate classes in a manner consistent with how the same costs are allocated to the rate classes as part of a general rate case as reflected in a cost of service study and, ultimately, and allocated cost of service study. By taking this approach of categorizing the costs in this way to allow for this type of allocation, when these investments and O&M expenses eventually become a part of a distribution cost of service study, the allocation of the overall revenue requirement will be aligned with how these costs were allocated to and recovered from customers through the PST Factors.

The PST Factors are proposed to be applied to all retail delivery service bills. The PST Factors will be adjusted annually, subject to the PUC's review and approval. The operation of these factors is described in more detail below.

2.1 PST Factors

The PST Factors will recover both capital investment and O&M expense and will be effective during the PST Plan Year, coincident with the PST Plan upon which they are calculated. Each PST Initiative will have its own factor based on forecasted capital investment and O&M expense. For capital cost recovery, the factor for each PST Initiative shall recover the Annual Revenue Requirement on Cumulative Capital Expenditures, including Forecasted Capital Expenditures as approved by the PUC in the Company's annual PST Plan Filings. The factor for each PST Initiative will also recover the Forecasted O&M Expense as approved by the PUC in the Company's annual PST Plan Filings. The Company shall calculate separate revenue requirements and add to it the PST Initiative's forecasted O&M expense, resulting in a factor for each PST Initiative. The Company will aggregate all factors for all PST Initiatives into the PST Factors for billing purposes.

PST capital investment and O&M expense recovery shall include an annual reconciliation of the Annual Revenue Requirement on the sum of Actual Capital Expenditures for all PST Plan Years plus Actual O&M Expense to actual billed revenue generated from the PST Factors for the applicable PST Plan Year. The balance from the reconciliation shall accrue interest monthly at the same rate as that paid on customer deposits. The recovery or crediting of the reconciliation balance, including interest, shall be reflected in PST Reconciliation Factors. The Company shall submit a filing by August 1 of each year (Reconciliation Filing) in which the Company shall propose the PST Reconciliation Factors to become effective for the 12 months beginning October 1. The amounts approved for recovery or crediting through the PST Reconciliation Factors shall be subject to reconciliation with amounts billed through the PST Reconciliation Factors, and shall accrue interest monthly at the same rate as that paid on customer deposits, and any difference, including interest, reflected in future PST Reconciliation Factors. The Company shall prepare separate reconciliations for each PST Initiative based upon the calculation of separate revenue requirements plus O&M expense and actual billed revenue specific to each PST Initiative factor, shall calculate reconciliation factors for each PST Initiative, and aggregate all reconciliation factors for all PST Initiatives into the PST Reconciliation Factor for billing purposes.

2.2 PERFORMANCE INCENTIVES

The PST Provision also includes a Performance Incentive Factor which is designed to recover performance incentives earned by the Company as a result of the Company achieving specific performance metrics pertaining to the efficient delivery of the Company's capital program (Capital Efficiency) and the achievement of objectives in the system efficiency, distributed energy resources, and network support services. Except otherwise noted in Appendix A of the PST Provision, the Company shall measure actual performance against the performance metrics identified during the calendar years shown in the appendix.

3. DESCRIPTION OF ILLUSTRATIVE REVENUE REQUIREMENT CALCULATION

Based upon the estimated amounts for the PST Plan, the Company has calculated the revenue requirement resulting from the projected incremental PST capital and O&M expenditures. Please refer to Appendix 10.1. This section contains a description of the revenue requirement models and illustrative revenue requirement calculations. These calculations would form the basis for the PST Factors, described above. The revenue requirement calculations assume costs during FY 2019 for a transitional six month period, effective October 1, 2018, that would be eligible for recovery and included in the first annual Reconciliation Filing which will propose PST Reconciliation Factors to become effective October 1, 2019, and then annual recovery for future fiscal years, effective April 1, 2019. The pre-tax rate of return on rate base would be that rate of return approved by the PUC in the Company's present general rate case and, going forward, it would change as the PUC may approve changes to the rate of return in future proceedings. Any change in the rate of return would be applicable on a prospective basis effective on the date on which the change is effective.

Appendix 10.1, Pages 1 and 2, provides a summary of the total revenue requirement on all PST initiatives, including recovery of PST O&M expense, for the six months ending March 31, 2019 and further provides an illustrative revenue requirement for the fiscal years (FY) ending March 31, 2020, March 31, 2021, and March 31, 2022. Page 1 presents the summary of revenue requirements including the costs of deploying AMF and Modern Grid programs on a Rhode Island only basis, with the total revenue requirement amount shown on Line 11 and the total revenue requirements for the Company's electric and gas divisions shown on Lines 7 and 10, respectively (noting that for FY20, FY21 and FY22 the revenue requirements are illustrative). Page 2 presents the same summary revenue requirement view including the cost of deploying AMF and Modern Grid programs in Rhode Island if one of the Company's affiliates in Massachusetts or New York deploys these programs at the same time. The subsequent pages present the individual revenue requirement calculations supporting each of five PST initiatives, as follows:

Illustrative Revenue Requirements	**Appendix Reference**
Summary of Revenue Requirements	Appendix 10.1
Grid Mod – Rhode Island only deployment	Appendix 10.2
Grid Mod – multi jurisdiction deployment	Appendix 10.3
AMF – Rhode Island only deployment	Appendix 10.4
AMI – multi jurisdiction deployment	Appendix 10.5
Electric Transportation	Appendix 10.6
Electric Heat	Appendix 10.7
Storage	Appendix 10.8
Solar	Appendix 10.9

For the six months ending March 31, 2019, the Company is proposing to recover O&M expense only. The initial six months of costs are based on the work that can be achieved in that initial period, specific to the context of each individual program. In most instances, the initial costs are 'start up' costs for the program (including next level program design and early implementation activities), ahead of PST capital investments and ongoing implementation costs to follow in FY 2020 and beyond. The revenue requirement calculations included in the above noted appendices present the initial six months of costs described above, and for illustrative purposes, a full 12 months of recovery related to PST capital investments and O&M expense, for each FY beginning with the FY ending March 31, 2020. The proposed PST capital investment and O&M expenses for each PST initiative follow the cost information as outlined in the program BCAs and as provided in Appendix 2.1 and Appendix 4.1. The revenue requirement calculations all follow the same general methodology described below.

In general, the total revenue requirement for each PST program consists of (1) O&M expenses associated with each program, and (2) a capital component consisting of the a return of and on any incremental PST investment where applicable. For those PST programs involving a level of capital investment, the capital component of the revenue requirement consists of: (1) a return on the average rate base derived from incremental PST capital investments, including taxes, (2) book depreciation expense incurred on incremental PST capital investments, and (3) incremental property tax expense projected to be assessed on the incremental PST investment.

Each PST revenue requirement (actual for FY19 and illustrative thereafter) begins with a summary revenue requirement page, which details the O&M components of the revenue requirement separately from the PST capital investment components of the revenue requirement (if applicable), as well as the delineation of O&M and capital components between the Company's electric and gas divisions where the PST investments benefit the customers of both businesses. The summary page is followed by the revenue requirement calculation(s) on the various capital investments of that PST program.

Each capital revenue requirement begins with the determination of depreciable net plant in service that will be included in the rate base for that PST program. Because depreciation expense is affected by plant retirements, any projected plant retirements driven by PST investment have been deducted from plant additions in determining the depreciable plant upon which book depreciation expense is calculated. Retirements, however, do not affect rate base as both "plant in service" and "depreciation reserve" are reduced by the installed value of the plant being retired and therefore have no impact on net plant. Cost of removal if applicable affects rate base but not depreciation expense. Consequently, the cumulative cost of removal is combined with cumulative depreciable capital investment to derive the cumulative net plant, included in PST rate base, upon which the annual PST revenue requirement is calculated.

Book depreciation expense is computed using the applicable depreciation rate, based on the PST investments' assigned plant unit code(s), and as approved in the Company's most recent distribution base rate case. In the year of investment, the calculation of book depreciation assumes a half-year convention. In the following years, current year book depreciation is added to the prior years' book depreciation to arrive at cumulative book depreciation, which is included in the calculation of year-end rate base as a deduction, which is described below.

Year-end rate base includes the cumulative net plant described above adjusted for accumulated depreciation and accumulated deferred tax reserves. The deferred tax amount arising from the PST capital investment equals the difference between book depreciation and tax depreciation on those PST capital investments, times the effective federal tax rate. Each illustrative revenue requirement calculation is accompanied by a calculation of tax depreciation which outlines the tax assumptions used to arrive at total projected annual tax depreciation expense. Generally, the tax depreciation calculation assumes that some portion of PST capital investment will be eligible for immediate federal tax deductions on the Company's corresponding FY federal income tax returns. These accelerated tax deductions may include but are not limited to: bonus depreciation, which is currently set to expire on December 31, 2019 and capital repairs deductions. These accelerated tax deductions have the effect of increasing accumulated deferred taxes, therefore lowering the amount of rate base upon which the revenue requirement is calculated and ultimately lowering the amount that customers will pay under the proposed PST mechanism. Any remaining portion of PST capital investment which does not qualify for accelerated tax depreciation treatment would be depreciated over an estimated tax life, which is determined under the guidance of the Company's tax department and the classification of plant investments on the Company's books (i.e. plant unit code). Total accelerated tax deductions plus cost of removal and any loss on partial retirements recorded for tax purposes comprises total annual tax depreciation carried forward to the revenue requirement calculation. The current year's tax depreciation is then accumulated with prior years' tax depreciation amounts to arrive at the cumulative tax depreciation amount. Cumulative tax depreciation is compared to cumulative book depreciation to determine the cumulative book/tax timer, to which the effective federal tax rate is applied to calculate the accumulated deferred tax reserve.

The deferred tax calculations included in the illustrative revenue requirements include offsets for tax net operating losses (NOL) and tax proration adjustments. NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future. If any portion of the Company's NOL is determined to be driven by PST investment, the Company will offset the accumulated deferred income tax liability by that portion of the NOL. Conversely, if the Company is able to utilize any portion of its NOL attributable to PST investment in future years, the Company will increase accumulated deferred income taxes in the fiscal year that NOL is utilized. The deferred tax proration adjustment fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). When a regulatory filing is based on a future period, tax normalization rules stipulate that deferred taxes must be prorated to reflect the period of time that the cumulative deferred income tax reserves are in rate base. As the proposed PST mechanism is based on a future period using forecasted PST capital investments, the proration adjustment has been included here as an offset to the deferred tax reserve. Therefore, total net deferred tax reserve includes the summation of the deferred tax reserve net of NOL and proration adjustments.

The year-end PST rate base is comprised of the net PST capital investment less accumulated depreciation and the net deferred income tax reserve. The revenue requirement is calculated on an average rate base. In the year of investment, the calculation of average rate base uses a half-year convention (end of year rate base divided by 2). In the following years, the calculation of average rate base is derived by taking the beginning and year-end rate base divided by 2.

Average rate base is then multiplied by the pre-tax rate of return approved in the Company's most recent rate case. For illustrative purposes, the PST revenue requirements provided in the appendix to Chapter 10 utilize the Company's proposed rate of return in Docket 4770. That rate of return is used to compute the amount of return and taxes included in the PST capital component of revenue requirement. To this, depreciation expense and property tax expense are added to arrive at the total annual capital component of the PST revenue requirement.

Appendix 2.1

Appendix 2.1,

Program BCA

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Reference Document

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The joint NG-KPMG approach to developing BCAs involved iterating on both quantitative & qualitative benefits

Gather data & key inputs

Review models from other jurisdictions to identify value drivers

- Evaluate relevance to Rhode Island-specific rate case
- Identify and acquire outstanding data

Build initial BCA models

Leverage previous models, RI 4600, and the AESC to develop a RI-specific framework

- Work with project teams to ensure that data is not missing, all benefits are captured, and costs are represented
- Build consistency across models while still allowing for some flexibility where appropriate to project structure

Review with Teams

Review with project teams & get feedback

- Stress test & QA/QC models
- Challenge key assumptions and provide alternative values

Optimize programs

Assist teams with program optimization based on initial BCA results

- Find areas of hidden value
- Reevaluate project configurations and implications (as necessary)
- Include other ratios to provide additional context and points of comparison

Develop Qualitative Analysis

Identify & articulate qualitative benefits

- Discuss how projects align with policy, social and/or economic goals of Rhode Island
- Evaluate benefits that fall outside of the AESC framework, but are still relevant to the state

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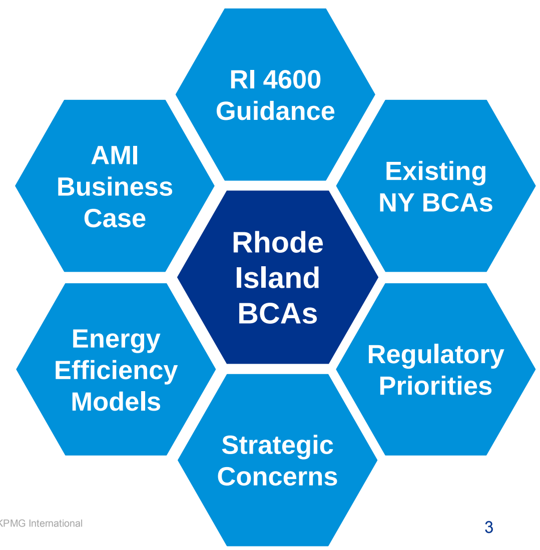
More tactically, this resulted in the RI BCAs taking into account a broad set of considerations during development

Design Principles

Consistency
- Where possible, a single method for the same assumption
- Common naming conventions, design and style
- Increased stakeholder agreement on the above

Transparency
- Simple to understand assumptions & calculations
- Adequate documentation and commentary on work

Flexibility
- Design that allows for quick updates of variables with global or local impacts (as appropriate)
- Ability to combine and/or disaggregate future business cases with minimal effort



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Benefits were "translated" to Rhode Island accounting for other jurisdictions, precedent and regulatory direction

Benefits & Costs Mapping		Test Applicability			Projects / Elements			
NY Benefit/Cost Category	RI Benefit/Cost Category	SCT	UCT	RIM	Electric Transportation	Electric Heat	Company-Owned Solar	Company-Owned Storage
Avoided Generation Capacity Costs ("AGCC")	Forward Commitment: Capacity Value	✓	✓	✓				
Avoided LBMP	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	✓	✓	✓				
	REC (Renewable Energy Credit Cost) Cost/Value	✓	✓	✓				
Avoided Transmission Capacity Infrastructur	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Transmission Losses	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Ancillary Services	Forward Commitment: Ancillary Services Value			✓	N/A	N/A	N/A	
Wholesale Market Price Impacts	Energy Demand Reduction Induced Price Effect (DRIPE) + Capacity Demand Reduction Induced Price Effect (DRIPE)		✓	✓				
Avoided Distribution Capacity Infrastructure	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided O&M	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Distribution Losses	Distribution Delivery Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Net Avoided Restoration Costs	Distribution System and Customer Reliability/Resilience Impacts	✓	✓	✓	N/A	N/A	N/A	N/A
Net Avoided Outage Costs	Distribution System and Customer Reliability/Resilience Impacts	✓			N/A	N/A	N/A	N/A
Net Avoided CO2	GHG (Greenhouse Gas) Externality Costs	✓						
Net Avoided SO2 and NOx	Criteria Air Pollutant and Other Environmental Externality Costs	✓					N/A	N/A
Net Non-Energy Benefits	Non-Electric Avoided Fuel Cost	✓					N/A	N/A
Program Administration Costs	Utility/Third Party Developer Renewable Energy, Efficiency, or DER Costs	✓	✓	✓				
Added Ancillary Service Costs	Utility/Third Party Developer Renewable Energy, Efficiency, or		✓	✓	N/A	N/A	N/A	N/A
Incremental T&D and DSP Costs	Electric transmission infrastructure costs for Site Specific	✓	✓	✓	N/A	N/A	N/A	N/A
Participant DER Cost	Utility/Third Party Developer Renewable Energy, Efficiency, or	✓						
Lost Utility Revenue (Cost shift from non-participants to	Program Participant/Prosumer Benefits/Costs		✓	✓				
Net Non-Energy Costs	Non-Energy Costs/Benefits: Economic Development	✓			Not applied	Not applied	Not applied	Not applied

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The BCAs are collected in a single, consistent tool

Contents

Section	Worksheet	Description
1	Cover	
2	Key Terms	This page provides descriptions of acronyms used across the models
3	Contents	The contents page provides descriptions of and links to the sheets in this model
4	RI BCA Summary	BCA summary and comprehenesive benefits and costs by investment category
5	Electric Vehicles (EV) - BCA	Electric Vehicles BCA Model
5.1	EV - BCA Summary	EV BCA ratios and comprehensive benefits and costs
5.2	EV - Inputs	EV control panel, inputs, and sub-models
5.3	EV - Benefits	Detailed build-up of EV benefits
5.4	EV - Costs	Detailed build-up of EV costs
6	Electric Heat (EH) - BCA	Electric Heat BCA Model
6.1	EH - BCA Summary	EH BCA ratios, comprehensive benefits and costs, and sensitivity analyses
6.2	EH - Inputs	EH control panel, inputs, and sub-models
6.3	EH - Benefits	Detailed build-up of EH benefits
6.4	EH - Costs	Detailed build-up of EH costs
7	Solar (SOL) - BCA	Solar BCA Model
7.1	SOL - BCA Summary	SOL BCA ratios and comprehensive benefits and costs
7.2	SOL - Inputs	SOL control panel, inputs, and sub-models
7.3	SOL - Load & Energy Costs	SOL annual system load and corresponding hourly avoided energy costs
7.4	SOL - Benefits	Detailed build-up of SOL benefits
7.5	SOL - Costs	Detailed build-up of SOL costs
8	Energy Storage (ES) - BCA	Energy Storage BCA Model
8.1	ES - BCA Summary	ES BCA ratios and comprehensive benefits and costs
8.2	ES - Inputs	ES control panel, inputs, and sub-models
8.3	ES - Benefits	Detailed build-up of ES benefits
8.4	ES - Costs	Detailed build-up of ES costs
9	Inputs - General	

- Sections 1-3 represent a general introduction to the model, defining key terms and acronyms as well as providing links to worksheets
- The Table of Contents breaks down the organization of the model and links you to the various worksheets
- Each model includes project specific summary, inputs, benefits and costs tabs

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The tool clearly summarizes outcomes while giving project leads the ability to easily drill down into details

The RI BCA Summary tab includes a SCT and RIM score for each investment category

RI National Grid BCA Summary

BCA Summary by Investment Category

Investment Categor	SCT	RIM
Electric Vehicles	1.02	0.13
Electric Heat	1.12	2.42
Solar	0.84	0.62
Energy Storage	0.45	0.49

Electric Heat: Comprehensive Benefits & Costs

	Applicable Cost Test			Electric Heat - BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	277,788
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided (	$	(1,121,845)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
		x	x	Wholesale Market Price Impacts	$	(5,073)
	x			Greenhouse Gas (GHG) Externality Costs	$	527,088
	x			Criteria Air Pollutant and Other Environmental Costs	$	222
	x			Non-Electric Avoided Fuel Cost	$	4,162,394
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	3,552,155
					$	**7,292,803**
Costs	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER C	$	1,073,830
	x			Program Participant / Prosumer Benefits / Costs	$	2,275,503
					$	**3,349,332**

- The RI BCA Summary tab also includes a more comprehensive benefits and costs table
- This includes all the modeled benefits and costs for the SCT and RIM (and UCT for reference)
- It also indicates which benefits/costs apply to each type of recognized test

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Specific investments also have complete breakdowns

EH - BCA Summary

Societal Cost Test
RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	0	$	-
	Greenhouse Gas (GHG) Externality Costs	$	527,088
	Criteria Air Pollutant and Other Environmental Costs	$	222
	Non-Electric Avoided Fuel Cost	$	4,162,394
	Economic Development	$	-
	0	$	-
		$	**3,745,721**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or	$	1,073,830
	Program Participant / Prosumer Benefits / Costs	$	2,275,503
		$	**3,349,332**

BCA Ratio 1.12

RIM Cost Test
RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	Wholesale Market Price Impacts	$	(5,073)
	0	$	-
	0	$	-
	0	$	-
	0	$	-
	Change in Utility Revenue	$	3,552,155
		$	**2,603,098**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or DER	$	1,073,830
	0	$	-
		$	**1,073,830**

BCA Ratio 2.42

Comprehensive Benefits & Costs

	Applicable Cost Test			Electric Heat - BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	277,788
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
		x	x	Wholesale Market Price Impacts	$	(5,073)
	x			Greenhouse Gas (GHG) Externality Costs	$	527,088
	x			Criteria Air Pollutant and Other Environmental Costs	$	222
	x			Non-Electric Avoided Fuel Cost	$	4,162,394
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	3,552,155
					$	**7,292,803**
Cost	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER	$	1,073,830
	x			Program Participant / Prosumer Benefits / Costs	$	2,275,503
					$	**3,349,332**

There is also a list of the comprehensive benefits & costs included in each project's summary tab

Each investment project has its own individual summary which includes the individual benefits & costs segments for the respective cost tests

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Inputs are similarly separated into global and project-specific categories to minimize potential errors

General Assumptions

Assumption	Value	Unit	Source
Line Losses	8.0%	%	AESC 2015, p. 286, ISO Distribution Losses.
Wholesale Risk Premium (WRP)	9.0%	%	AESC 2015, Appendix B
Distribution Losses	8.0%	%	AESC 2015, Appendix B
Real Discount Rate	1.4%	%	AESC 2015, Appendix B
Percent of Capacity Bid into FCM (%Bid)	75.0%	%	AESC 2015, Appendix B
After-tax WACC	7.5%	%	See email from Josh Nowak
Inflation Rate	2.0%	%	

To minimize repetition, a general inputs tab is included which contains all global assumptions used across the model

Unit Conversions

Assumption	Value	Unit	Source
Pounds to Tons conversion	0.0005	#	Standard value
kg to pounds conversion	2.2046		
kWh to MWh conversion	1000		

Some examples of globally-defined variables are AESC pricing, emissions assumptions, unit conversions, time assumptions, residential heat pricing, etc.

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Economic development benefits all share a common method and application across BCAs as well

Review of Economic Development Method

- Valued the increased GDP in Rhode Island attributable to each of the program investments
- Used the REMI input-output analysis model to measure the increased economic activity created by the program
  - Developed a GDP number resulting from increased incomes and spending
  - Further categorized benefit types for additional analysis (direct vs. indirect vs. induced)
- For a number of reasons it was elected that these not be included directly in evaluation of the BCA results:
  - For many of the proposed initiatives, there are still some outstanding parameters (specific procurement plans, siting characteristics, etc.) that would lower the precision of any economic development measures evaluated
  - GDP output are large relative to the size of the programs under consideration, creating a "masking" effect that makes it more difficult to properly evaluate the investments on their own merits

Methodology Breakdown

1 Program investment → **2** Jobs supported → **3** New income created → **4** GDP increased

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Transportation

Reference Document

November 2017

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Project Overview – Transportation

Project Description

- National Grid will invest in the construction of 362 Charging Ports throughout the state of Rhode Island from 2018 to 2020
- Charging stations will be built for use by general consumers as well as fleet and transit vehicles
- National Grid will also build 12 dedicated charging points and adopt 12 heavy duty vehicles into the fleet over 3 years
- The incremental cost of these vehicles will be amortized over the course of their 10-year life
- National Grid will also begin a 3 year pilot program offering a rebate to customers who participate in their Off-peak charging pilot program to drive interest and collect additional data for use in refining future offerings

Modeling Overview

- For every charging port built, a given rate of EV adoption results from the mere presence of these charging stations
- In addition, Rhode Island and National data is used to estimate the number of miles these vehicles would travel and efficiency levels
- Using these key inputs, estimations are made on total internal combustion engine vehicle miles displaced, total energy capacity increase, and total energy usage increase
- These numbers are then used to tabulate the total costs and benefits

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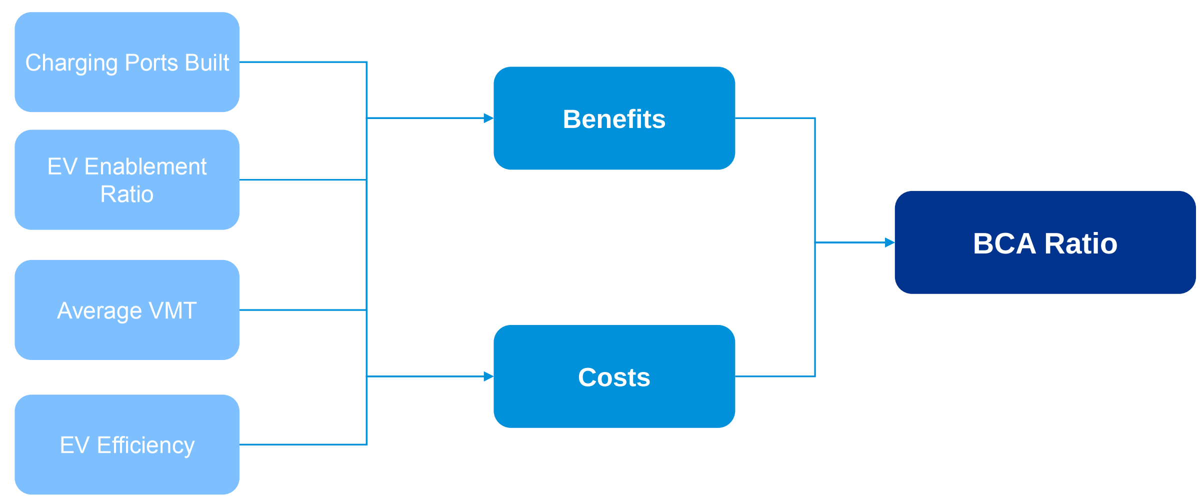
Model Overview

Transportation Model Schematic



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Key Inputs Table

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Key Inputs	Definition	Model Usage	Source(s)
Charging Ports Built	• Total number of Consumer as well as Fleet & Transit charging ports built (374)	*Used together to approximate the total number of electric vehicles adopted by the program*	• Transportation Initiative - Draft Testimony (Karsten Barde) • CALSTART • Auto Alliance • Alternative Fuels Data Center
EV Enablement Ratios	• Approximation of the number of electric vehicles adopted to the construction of each port • There are different ratios depending on the type of vehicle		
Average VMT	• Average number of miles traveled annually per vehicle • Differs depending on vehicle type	*Used with total vehicles enabled to project the total electricity usage increase and avoided fuel cost attributable to the program*	• RITA • RI DOT • Transportation Initiative - Draft Testimony (Karsten Barde)
Vehicle Efficiency	• For EV's: Average number of miles traveled per kWh of electricity • For internal combustion engine (ICE) vehicles: Average number of miles traveled per gallon of fuel		
BEV	• Battery Electric Vehicle – Make up about 30% of the consumer EV market • Cover 95% of miles on battery power	*Use these specifications to help determine total electricity usage from charging* *These values are also used in fuel displacement cost*	• NY Model Assumptions • Transportation Initiative - Draft Testimony (Karsten Barde)
PHEV	• Plug in Hybrid Electric Vehicle – Make up about 70% of the consumer EV market • Cover 85% of miles on battery power		
BEB	• Battery Electric Bus – Assumed to be 100% of the heavy duty vehicles adopted • Cover 95% of miles on battery power		
HD Fleet PHEV	• Heavy Duty Plug in Hybrid Electric Vehicle – 12 vehicles to be adopted by National Grid • Cover 50% of miles on battery power		

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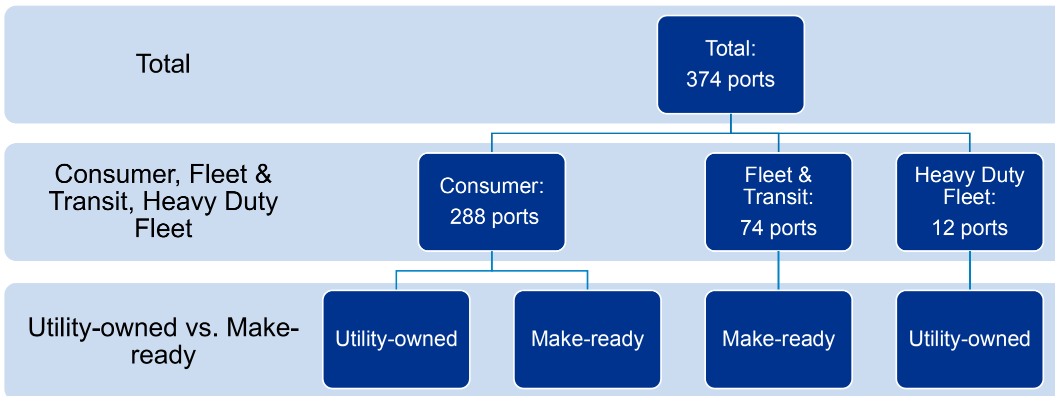
Key Input #1 – Charging Ports Built



- ❑ National Grid will be administrating the construction of 374 total charging ports
- ❑ Of those, 288 ports will be consumer facing and 78 ports will be for fleet and transit vehicles
- ❑ On the consumer side, ~50% will be utility-owned and operated

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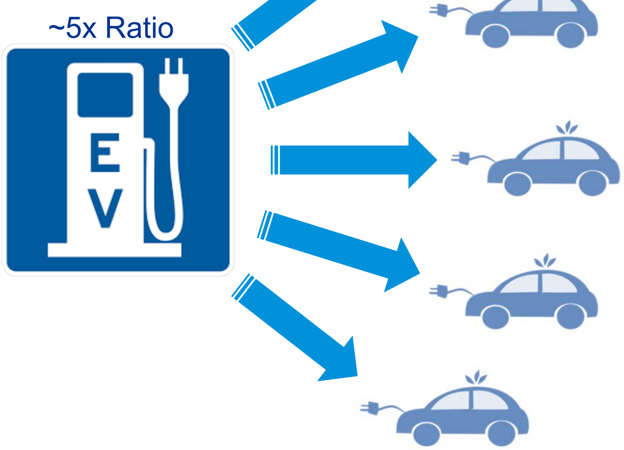
Key Input #2 – EV Enablement Ratios



- Projected # of electric vehicles that will be adopted due to the construction of each port
- Calculated by benchmarking the average # of vehicles per port in other states
- This assumption is still significantly lower than the current national average
- Ratio assumptions
  - Consumer: 5.25 vehicles/port
  - Light Duty Fleet: 2 vehicles/port
  - Ridesharing: 5.25 vehicles/port
  - Heavy Duty Buses: 4 buses/port
  - Heavy Duty Fleet Vehicles: 1 truck/port

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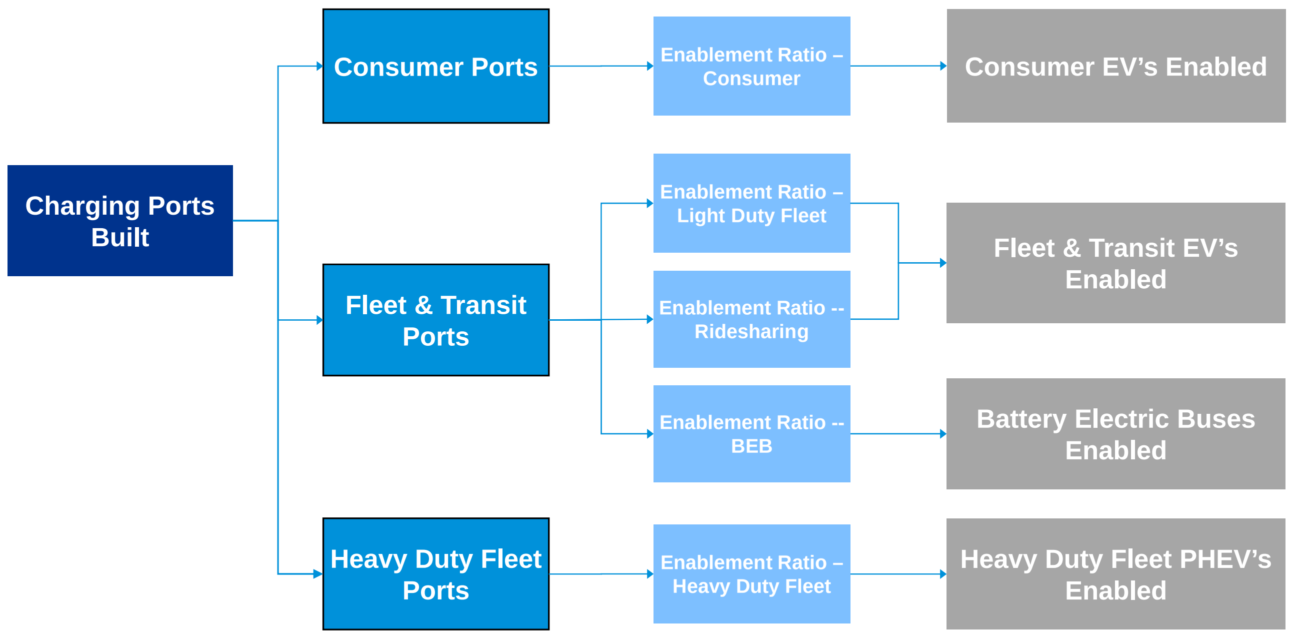
Electric Vehicles Enabled



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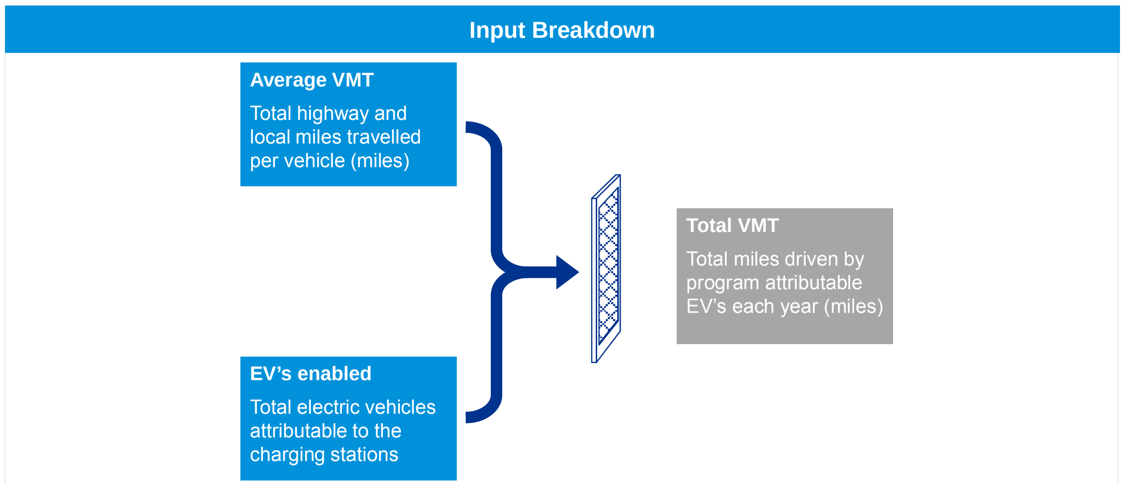
Key Input #3 – Average VMT



- ❑ Average annual miles driven per vehicle in Rhode Island
- ❑ Calculated by leveraging highway and local driving data
- ❑ Average VMT differs depending on vehicle function (i.e. consumer vs. ridesharing)

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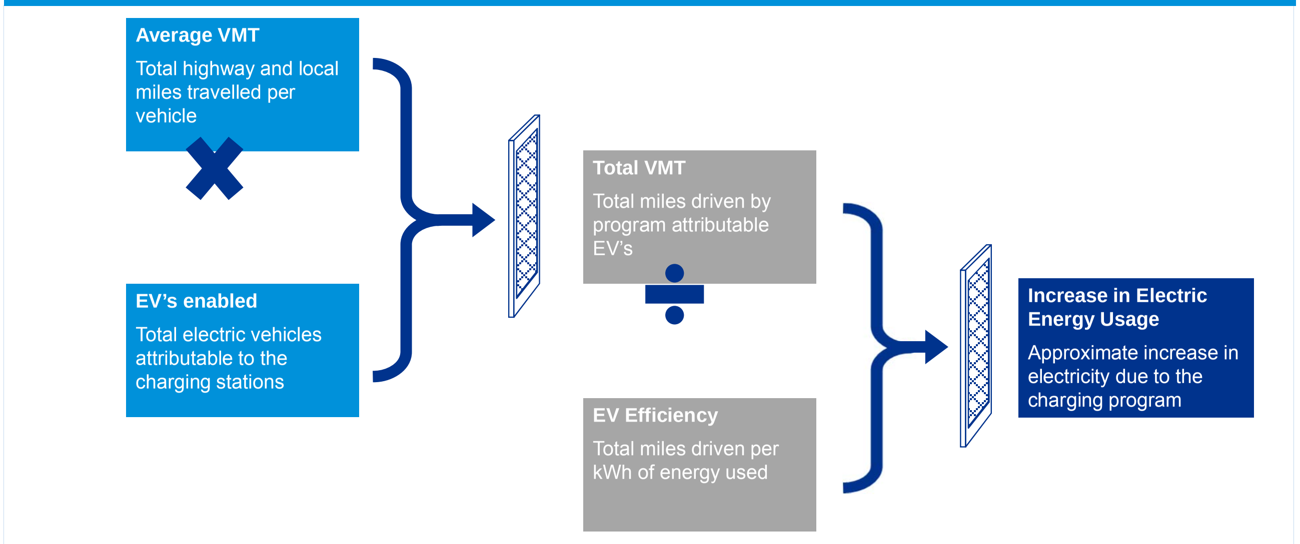
Key Input #4 – EV Efficiency

Input Breakdown



Dividing Total VMT by average Electric Vehicle Efficiency yields an estimate of the total increase in electric energy usage

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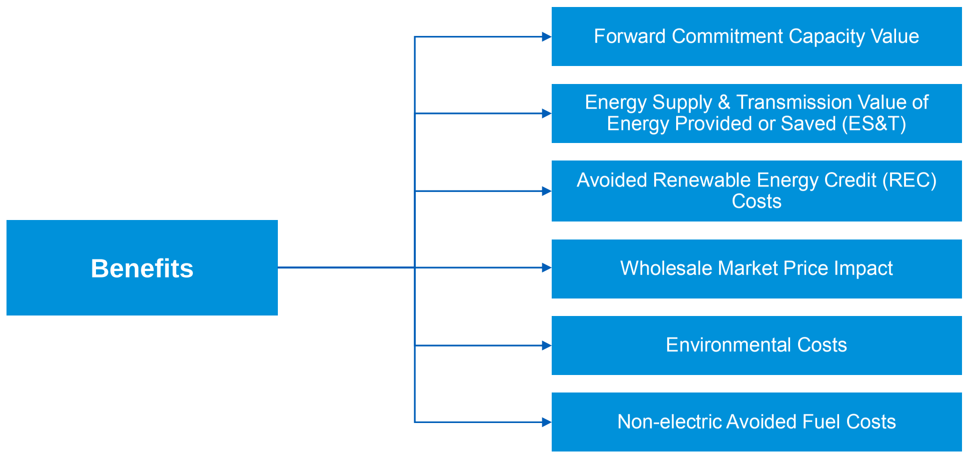
Benefits – Overview

Benefits Components



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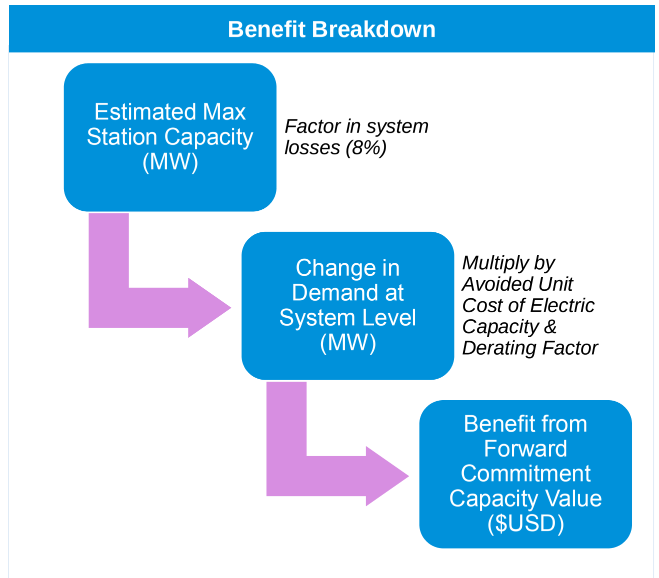
Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because bidding into the forward capacity market takes place 4 years in advance in Rhode Island
- In the case of EV charging stations, the program will lead to an increase in the load demands of the system
- This value is negative, but is accounted for in benefits to maintain consistency across BCAs
- Off-peak rebate cannot participate in the Forward Capacity Market due to its 3-year term; there is a capacity benefit from this program, but not one that can be captured within the AESC framework



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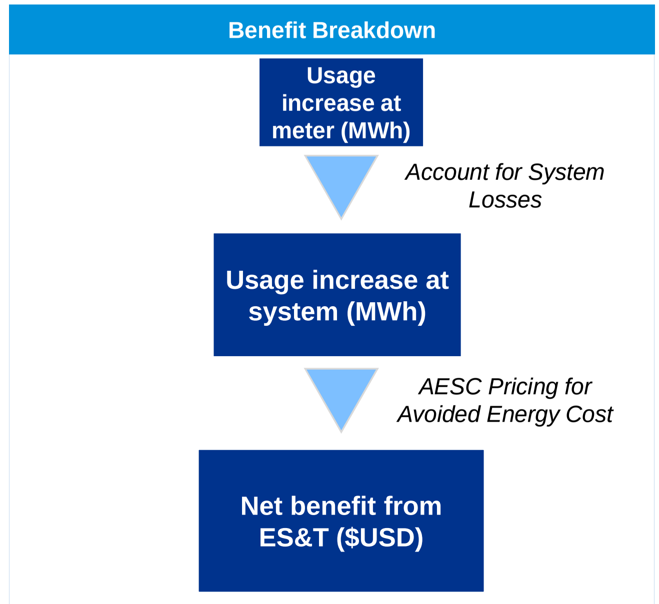
Benefits – Energy Supply and Transmission

Energy Supply & Transmission

- Values the total avoided cost of generating and distributing energy
- In the case of EV charging stations, the program will lead to a greater level of energy usage
- In turn, there is an increase in total energy being supplied, meaning that there is an increase in the cost to both generate and transmit this energy



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Benefits – Avoided REC Costs

Avoided REC Costs

- Despite the increased energy efficiency, there is no qualifying renewable energy being generated by this program
- RECs must be purchased to offset the increased electricity usage
- As a result, this is captured as a negative benefit

Benefit Breakdown

Usage increase at meter (MWh)

÷ 1-System Losses (%)

= Usage increase at system (MWh)

× Avoided REC Cost ($/MWh)

= Total Avoided REC Cost ($USD)

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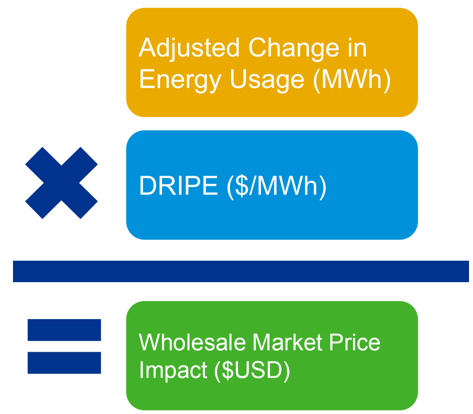
Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, it captures how an increase in the electricity usage impacts the supply and demand
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- Included in RIM test only

Benefit Breakdown



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Benefits – Environmental Costs

Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For transportation, this is calculated by taking the total ICE miles replaced by Electric Vehicles
- This is then multiplied by the average ICE vehicle CO2 emissions rate per mile driven (differs depending on the vehicle)
- The value is then multiplied by the non-embedded cost of CO_2 ($/short ton)
- Calculate the total electricity usage for EVs
- Multiply it by the non-embedded cost of CO2 ($/MWh)
- Net the two values to arrive at the final

Criteria Air Pollutant and Other Environmental Costs

- Attributes value to the avoided emissions of SO2, NOX, and PM2.5
- Uses AESC and EPA prices per ton of avoided emission (by pollutant type)
- Captures the increased environmental and public health benefits of lower particulate emissions
- This captures one of the major benefits of EVs: negligible particulate emissions

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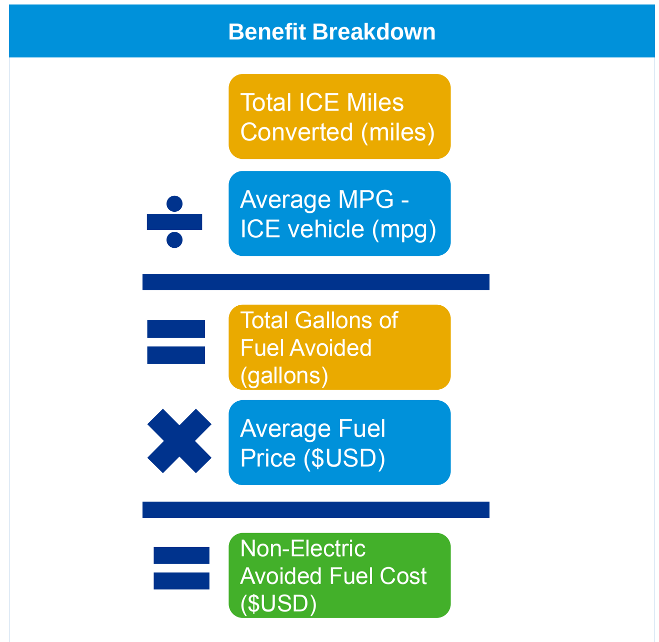
Benefits – Non-Electric Avoided Fuel Costs

Non-Electric Avoided Fuel Costs

- Values the fuel that is no longer consumed due to the adoption of EV's
- Calculated by taking the total ICE miles replaced by Electric Vehicle miles
- Divide by Average MPG for ICE vehicles to get the total gallons of fuel avoided
- Due to the size of the program and the amount of ICE vehicle miles being displaced, this category offers the most significant benefits



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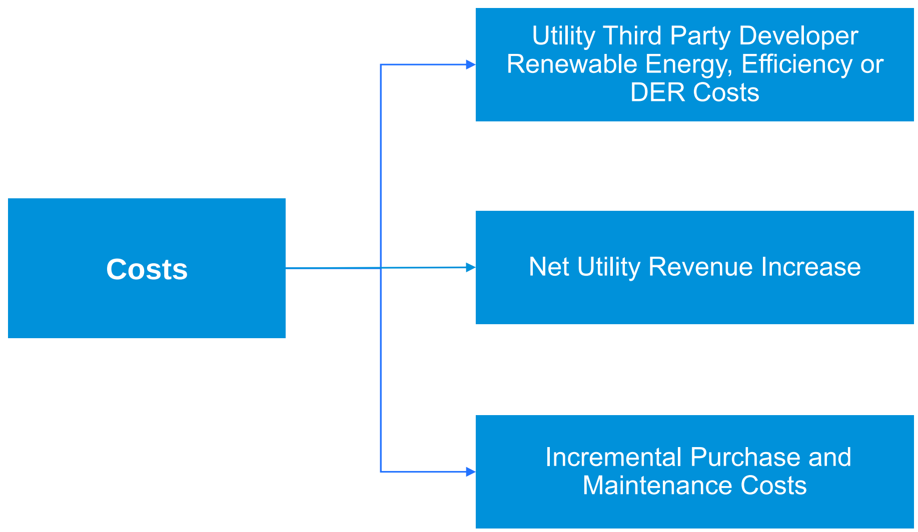
Costs – Overview

Costs Components



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Description of Cost Categories

Utility Third Party Dev. Renewable Energy, Efficiency or DER Costs

Combination of Opex and Capex, less participation payments from station operators

- Differs slightly between Consumer Stations and Fleet & Transit Stations
- Fleet & Transit only have 3 total year of Program Administration Costs
- ~50% of Consumer Stations will be Utility Operated, so a percentage of operating expenditures remain through the life of the program

Net Utility Revenue Increase

Captures National Grid's projected increase in revenue due to the Transportation program

- Uses projected electricity usage for the program and multiplies by the price per kWh
- Only included in the RIM test

Incremental Purchase and Maintenance Costs

Calculates the cost of ownership for consumers

- Incremental purchase price of EV's
- Federal and state tax rebates
- Ongoing maintenance costs for the life of the program

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Results – Transportation

	Electric Vehicles -- Total		
Benefit	Forward Commitment: Capacity Value	$	(1,016,847)
	Energy Supply & Transmission Operating Value of Energy Provided or Saved	$	(2,005,010)
	Avoided Renewable Energy Credit (REC) Cost	$	(199,162)
	Greenhouse Gas (GHG) Externality Costs	$	4,189,624
	Criteria Air Pollutant and Other Environmental Costs	$	999,129
	Non-Electric Avoided Fuel Cost	$	13,567,821
	Economic Development	$	-
		$	-
	Total	**$**	**15,535,555**
Cost	Total Program Administration Costs	$	10,420,428
	Incremental Purchase and Maintenance Cost	$	4,671,444
		$	-
	Total	**$**	**15,091,871**
	BCA Ratio		**1.03**

GHG Externality Cost is very high because ICE vehicles are being replaced by Electric Vehicles with comparatively low carbon emissions

Non-Electric Avoided Fuel Costs is the largest benefit by a considerable margin because gasoline and diesel powered vehicles are converting to EVs

Incremental Purchase and Maintenance Costs is particularly large for transportation because it accounts for the upfront cost of an ICE vehicle versus an EV

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Electric Heat

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Project Overview – Electric Heat

Project Description

- National Grid is offering equipment incentives to encourage eligible customers to convert from delivered fuels and electric resistance heat to more efficient Air-Source Heat Pumps and Ground-Source Heat Pumps
- In accordance with this program, the company will partner with 2 municipalities annually to set community goals and market heat conversions
- Oil and Propane dealer training programs will also occur to support installation and marketing/sales of staff

Modeling Overview

- Assumptions are made concerning the rebate budget, the portfolio and incentive mix, the customer mix, and the allocation of collective incentives to estimate the number of system conversions for each configuration type
- A base heating and cooling system is then selected to develop a "current state" to compare with the forecasted effects of the conversions

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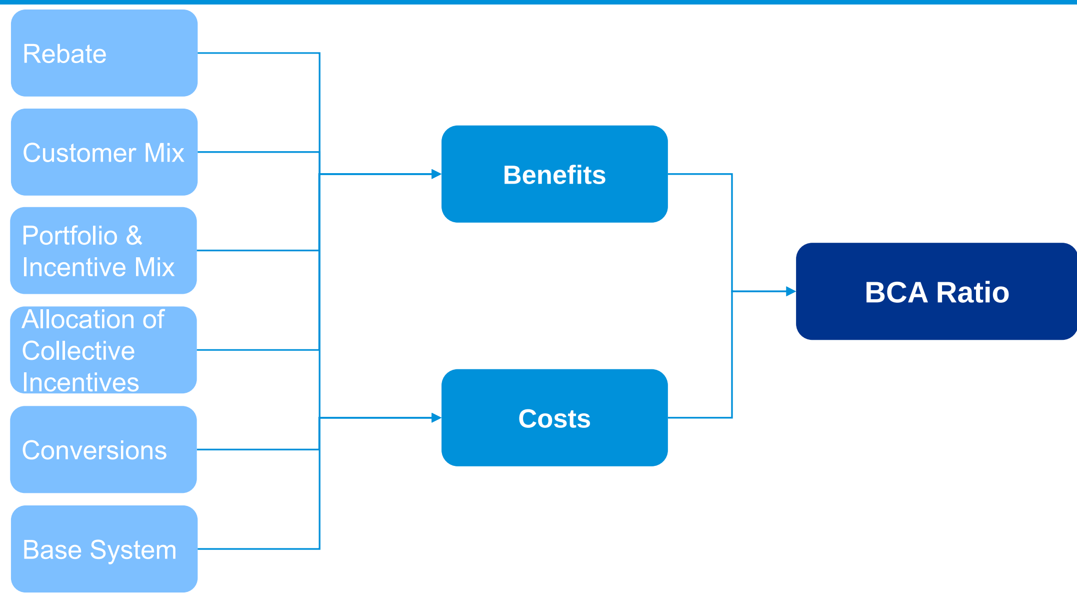
Model Overview

Electric Heat Model Schematic



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Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
Rebate	• The total budget allotted to incentivize both low income and market customers to switch from their base heating and cooling system to an electric heat pump system • The percentage of the total installation costs that customers will receive by participating in the program is also a major driver A larger rebate percentage leads to fewer conversions	*Involved in determining the total number of conversions*	Mackay Miller and RI testimony
Portfolio and Incentive Mix	• The percentage share of the rebate that goes to low income participants versus market participants • The larger share that goes to market participants, the higher the SCT ratio because they are receiving a much lower rebate %		
Conversions	• The total number of systems converted into electric heat systems • The number of system conversions for each system configuration is a function of the rebate specifications, the allocation of collective incentives, the incentive mix and the customer mix	*A key driver of every benefit category*	Calculated based on information from Mackay Miller and RI testimony
Allocation of Collective Incentives	• Determines the share of total incentives that is allocated towards each system type	*Determines which system configurations will see the most conversions*	Mackay Miller and RI testimony
Customer Mix	• The target level of customers that will be low income versus market participants • The higher percentage that are market participants, the higher the SCT ratio because more conversions will occur	*Contributes to the total number of conversions*	Mackay Miller and RI testimony
Base System	• Defines the system that will be converted to electric heat • Provides the model with a baseline for comparison • Options for Base Heat include Fuel Oil, Propane, Natural Gas, and Electricity • Options for Base Cooling include No AC, Window AC, and Central AC	*Impacts the magnitudes of nearly every benefits category*	Mackay Miller and RI testimony

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Control Panel Breakdown

Control Panel - select heating portfolio scenario in table below

Switch key:
Select from Drop-down
Populate Area

Control Panel Description

- The numbers have been saved as default, agreed-upon values with the project teams. The switches only exist to add a degree of flexibility for the user and the program to test scenarios
- **Select from Drop-down**: There is a set list of options that were predetermined by the National Grid team and KPMG
- **Populate Area**: The user can input any number themselves and it will flow through the model

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Key Inputs #1-2 – Customer Mix & Rebate Budget

Sensitivity Analysis of Low-Income Participation & Low-Income Rebate %

% Low-Income Customers	50%
Low-Income Rebate %	100%

Low-Income Rebate (%)

Low-Income Customers (% of Total) 1.12	5%	25%	50%	75%	100%
10%	1.31	1.27	1.26	1.26	1.26
20%	1.35	1.25	1.24	1.23	1.23
30%	1.37	1.24	1.21	1.20	1.20
40%	1.39	1.22	1.18	1.17	1.16
50%	1.41	1.21	1.15	1.13	1.12
60%	1.43	1.19	1.11	1.08	1.06
70%	1.44	1.17	1.06	1.02	0.99
80%	1.45	1.14	1.00	0.93	0.89
90%	1.47	1.11	0.93	0.82	0.77
100%	1.48	1.09	0.85	0.71	0.63

Sensitivity Analysis of Low-Income Participation & Rebate Total

% Low-Income Customers	50%
Total Rebate Budget	708,750

Total Rebate ($)

Low-Income Customers (% of Total) 1.12	500,000	708,750	1,000,000	1,250,000	1,500,000
10%	1.16	1.26	1.34	1.38	1.41
20%	1.13	1.23	1.31	1.36	1.39
30%	1.09	1.20	1.29	1.34	1.37
40%	1.05	1.16	1.26	1.31	1.35
50%	1.00	1.12	1.22	1.28	1.32
60%	0.94	1.06	1.17	1.24	1.28
70%	0.87	0.99	1.11	1.18	1.23
80%	0.78	0.89	1.02	1.10	1.16
90%	0.66	0.77	0.90	0.98	1.05
100%	0.52	0.63	0.73	0.81	0.87

Customer Mix: Input the target percentage of customers that are low-income participants. Low-income recipients receive 100% installation rebates. Therefore, the higher the percentage of low income customers, the lower the SCT.

Rebate Budget: Input the total rebate budget. The sensitivity table shows that a larger rebate budget generally leads to a higher SCT because it will drive more conversions.

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Key Inputs #1,3,4 – Incentives & Rebate %

Portfolio & Incentive Mix

Customer	% of Total
Low-Income	50%
Market	50%
Total	100%

Portfolio and Incentive Mix: Input the allocation percentage of the rebate budget between the Low-income and Market participants.

Allocation of Collected Incentives

System Type	Low-Income	Market
ASHP 3 ton	50%	50%
ASHP 5 ton	0%	0%
GSHP Horizontal Loop 4 ton	50%	50%
GSHP Vertical Loop 82 ton	0%	0%
Total	100%	100%
Check (Sum equal to 100%)	Y	Y

Allocation of Collective Incentives: After selecting the customer segment allocation, the user must input the percentage of the budget the flows toward each type of electric heating system. This drives the model's system adoption logic.

Rebate by Customer Type and System

Customer	System	Tons (per system)	Cost ($/ton)	Rebate ($/ton)	Rebate %
Low-Income	ASHP 3 ton	3	3,200.00	3,200.00	100%
	ASHP 5 ton	5	3,381.00	3,381.00	100%
	GSHP Horizontal Loop 4 ton	4	7,988.24	7,988.24	100%
Market	ASHP 3 ton	3	3,200.00	500.00	16%
	ASHP 5 ton	5	3,381.00	500.00	15%
	GSHP Horizontal Loop 4 ton	4	7,988.24	750.00	9%

Rebate %: Input the rebate percentage for each system type and customer segment to generate economics.

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Key Inputs #5,6 – Base System & Conversions

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System Technology Selections

Technology Type	Base Heating	Base Cooling	New System Type	Incentive Allocated (y/n)	2018	2019	2020	2021	2022	Total Converted
					Progression Schedule (number of conversions)					
Type A	Fuel Oil	No AC	ASHP 3 ton	Yes	39.00	45.00	50.00	-	-	134.00
Type B	Fuel Oil	No AC	GSHP Horizontal Loop 4 ton	Yes	18.00	20.00	24.00	-	-	62.00
Type C	Fuel Oil	No AC	GSHP Vertical Loop 82 ton	N/A	-	1.00	-	-	-	1.00
Type D	Fuel Oil	No AC	ASHP 5 ton	No	-	-	-	-	-	-
			Total		57.00	66.00	74.00	-	-	197.00

Base System: Select the assumed base system that the customer is switching over from. This will impact the total magnitude of the conversions across the benefits categories

Conversions: The number of conversions from the base system to the electric heating systems is a function of all the other key inputs. After making the previous specifications, the number of conversions for each system type will be determined

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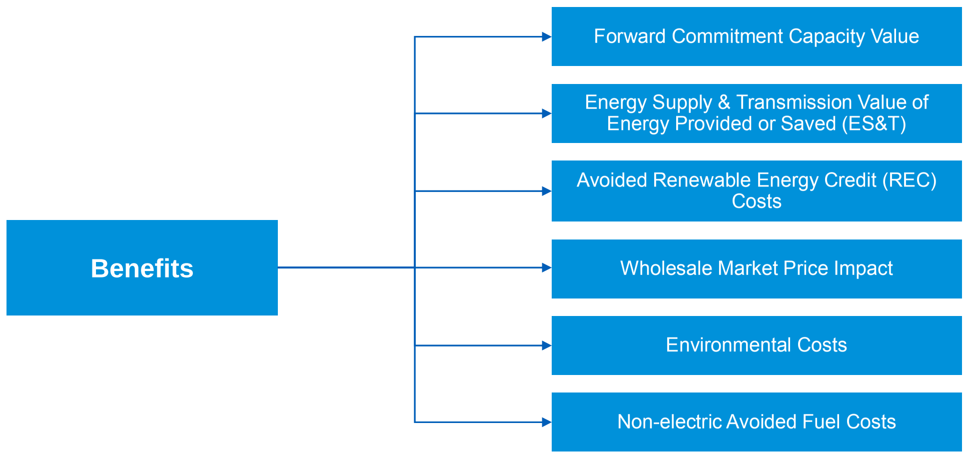
Benefits – Overview

Benefits Components



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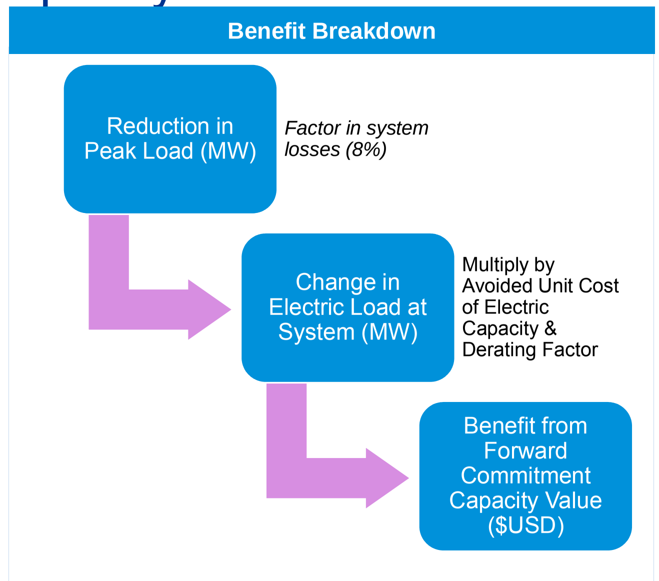
Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because you must bid into the forward capacity market 4 years in advance
- In the case of Electric Heat, the program will lead to an overall decrease in the load demands of the system
- Although the majority of the participants will switch from fossil fuel systems to electric heat pumps, some will switch from highly inefficient electric systems
- This switch will offset any increased load from the heat pumps and yield a net benefit for the program



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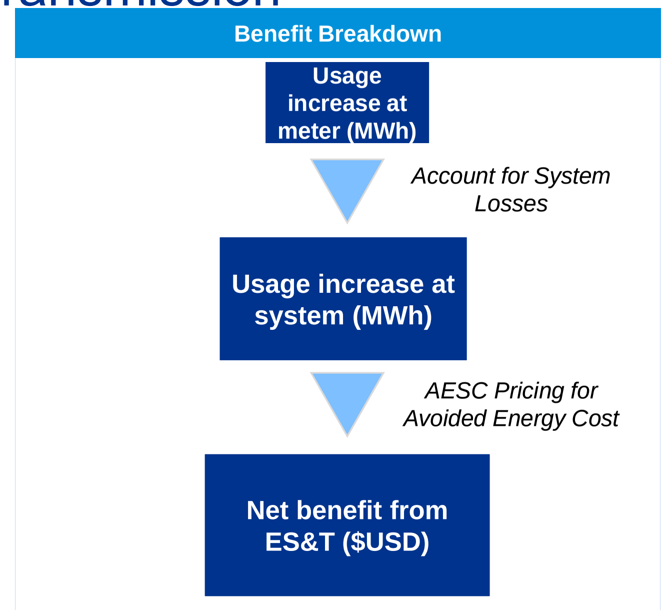
Benefits – Energy Supply and Transmission

Energy Supply & Transmission

- Values the total avoided cost of generating and distributing energy
- The electric heat program will lead to a greater level of total electricity usage
- In turn, there is an increase in the cost to generate and transmit this energy



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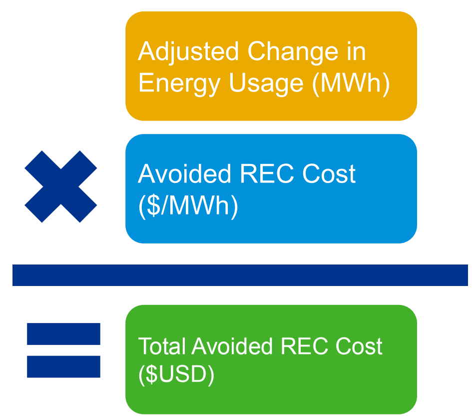
Benefits – Avoided REC Costs

Avoided REC Costs

- Despite a large increase in energy efficiency, there is no qualifying renewable energy being generated by this program
- RECs must be purchased to offset the increased electricity usage
- As a result, this is captured as a negative benefit

Benefit Breakdown



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Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, this value captures how an increase in the electricity usage impacts real-world supply and demand
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- Only included in the RIM test

Benefit Breakdown

Adjusted Change in Energy Usage (MWh)

× DRIPE ($/MWh)

= Wholesale Market Price Impact ($USD)

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Benefits – Environmental Costs

Greenhouse Gas Externality Costs

- Multiplies the increased electricity usage from the heat pumps by the non-embedded CO2 cost to get the Electricity Added Carbon Benefits
- Multiplies the CO2 emissions per unit by the fossil fuel usage reduction

  -Multiply this number by the non-embedded CO2 cost to Fossil Fuel Carbon Benefits
- Take the net value of Fossil Fuel Carbon Benefits and Electricity Added Carbon Benefits

Criteria Air Pollutant and Other Environmental Costs

- Values the net avoided emissions by switching from a fossil fuel system to an electric heat system
- Uses AESC and EPA prices per ton of avoided emissions
- Captures the increased environmental and public health benefits of lower particulate emissions

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Benefits – Non-Electric Avoided Fuel Costs

Non-Electric Avoided Fuel Costs

- Values the fuel not consumed due to the adoption of the electric heating system
- Multiplies the reduction in consumption by the average price of consumption ($/MMBTU)
- This category captures the majority of the benefits of the electric heating system conversions

Benefit Breakdown

Base Fuel Consumption Cost ($USD)

× Base Fuel Reduced Consumption ($USD)

= Non-Electric Avoided Fuel Cost ($USD)

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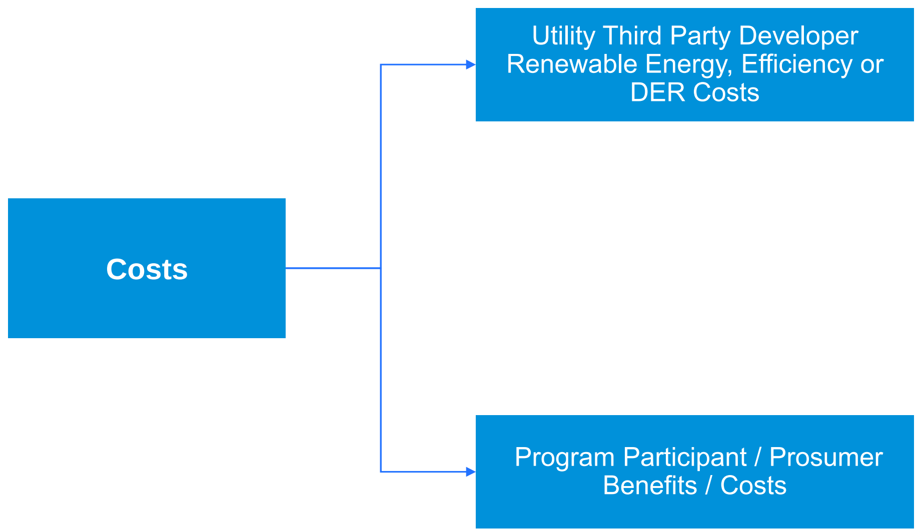
Costs – Overview

Costs Components



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Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Incentive costs and program administration costs

- Incentives are for system installations and community programs
- Program administration costs are for community programs and oil dealer training & support

Program Participant / Prosumer Benefits / Costs

Captures participant's net installation costs

- Uses the total installation cost and subtracts any applicable incentives

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Electric Heat – Results

EH - BCA Summary

Societal Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	0	$	-
	Greenhouse Gas (GHG) Externality Costs	$	527,088
	Criteria Air Pollutant and Other Environmental Costs	$	222
	Non-Electric Avoided Fuel Cost	$	4,162,394
	Economic Development	$	-
	0	$	-
		$	**3,745,721**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or	$	1,073,830
	Program Participant / Prosumer Benefits / Costs	$	2,275,503
		$	**3,349,332**
	BCA Ratio		**1.12**

Non-Electric Avoided Fuel Costs is the largest benefit by a considerable margin because the program results in people switching from a fuel-based heating system to an electric heat pump. This switch generates savings from avoided purchase of fuel oil, natural gas, or propane.

Electric Heat Pumps are much more energy efficient than the base systems, so the major cost to market participants is **installation costs**. This cost category can change based on conversion count and the customer mix.

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Solar

Reference Document

November 2017

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Project Overview – Solar

Project Description

- National Grid will be constructing solar generation units at three different sites. One 0.25 MW site will be built in 2018, one 0.5 MW site will be built in 2019, and one 1.5 MW site will be built in 2020
- The benefits from these respective sites will come on line one year after they are built
- The two smaller systems are intended to be canopies, and the larger to be a simple rooftop or fixed ground installation (e.g., no advancing tracking hardware/software is planned)

Modeling Overview

- Total System Capacity and Capacity Factor are used to estimate the total annual energy output from solar generation and derive an Adjusted Peak Load
- These numbers are then used with AESC prices to value the capacity and usage benefits from the solar program

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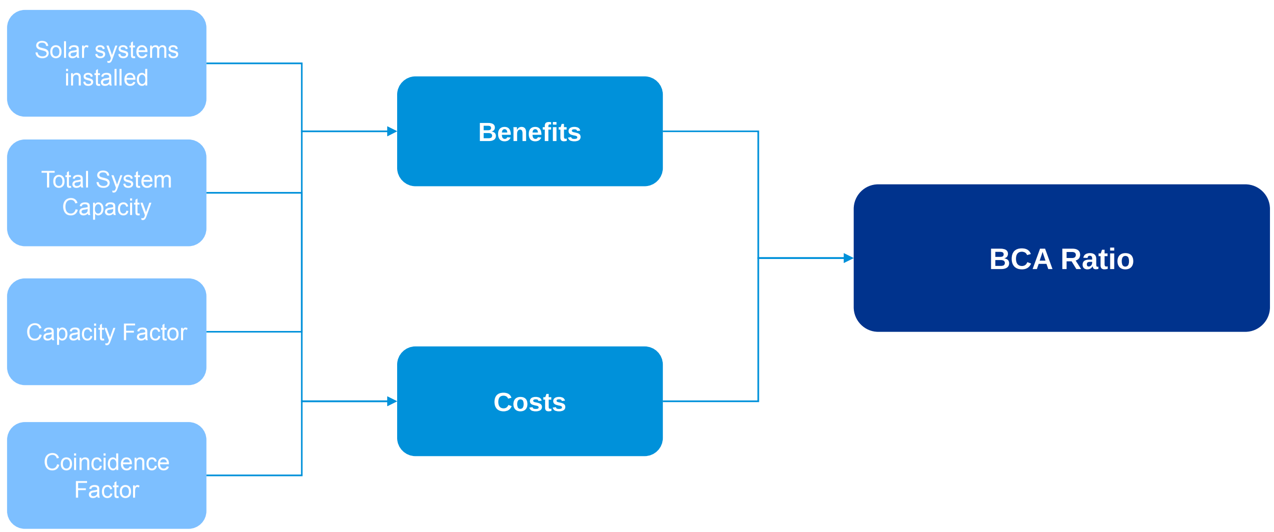
Model Overview

Solar Model Schematic



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Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
Systems Built	• The total number of systems built by National Grid and their respective years. • NG is building one 0.25 MW solar canopy in 2018, one 0.5 MW solar canopy in 2019, and a larger 1.5 MW solar unit in 2020	*Used to determine the peak site capacity and the total solar energy generation in a given year*	Calculated based on RI testimony
Total System Capacity	• The peak capacity of the total solar generation system • The sites come on line and start accruing benefits the year after they are built		
Capacity Factor	• The ratio of actual power generation over a year divided by installed capacity • The capacity factor suggests that, over the course of a year, the system is generating energy at 16.1% of its peak operating capacity • Solar has a relatively low capacity factor in comparison to other forms of energy generation	*Used with total system capacity to estimate the average annual output from solar generation*	PV Watts
System Coincidence Factor	• A measure of solar generation capacity during the time of peak energy demand • The amount of energy that it generates during this period informs how much it reduces the peak load of the system • Estimated to be 28.1% • This input is largely determined by system site selection, panel orientation, and the climate of the region – all inputs contributing to the amount of sunlight that gets captured	*Used to calculate the Benefit from Forward Commitment Capacity Value*	Confirmed with project team

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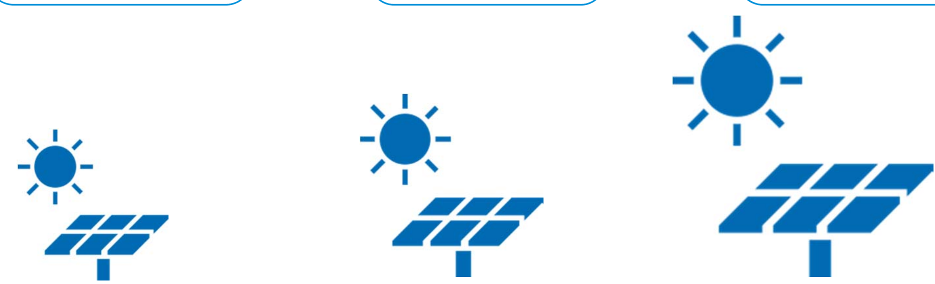
Key Inputs #1/2 – Systems Installed & Capacity

- ❑ National Grid will undergo construction of 3 solar sites from 2018 to 2020
- ❑ Over this period, the total system capacity will increase from 0.25 MW to 2.25 MW
- ❑ These systems all have a useful life of 25 years

2018
- System Type A: 0.25 MW

2019
- System Type B: 0.5 MW

2020
- System Type C: 1.5 MW



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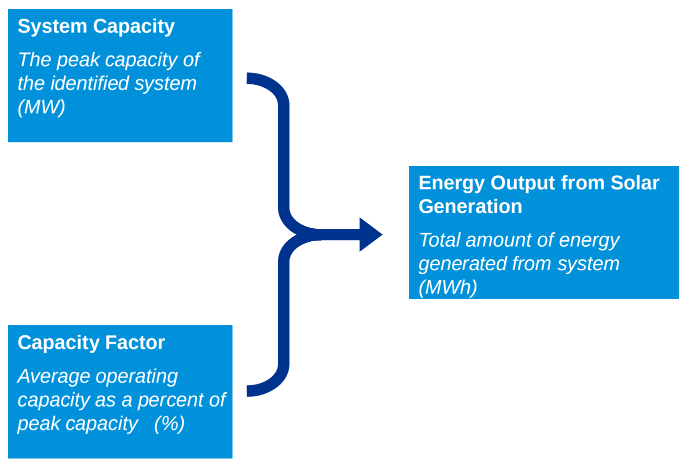
Key Input #3 – Capacity Factor

Input Breakdown



- The capacity factor is a descriptive statistic characterizing the average operating capacity of the systems in question
- This is expressed as a percentage of the peak system capacity
- This is an important metric because it can be used to determine which locations and sites are most suitable for solar
- Used in combination with peak system capacity, it is possible to estimate the average energy output from solar generation

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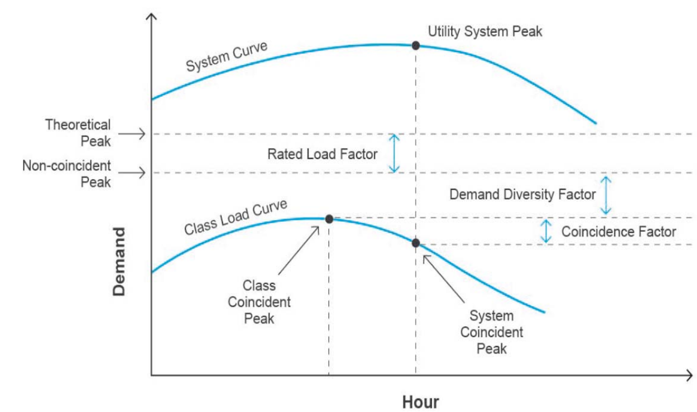
Key Input #4 – Coincidence Factor

- The System Coincidence Factor for solar is a measure of the system operating capacity during the utility system peak demand
- It measures how much the peak system load overlaps with periods of strong sunlight absorption
- A key driver for this factor is the amount of sunlight available for conversion into energy
- Used in the calculation for the Forward Commitment Capacity Value

Illustration of System Coincidence Factor



Source: NREL – Peak Demand and Time-Differentiated Energy Savings Cross-Cutting Protocols

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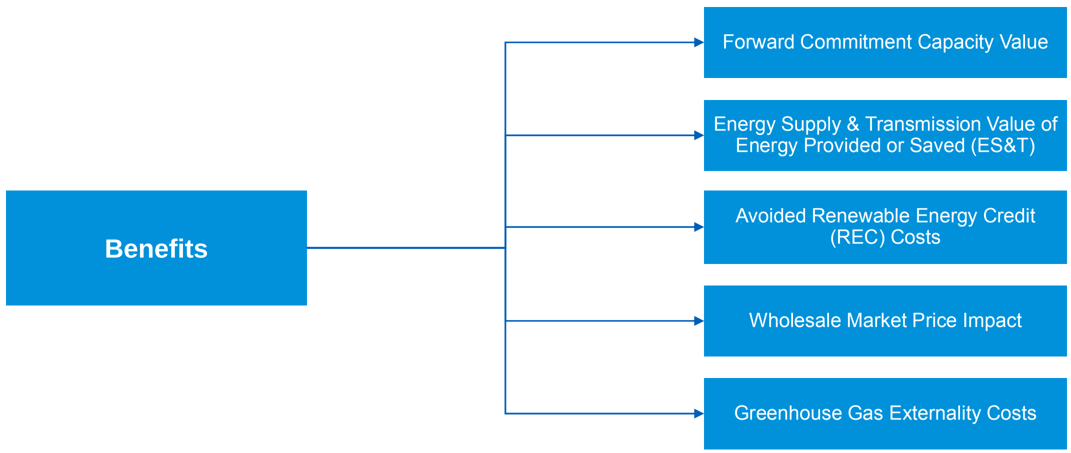
Benefits Overview

Benefits Components



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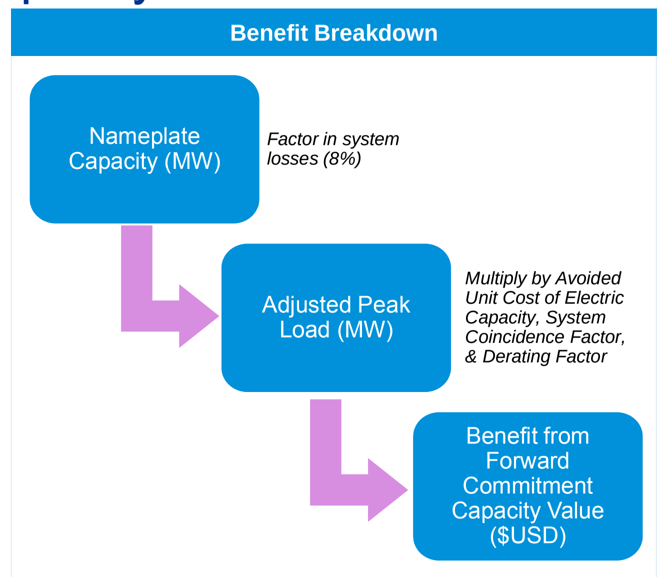
Benefit – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because of requirement to bid into the forward capacity market 4 years in advance
- Increased energy generation from Solar helps to lessen the total load demand on the system
- This provides a large benefit for the Solar BCA



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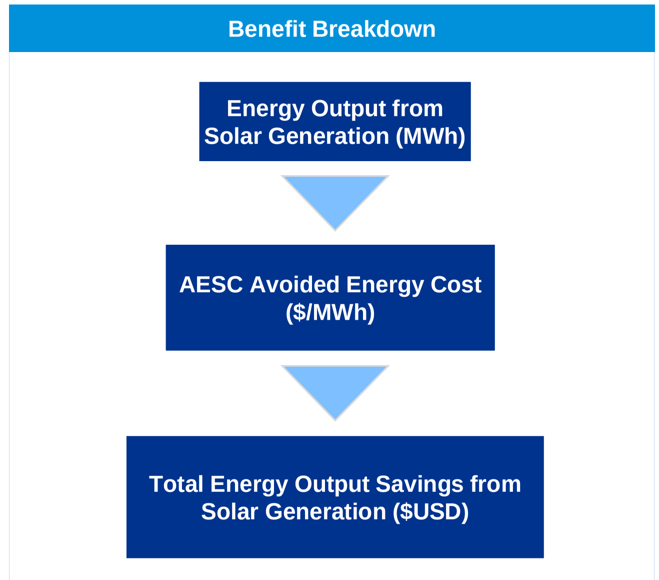
Benefit – Energy Supply & Transmission

Energy Supply & Transmission

- Values the total avoided cost of generating and distributing energy
- In the case of Solar generation, the program will reduce the amount of energy that needs to be generated and supplied at the system level
- In turn, the Solar program is attributed the value of this avoided generation and transmission



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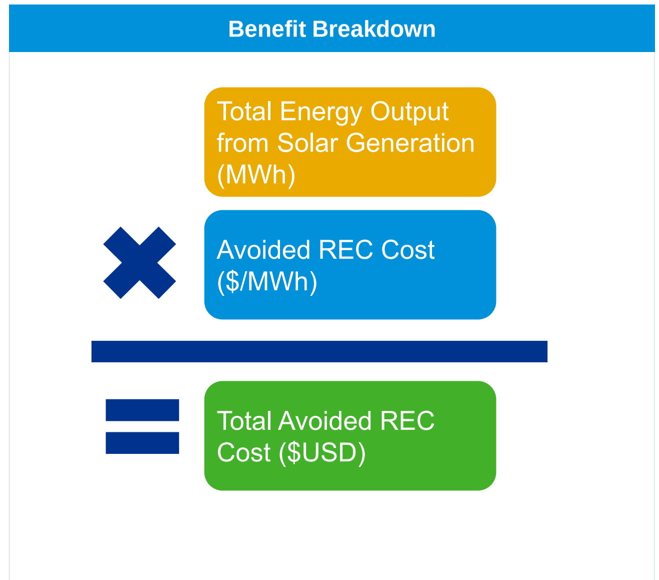
Benefit – Avoided REC Costs

Avoided REC Costs

- For every MWh of power generated by the solar systems, National Grid will receive 1 REC
- These provide tangible value to the company because each REC accrued from generation is one that they can avoid purchasing later (or can offset existing obligations)



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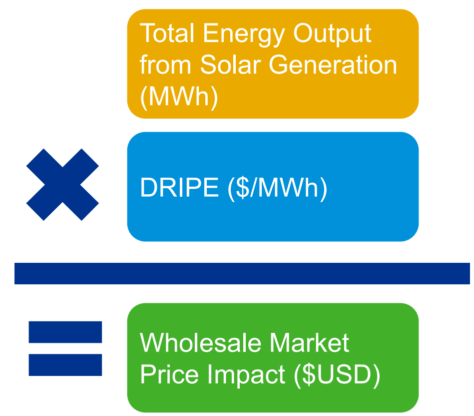
Benefit – Wholesale Market Price Impact

Wholesale Market Price Impact

- ❑ Values the price changes in the market that are ***directly attributable to the program itself***
- ❑ For example, it captures how an increase in the electricity usage impacts the supply and demand
  - Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- — Only included in the RIM test

Benefit Breakdown



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Benefit – GHG Externality Cost

Avoided Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For Solar, the resulting energy output from solar generation is assumed to displace the same amount of energy at the system level
- This results in a switch from an emissions generating energy source to a "zero" emissions source
- Therefore, National Grid is avoiding GHG emissions that would have occurred if not for increased solar generation

Benefit Breakdown

Total Energy Output from Solar Generation (MWh)

× Non-embedded CO2 cost ($/MWh)

= Greenhouse Gas Externality Cost ($USD)

Source: NREL; Profim

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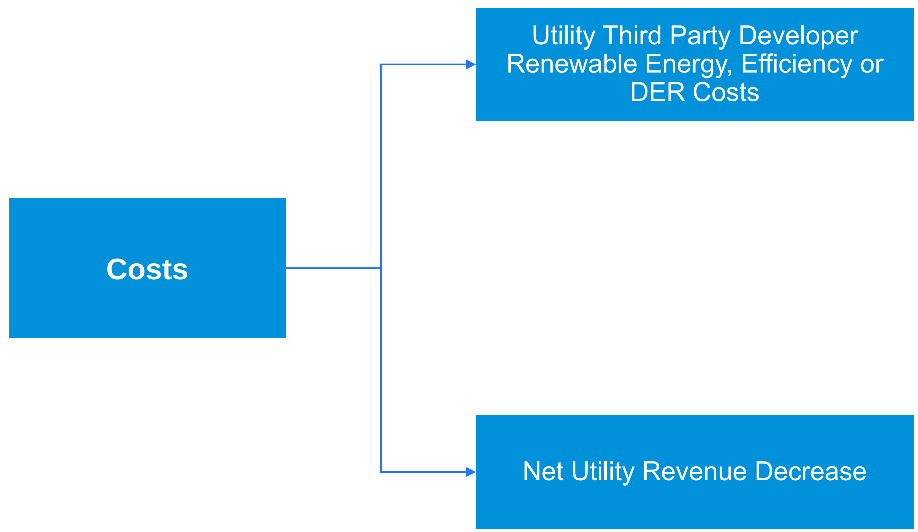
Costs Overview

Costs Components



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Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Combination of Capex and Opex Sub-total, less any relevant tax incentives

- Capex refers to the direct cost of building the sites
- Opex Sub-total includes the ongoing site maintenance costs as well as the inverter leases
- Tax incentives refer to the ITC tax incentive as well as the R&D tax incentive

Net Utility Revenue Decrease

Captures National Grid's projected decrease in revenue attributable to the program

- Accounts for the fact that the utility will not be receiving charges from electricity generation
- This cost is only included in the RIM test

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Solar – Results

The greatest benefit comes from the avoided generation and transmission of energy.

Solar panels will be replacing an energy source that most often emits far greater amounts of greenhouse gases.

Societal Cost Test

RI Solar BCA

	Solar - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	1,204,029
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	3,022,542
	Avoided Renewable Energy Credit (REC) Cost	$	213,002
		$	-
	Greenhouse Gas (GHG) Externality Costs	$	1,605,107
	Non-Electric Avoided Fuel Cost	$	-
	Economic Development	$	-
		$	-
		$	**6,044,680**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	7,093,687
		$	-
		$	**7,093,687**

BCA Ratio **0.85**

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Energy Storage

Reference Document

November 2017

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Project Overview – Energy Storage

Project Description

- National Grid proposes constructing 2 energy storage batteries: one ~0.50 MWh battery will be built in 2018, and another ~0.75 MWh battery will be built in 2019
- The storage systems will begin providing benefits one year after they are built
- They will be deployed in areas that maximize the benefits to the transmission system and to customers/partners
- National Grid's preference is to work with a local partner to share in both the costs and benefits and to maximize engagement with the broader community whenever possible

Modeling Overview

- Given rated energy, the difference is calculated between energy displaced from Off-peak to On-peak over a single full charging cycle
- An assumption is then made regarding number of cycles per year as well as the round trip efficiency loss
- Using these factors, it is possible to forecast the total energy displaced annually and the total energy charged annually
- These numbers – along with AESC & ISO-NE market prices – are utilized to calculate usage-related benefits.
- In order to capture the increased capacity benefits, an assumed ratio of capacity to energy can be used to calculate the reduction in the system's peak load

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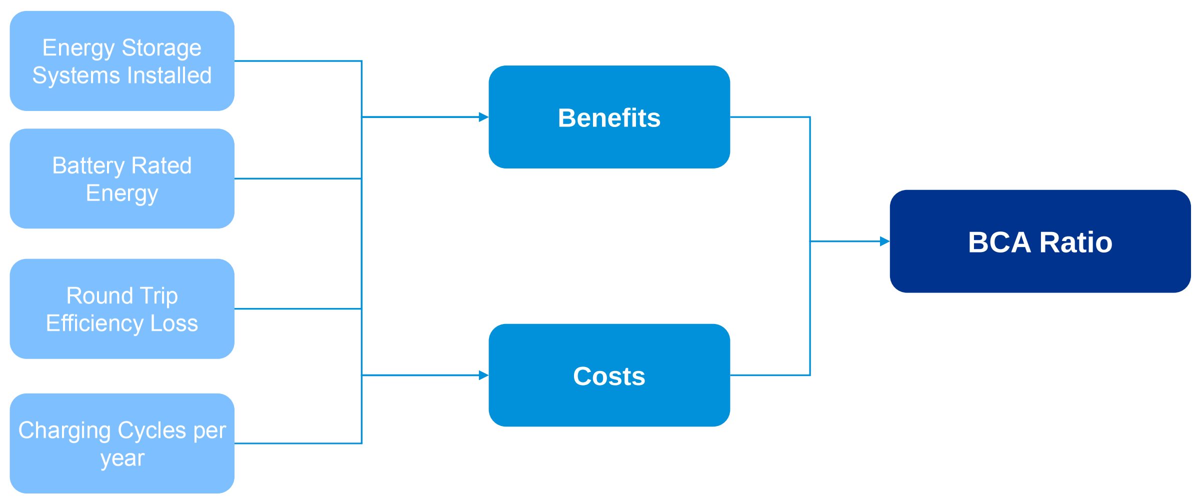
Model Overview

Energy Storage Model Schematic



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Key Inputs

Key Inputs	Definition	Model Usage	Sources
Energy Storage Systems Built	• The total number of systems built by National Grid and their respective years. • NG is building one 0.5 MW battery in 2018, and one 0.75 MW battery in 2019	*Used in order to calculate the amount of energy displaced from On-peak to Off-peak as well as the change in energy load*	RI testimony - October 3rd 2017 -
Battery Rated Energy	• The total amount of energy that the batteries can store • The batteries are assumed to come online and start accruing benefits the year after they are built	*Used in order to calculate the amount of energy displaced from On-peak to Off-peak as well as the change in energy load*	RI testimony - October 3rd 2017 -
Round Trip Efficiency Loss	• The amount of energy lost when converting from one system to another • Assumed round trip efficiency loss was 10%, meaning that through the process of charging and discharging the batteries lose about 10% of usable energy	*Used in order to calculate the total energy usage increase which is used in all usage related benefits*	Kenmore Energy Storage Project File
Charging Cycles per Year	• The amount of times a battery charges and discharges annually • Assuming 1 discharge per day, 5 days per week	*Used to calculate the total energy displaced and charged annually*	Lazard Levelized Cost of Storage 2.0 Study

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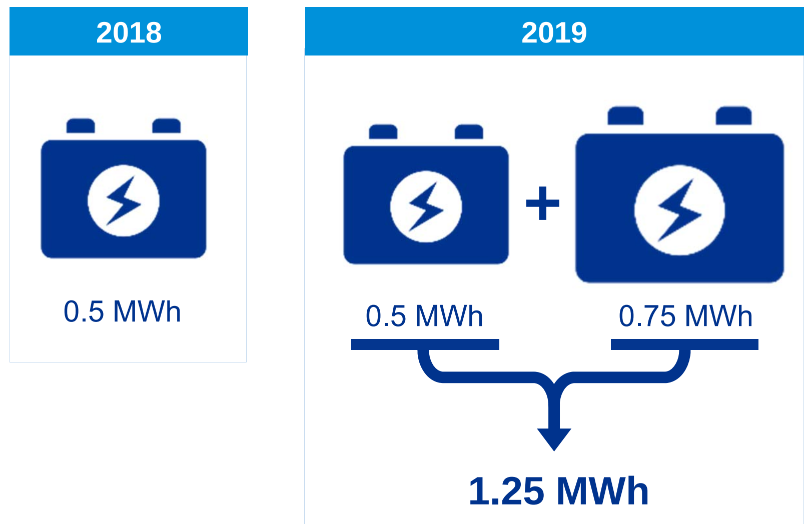
Key Input #1-2 – System Builds & Total Energy

- ❑ National Grid proposes the construction of 2 energy storage systems in 2018 and 2019
- ❑ Over this period, the total storage of the system increases from 0.5 MWh to 1.25 MWh
- ❑ Systems are assumed to have a useful life of 12 years
- ❑ Benefits begin accruing in the year following the system build



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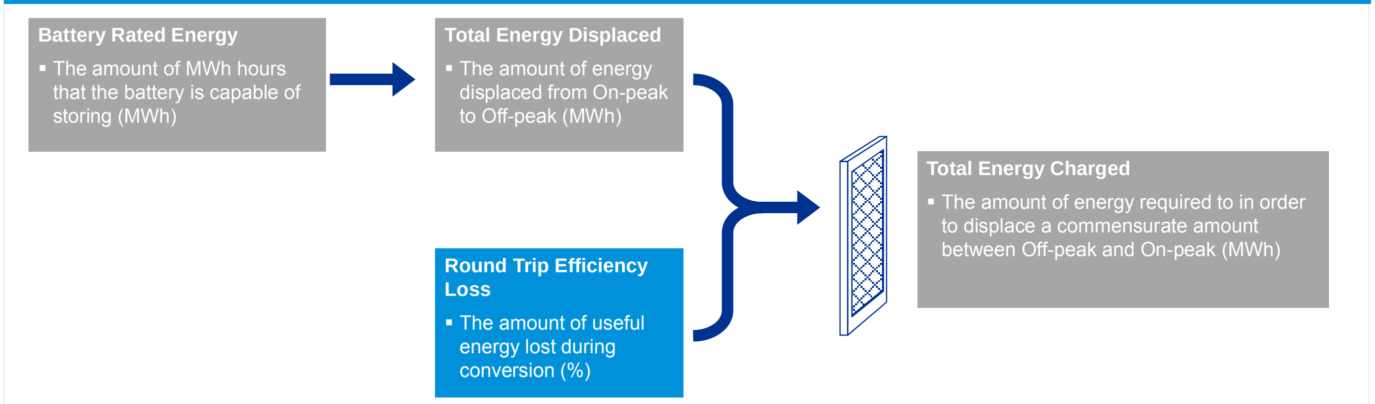
Key Input #3 – Round Trip Efficiency Loss

Input Breakdown



- Round trip efficiency loss refers to the ratio of energy stored to energy retrieved
- 10% round trip efficiency loss suggests that if you charge 1.11 MWh Off-peak, ~1 MWh of energy if effectively displaced
- Battery efficiency is quickly approaching (and in some cases surpassing) 90% for standard lithium-ion configurations

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Key Input #4 – Charging Cycles Per Year

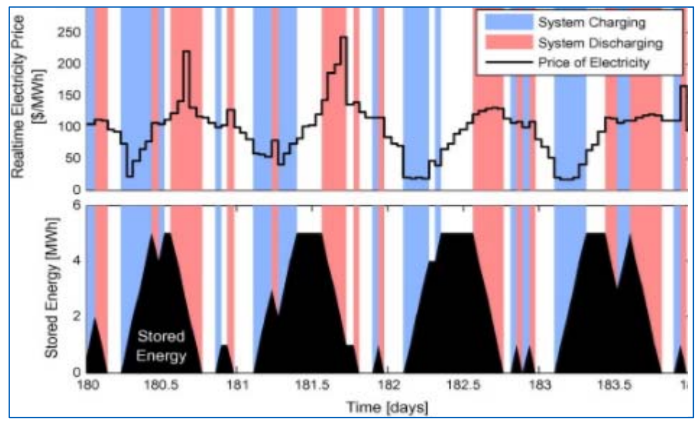
- The total number of charges and discharges annually
- Adjusts energy usage numbers from per cycle basis to an annual basis
- Assumes 1 charge per day, 5 days per week

Charge/Discharge Components

Total Energy Displaced (per cycle) (MWh)
Charging Cycles per Year (#)
System Losses (%)
Depth of Charged (%)
→ Total Energy Displaced Annually (MWh)

Total Energy Charged (per cycle) (MWh)
Charging Cycles per Year (#)
System Losses (%)
Depth of Charge (%)
→ Total Energy Charged Annually (MWh)

Sample Battery Dispatch Profile



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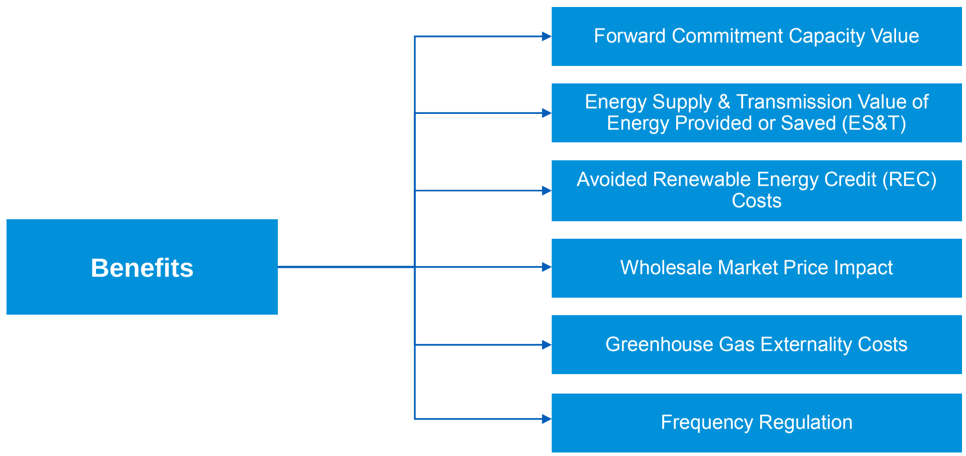
Benefits – Overview

Benefits Components



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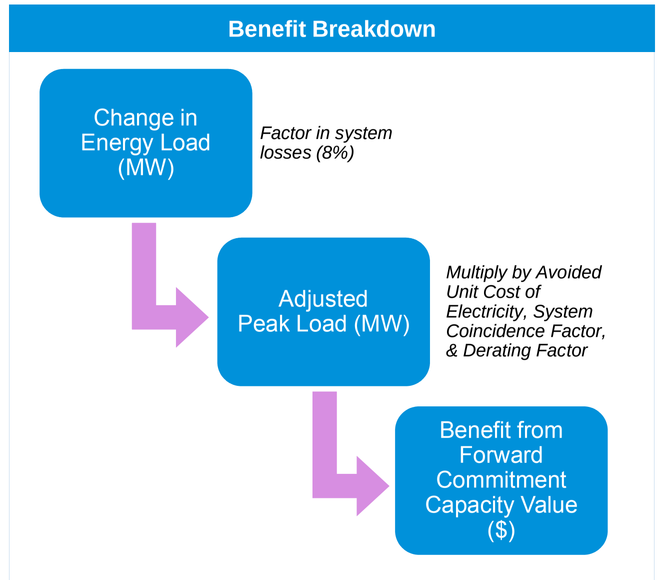
Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- ❑ Values the increase or decrease in the total energy demand attributable to the program
- ❑ Numbers are lagged by four years because you must bid into the forward capacity market 4 years in advance (in accordance with AESC guidance)
- ❑ The displaced energy from charging Off-peak and discharging On-peak supports the grid during times of peak load
- ❑ Capacity is a major benefit of Energy Storage in most jurisdictions, though payment mechanisms vary and are currently in a state of flux



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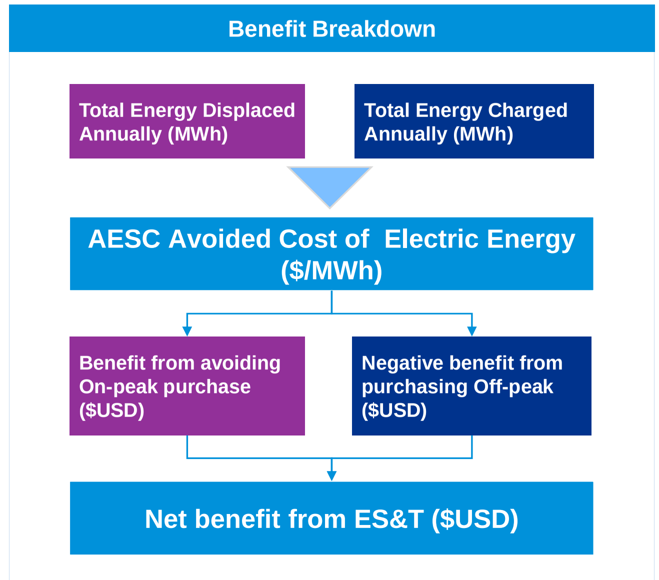
Benefits – Energy Supply & Transmission

Energy Supply & Transmission

- Attributes a monetary value to the total avoided cost of generating and distributing energy
- In the case of Energy Storage, the batteries will charge energy Off-peak and discharge On-peak
- This has a major benefit for capacity but also increases total energy usage due to efficiency loss
- However, the On-peak prices are much higher than Off-peak price, so ES&T becomes a net positive benefit for Energy Storage



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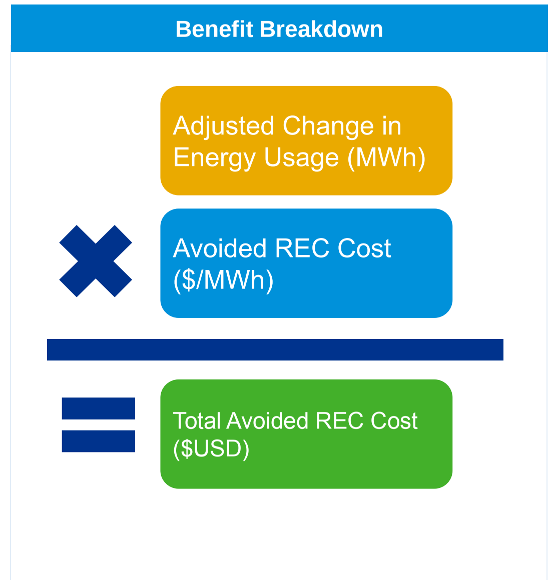
Benefits – Avoided REC Costs

Avoided REC Costs

- For each MWh of power generated from a renewable energy source, National Grid receives 1 REC
- The Energy Storage program has a negative Avoided REC Cost because they are increasing energy usage and have to purchase RECs to offset usage increase



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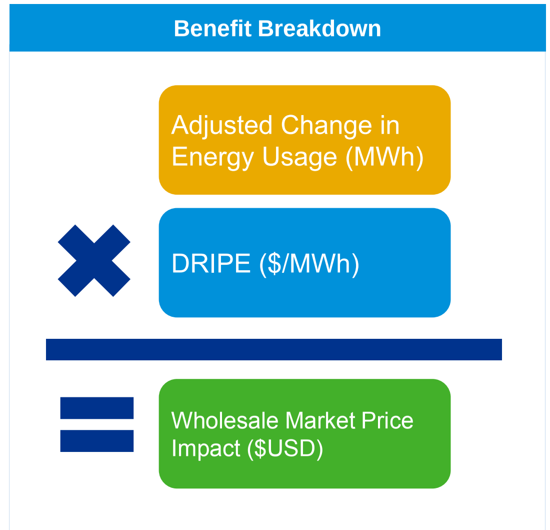
Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, it captures how an increase in the electricity usage impacts actual market supply and demand, and eventually equilibrium prices
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the resulting increase in electricity usage



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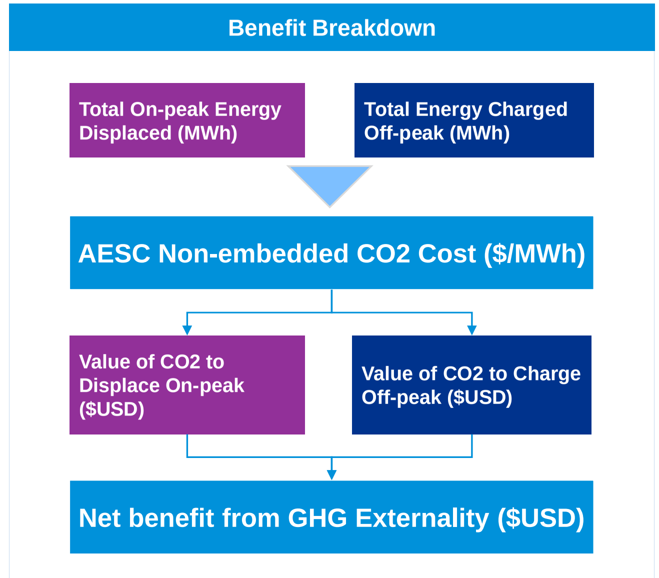
Benefits – GHG Externality Costs

Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For Energy Storage, estimates are made for the change in energy usage by subtracting the total energy charged from the total energy displaced
  - This yields a usage increase for energy storage due to efficiency loss
  - However, there is an emissions benefit to using Off-peak energy versus On-peak energy
- The increased energy usage outweighs the benefit to charging Off-peak
- As a result, Greenhouse Gas Externality Cost is a negative benefit in this storage case



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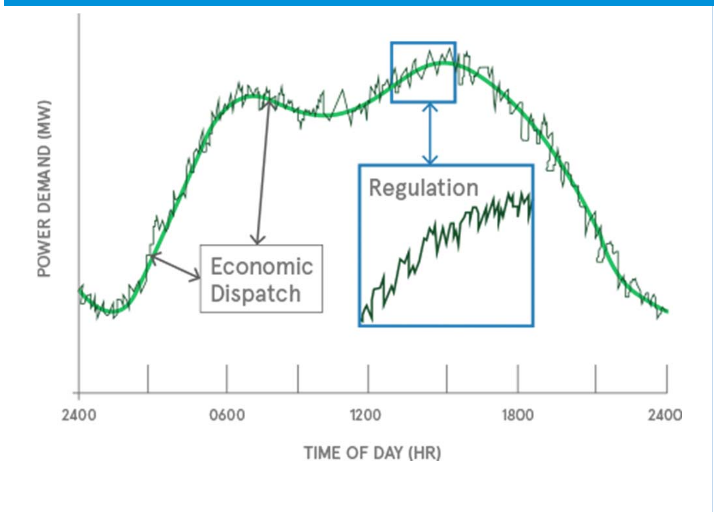
Benefits – Frequency Regulation

Frequency Regulation

- Frequency regulation is the second-by-second power adjustments that take place to maintain grid stability
- In ISO NE, participants respond to ISO signals every 4 seconds to increase or decrease their energy output
- This process helps to balance energy supply levels against momentary demand fluctuations
- Frequency regulation market participants are selected by ISO-NE dispatch algorithm and then are credited for (1) regulation capacity and (2) regulation service

Illustrative Example



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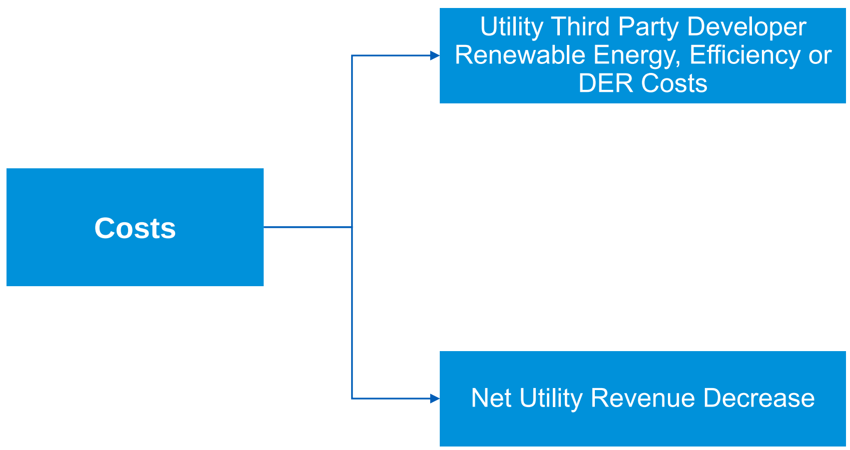
Costs – Overview

Costs Components



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Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Culmination of Capex and Opex Subtotal, less any relevant tax incentives and cost sharing with a potential partner

- ❑ Capex refers to the direct cost of constructing and installing the batteries
- ❑ Opex Sub-total includes the ongoing site maintenance costs as well as the lease charge
- ❑ R&D tax credit refers to a rebate for a certain percentage of Opex

Net Utility Revenue Decrease

Captures National Grid's projected decrease in revenue attributable to the program

- ❑ Accounts for the increased revenue Off-peak and the decreased revenue On-peak
- ❑ This results in an overall revenue decrease due to the higher prices during On-peak hours
- ❑ Only included in the RIM test

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Energy Storage – Results

ES - BCA Summary

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Societal Cost Test

RI Energy Storage BCA

	Energy Storage - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	889,173
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (	$	139,264
	Avoided Renewable Energy Credit (REC) Cost	$	(2,859)
		$	-
	Greenhouse Gas (GHG) Externality Costs	$	(6,674)
	Economic Development	$	-
		$	-
		$	**1,018,904**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	2,260,660
		$	**2,260,660**
			0.45

The majority of benefits come from the increased capacity offered by the batteries.

Charging during off-peak and displacing avoiding elevated on-peak pricing is an energy-storage specific benefit.

Appendix 2.2

Economic Development

APPENDIX 2.2: ECONOMIC DEVELOPMENT

For reference, the Company is including a detailed description of the economic development benefits estimated by the Company. As noted in Chapter Two, these benefits are not included in the Company's BCA cost tests for several reasons.

In total, National Grid plans to spend $206 million through 2021 on planning, constructing, installing and implementing five electric utility projects: company-owned solar, storage, electric vehicle service equipment, electric heat pump conversions, and AMI. AMI accounts for the vast majority of the spending, $181 million or 87%.

The impact on Rhode Island Gross Domestic Product (GDP) is highlighted below because this economic development benefit was not included in the Benefit Cost Analyses, but the cost of planning, constructing, installing and implementing the projects was included. Planned investment spending on the projects is expected to increase local Rhode Island demand and raise GDP by $67 million through 2021. Again, the majority of this impact, $48 million, is attributable to AMI. Solar, storage, electric vehicle service equipment and heat pump conversions add $19 million to Rhode Island GDP through 2021.

Table 2.2-1: Total Investment Spending and Economic Impacts by Project Planning through Construction Phase (2018-2021) in Rhode Island

Rhode Island Investment Proposal
Total Investment Spending and Economic Impacts by Project
Planning through Construction Phase (2018-2021)

Year	2018	2019	2020	2021	Sum
Spending Plan (Labor & Materials)					
Company-Owned Solar	$1.3	$2.6	$5.4	$0.2	$9.5
Company-Owned Storage	$0.9	$1.4	$0.0	$0.0	$2.4
Electric Vehicle Service Equipment (EVSE)	$1.4	$2.4	$5.3	$0.0	$9.1
Electric Heat Pump Conversions	$1.3	$2.1	$1.6	$0.0	$5.0
AMI Meters*	$0.0	$32.6	$62.3	$85.8	$180.6
Total	$5.0	$41.0	$74.6	$86.0	$206.6
Impact on RI GDP ($m)	**2018**	**2019**	**2020**	**2021**	**Sum**
Company-Owned Solar	$0.7	$1.5	$3.2	$0.5	**$6.0**
Company-Owned Storage	$0.5	$0.8	$0.1	$0.1	**$1.5**
Electric Vehicle Service Equipment (EVSE)	$1.1	$2.3	$5.4	$0.0	**$8.7**
Electric Heat Pump Conversions	$0.7	$1.1	$0.9	$0.0	**$2.7**
AMI Meters	$0.0	$3.8	$16.2	$27.7	**$47.6**
Total	$3.0	$9.5	$25.8	$28.3	**$66.6**

Rhode Island GDP impacts were estimated using the Regional Economic Models, Inc. (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 projects. REMI has over 150 US and international clients including the Rhode Island Department of Revenue; dozens of 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.

Spending on the proposed Power Sector Transformation electric projects is expected to create jobs in construction, engineering, project management, consulting, professional services, and other industries, including secondary jobs in the local service sector as workers spend their income. The result is increased economic activity, as measured by Rhode Island GDP, employment, and income.

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. Spending on specialized labor available only outside of Rhode Island was not included. Spending on local labor was allocated between general construction, electrical contractors, professional services and utility O&M before being 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.

In total, spending on the projects is projected to create 679 annual jobs in Rhode Island, from 2018 to 2021, as the projects are planned, constructed, installed and implemented. Moreover, the projects will generate an additional $46 million in Rhode Island personal income and $5.1 million in state and local tax revenues. These impacts are summarized below.

Table 2.2-2: Rhode Island Economic Impact Summary for all Projects

Rhode Island Economic Impact Summary - All Projects

	2018	2019	2020	2021	Sum
Total Jobs*	34	98	265	283	679
GDP ($m)	$3.0	$9.5	$25.8	$28.3	$66.6
Personal Income ($m)	$2.0	$6.1	$17.5	$20.0	$45.5
State and Local Tax Revenue ($m)	$0.2	$0.7	$2.0	$2.2	$5.1
0.112					

* AMI job impact does not include reduced meter reading positions.

The economic developments in the table above reflect the direct, indirect and induced economic impacts of project spending. Direct impacts are tied directly to the projects, for example contractors hired to install solar facilities, storage, electric vehicle service equipment, heat pumps and AMI meters. Indirect jobs are created in the supply chain. This includes local industries supplying tools, equipment and other materials used by project workers. Induced jobs result from the spending of the direct and indirect workers and are felt mostly in the local service sector, for example, retail. Table D-3 below shows the direct, indirect and induced employment impacts for each project. On average, direct jobs account for about 62% of all jobs created; indirect jobs account for 14%; and induced jobs account for 24%.

Table 2.2-3: Job Impacts by Project

Job Impacts - All Projects

	2018	2019	2020	2021	Sum
Direct	21	60	163	174	419
Indirect	4	13	36	38	92
Induced	8	24	66	70	169
Total	34	98	265	283	679

Job Impacts - Non AMI

	2018	2019	2020	2021	Sum
Direct	21	37	58	1	117
Indirect	4	8	12	0	24
Induced	8	15	24	1	49
Total	34	59	94	3	190

Job Impacts - Electric Heat

	2018	2019	2020	2021	Sum
Direct	5	8	6	0	18
Indirect	1	2	1	0	4
Induced	2	3	2	0	7
Total	8	12	9	0	30

Job Impacts - Company Owned Solar

	2018	2019	2020	2021	Sum
Direct	5	10	19	1	35
Indirect	1	2	4	0	7
Induced	2	4	8	1	15
Total	8	16	31	2	57

Job Impacts - Company Owned Storage

	2018	2019	2020	2021	Sum
Direct	3	5	0	0	9
Indirect	1	1	0	0	2
Induced	1	2	0	0	4
Total	6	8	1	0	15

Job Impacts - Electric Vehicles

	2018	2019	2020	2021	Sum
Direct	8	14	33	0	55
Indirect	2	3	7	0	11
Induced	3	6	14	0	22
Total	12	23	53	0	89

Job Impacts - AMI*

	2018	2019	2020	2021	Sum
Direct	0	23	105	173	301
Indirect	0	6	24	38	68
Induced	0	9	42	69	120
Total	0	38	171	280	489

For AMI, results include jobs supported within National Grid for installation of AMI meters, as well as contractors hired to install the meters. On the other hand, meter reading jobs lost is not included in the AMI analysis.