National Grid

Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid

2022-2025 Grid Modernization Plan

Testimony and Exhibits of the Grid Modernization Panel - Exhibits NG-GMP-1 through NG-GMP-7

July 1, 2021

Submitted to:
Massachusetts Department of Public Utilities
D.P.U. 21-81

Submitted by:

nationalgrid

Massachusetts Electric Company and
Nantucket Electric Company
d/b/a National Grid
D.P.U. 21-81
July 1, 2021
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INDEX OF EXHIBITS AND WORKPAPERS

Exhibit NG-GMP-1

Pre-Filed Direct Testimony of the Grid Modernization Panel

PRE-FILED DIRECT TESTIMONY

OF

THE GRID MODERNIZATION PANEL

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TESTIMONY OF THE GRID MODERNIZATION PANEL

I. Introduction

Q. Please introduce the members of the Grid Modernization Panel.

A. The members of the Grid Modernization Panel are Wajiha A. Mahmoud, William F. Jones, Samer I. Arafa, and Stephen W. Lasher.

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

A. My name is Wajiha ("Gia") A. Mahmoud. My business address if 40 Sylvan Road, Waltham, Massachusetts, 02451.

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

A. I am employed by National Grid USA Service Company, Inc. ("NGSC") as Vice President of Future of Electric. I am responsible for executing the strategy necessary to transform the electricity business to facilitate the achievement of critical policy, customer/stakeholder, environmental, resilience and affordability goals. I also develop the roadmap for this transformation and support the management of its implementation, and provide the thought leadership needed to stay at pace with emerging technological trends and stay ahead of the rapidly evolving regulatory and political environment and changing market influences and structure.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science in Electrical engineering in 2005 and a Master of Science in Electrical Engineering in 2009 from the University of Minnesota. I also hold a master's certificate in Global Enterprise Technology from Syracuse University and a certification in Asset Management from the Institute of Asset Management. Before my current position, I served as Director of National Grid's Grid Modernization solution team, responsible for the development of strategic roadmaps and near-term implementation plans associated with modernizing the distribution grid to safely, reliably and economically integrate Distributed Energy Resources ("DERs"). Prior to that position, I served as Director, Distributed Generation Ombudsperson NY, responsible for facilitating the interconnection of DER, and managing the community of distributed generation ("DG") developers/customers that interconnect to the Company's networks, to ensure customer satisfaction by resolving interconnection-related disputes and complaints. I also served as a Substation Engineering and Design Manager, responsible for delivering the capital work plan and providing technical support for substations to be safely constructed, operated and maintained using the most effective designs, equipment and quality processes. Prior to these managerial roles, I served as a Substation Engineer in 2010 and was promoted to Senior Engineer in 2013.

Q. Have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. Yes, I submitted pre-filed written testimony to the New York Public Service Commission on behalf of Niagara Mohawk Power Corporation d/b/a National Grid in docket 20-E-0380 (NMPC Rate case) as part of the Electric Infrastructure and Operations Panel.

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

A. My name is William F. Jones. My business address is 40 Sylvan Road, Waltham, Massachusetts, 02451.

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

A. I am employed by NGSC as Director of Transmission and Distribution Grid Modernization New England. I am responsible for execution of the Grid Modernization Plan ("GMP") for Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid (together, "National Grid" or the "Company").

Q. Please describe your educational background and business experience.

A. I graduated from Babson College with a Bachelor of Science, and I graduated from Bentley University with a Master of Business Administration. Prior to my current role, I led the Solutions Delivery team in the New Energy Solutions organization delivering a comprehensive Smart Grid pilot, electric vehicle programs, utility-owned solar and energy storage projects, demand response, non-wires alternatives, and grid modernization technologies. I have also held a variety of leadership positions with National Grid in performance and strategy, information technology, global finance, electric operations and network strategy.

Q. Have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. Yes. I testified in support of the Company's first GMP filing in D.P.U. 15-120. I also submitted pre-filed written testimony in the Company's GMP cost filings for calendar years 2018, 2019 and 2020 in D.P.U. 19-36, D.P.U. 20-31 and D.P.U. 21-32, respectively. I have also submitted affidavits in support of the Company's 2018, 2019 and 2020 GMP annual reports in dockets D.P.U. 20-45, D.P.U. 20-46 and D.P.U. 21-30, respectively.

Further, I submitted pre-filed testimony and testified at the evidentiary hearing in D.P.U. 14-109 and D.P.U. 15-21 addressing the Company's request for approval of its Smart Energy Solutions Pilot-related costs for the years 2012-2013 and 2014, and I submitted pre-filed testimony in D.P.U. 16-28, D.P.U. 17-53, D.P.U. 18-28/18-29, D.P.U. 19-35, and D.P.U. 20-30 addressing the Company's request for approval of Pilot-related costs for the years 2015, 2016, 2017, 2018 and 2019, respectively. I submitted pre-filed testimony in D.P.U. 16-149 in support of the Company's request to extend the Smart Energy Solutions Pilot.

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

A. My name is Samer Arafa. My business address is 40 Sylvan Road, Waltham, Massachusetts.

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

A. I am employed by NGSC as Principal Engineer in the Electric Strategy Activation – Future of Electric organization. I am responsible for developing National Grid's Grid Modernization Strategy in Massachusetts. I also lead the Company's research in its Solar Phase 2 and Phase 3 programs.

Q. Please describe your educational background and business experience.

A. I have a M.S. in Electrical and Computer Engineering from Northeastern University and am a registered Professional Engineer (PE) License #56352, type: Electrical Engineer in the Commonwealth. I am also a certified Project Management Professional (PMP). I am currently pursuing a Master of Business Administration degree at the University of Massachusetts. Prior to my current role, I was a lead Engineer in the New Energy Solutions organization supporting Smart Grid pilots with a focus on Smart Inverters and Smart Tie Switches. Before joining National Grid, I worked at Yaskawa-Solectria Solar where I held multiple roles which included Program Manager of Smart Inverters where I started Solectria's Smart Inverter program, and the role of Engineering Manager of Design Validation and Reliability where I validated and certified products to IEEE1547 and UL1741 standards among others.

Q. Have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. No, I have not.

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

A. My name is Stephen Lasher. My business address is 40 Sylvan Road, Waltham, Massachusetts, 02451.

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

A. I am employed by NGSC as Director of Electric Markets Integration under the Future of Electric organization. My responsibilities include executing leading practices and strategies to economically integrate DERs in a manner that maximizes power system, customer, and societal benefits. Prior to this role, I was Principal Engineer in the Grid Modernization Solutions Group under the US Electric Business Unit, where my responsibilities included supporting the Company's transition to a modern electric grid through identification and evaluation of potential next opportunities, technologies, or processes to provide measurable value to customers.

Q. Please describe your educational background and business experience.

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

I joined National Grid in 2016 as a Principal Engineer in the Advanced Grid Engineering Group under the New Energy Solutions organization, and later I joined the Grid Modernization Solutions group under the Electric Business Unit, and more recently I joined the Electric Markets Integration group under the Future of Electric Business Unit. My responsibilities have included the following: technical lead for Niagara Mohawk Power Corporation's Reforming the Energy Vision Distributed System Platform Demonstration Project in Buffalo, New York; technical lead for National Grid's Non-Wires Alternative

(NWA) project deferral calculations; co-author of National Grid's Grid Modernization Strategy Roadmap; and business lead for the Narragansett Electric Company's GMP.

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

From 2010 to 2012, I was employed by Satcon Technology Corporation, a Boston-based solar inverter company, as its Director of Business Development for Research and Development and later as its Director of Product Management for Central Inverters. From 2012 to 2014, I worked as a consultant to small businesses, providing technical and market insights, driving new product development programs, and helping capture new business and outside funding opportunities for the development and commercialization of emerging energy technologies. From 2014 to 2015, I was employed by eNow Inc., a Warwick, Rhode Island-based manufacturer of solar power solutions for the transportation sector, as its Vice President of Business Development.

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

Q. Have you previously testified before the Department of Public Utilities or another state's regulatory commission?

A. Yes. I testified in Rhode Island on behalf of Narragansett Electric Company d/b/a National Grid ("Narragansett") regarding its Volt-VAR optimization program as part of the Fiscal Year 2021 Infrastructure, Safety and Reliability Plan in Rhode Island Public Utilities Commission ("PUC") Docket No. 4995. Also, I presented updates regarding Narragansett's GMP filing to the PUC at the Power Sector Transformation Workshop on April 9, 2019 and the PUC Technical Sessions held on November 5, 2019 and September 24, 2020.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present the Company's GMP for calendar years 2022 through 2025, including its five-year strategic plan, four-year short-term investment plan ("STIP"), and business case. The Company's five-year strategic plan includes a proposal to achieve advanced metering functionality ("AMF") through a full-scale deployment of advanced metering infrastructure ("AMI"), which is described in more detail in the testimony of the Company's Advanced Metering Infrastructure ("AMI") panel.

Q. Are you presenting any exhibits to accompany your testimony in this case?

A. Yes. Included with our testimony are the following supporting exhibits:

Exhibit	**Description**
Exhibit NG-GMP-1	Testimony of the Grid Modernization Panel
Exhibit NG-GMP-2	Grid Modernization Plan
Exhibit NG-GMP-3 CONFIDENTIAL	Grid Facing Investments Benefit-Cost Analysis (BCA) Model
Exhibit NG-GMP-4	Proposed Changes to Existing Performance Metrics
Exhibit NG-GMP-5	Proposed Metrics for New Investments
Exhibit NG-GMP-6	Proposed Grid Modernization Provision tariff, M.D.P.U. No. 1469 (clean)
Exhibit NG-GMP-7	Proposed Grid Modernization Provision tariff, M.D.P.U. No. 1469 (redlined)

III. <u>Grid Modernization Plan</u>

Q. Please provide an overview of the Company's GMP.

A. The Company's GMP is presented in detail in Exhibit NG-GMP-2. The Company's GMP is designed to make measurable progress towards achievement of the Department's three objectives for grid modernization, which are: (1) optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing; (2) optimize system demand by facilitating consumer price responsiveness; and (3) interconnect and integrate distributed energy resources ("Objectives").[1] The GMP builds on the Company's 2018-2021 GMP approved in Docket D.P.U. 15-120. It includes a five-year strategic plan which describes how the Company intends to make measurable progress toward achievement of the Objectives, including a general investment plan but not a detailed budget. The five-year strategic plan is discussed in detail in Section 2 of Exhibit NG-GMP-2. The Company's filing also includes an AMI implementation plan, which is part of the Company's proposal to achieve AMF through a full-scale deployment of AMI, as required by the Department's May 21, 2021 Order in DPU 20-69-A. The AMI implementation plan is described in more detail in the AMI panel's testimony.

The GMP also includes a four-year STIP. The grid-facing STIP builds on investments from the Company's first 2018-2021 GMP, and is also designed to make measurable progress toward achievement of the Objectives. It is described in more detail in Section 3 of Exhibit NG-GMP-2.

Q. What previously-deployed and preauthorized technologies are included in the Company's grid-facing STIP?

A. The Company's grid-facing STIP consists of investments that are continuations of the investments approved in the Company's first GMP, and that are incremental to business as usual. This includes investments in: (1) Volt-VAR Optimization (VVO)/Conservation Voltage Reduction (CVR), including Advanced Capacitors and Regulators; (2) Advanced

[1] Order, D.P.U. 15-120/15-121/15-122 (May 10, 2018) ("Order") at 99-106.

Distribution Automation (ADA)/Fault Location, Isolation and Service Restoration (FLISR), including Advanced Recloser and Breakers; (3) Feeder Monitoring Sensors; (4) an Advanced Distribution Management System (ADMS); and (5) Information /Operational Technology ("IT/OT"), Communications.

Q. What progress have these technologies made to date on the Department's Objectives?

A. The progress of these technologies to date on achieving the Objectives is discussed throughout Section 3.1 of Exhibit NG-GMP-2.

Q. Is the Company proposing any changes to the existing metrics for the previously-deployed and preauthorized investments?

A. Yes. The Company and the other EDCs are jointly proposing changes to the existing metrics, which are reflected in Exhibit NG-GMP-4.

Q. Is the Company proposing any new technologies in its grid-facing STIP?

A. Yes. The Company is proposing new investments in: (1) a Distributed Energy Resource Management System ("DERMS"), which includes (i) an investigation, (ii) implementation, and (iii) advanced short-term load forecasting; and (2) investments to enable aggregation and market participation by DERs, as provided for by FERC Order No. 2222. These investments are described in Section 3.3 of Exhibit NG-GMP-2.

Q. Is the Company proposing metrics for these new technologies?

A. Yes. The Company's metrics proposal for these new technologies is discussed in Exhibit NG-GMP-5.

Q. Is the Company presenting a business case in support of its grid-facing STIP?

A. Yes. The Company presents its business case throughout Exhibit NG-GMP-2. Specifically: (1) the goals and drivers for investments are described in Sections 2.1, 3.2 and 3.3; (2) the technology/project descriptions are described in Sections 3.2 and 3.3; (3) the costs and benefits, including both quantified and qualitative benefits, are discussed in Section 4, as well as Sections 3.2 and 3.3; (4) the achievement of performance metrics and state policy goals are discussed in Sections 1.3, 2.1, 2.2, 3.1, 3.2.6 and 3.3.3; and (5) an overall assessment of the STIP is discussed throughout Section 3.

Q. Does the Company's proposal result in reasonable bill impacts?

A. Yes, it does. The Company's proposed grid-facing investments, with a budget of $316.26 million (nominal) over four years, would result in a total cumulative residential customer bill impact of approximately 1.63% over that timeframe.

Q. How do the proposed investments benefit low-income customers and environmental justice communities ("EJCs")?

A. The benefits of the proposed investments to low-income customers and EJCs are described in Sections 3.2 and 3.3 of Exhibit NG-GMP-2. Please also see the testimony of the Company's AMI panel for further discussion of these benefits.

Q. Is the Company proposing any demonstration programs in its GMP?

A. Yes, the Company is proposing two demonstration projects to study new DG interconnection schemes and the options for interconnecting increasing amounts of DG to the Company's system. First, the Company is proposing an Active Resource Integration demonstration project, to actively manage DG to enable increased DG interconnections in appropriate areas on the Company's distribution system. Second, the Company is proposing a Local Export Power Control demonstration project, to explore the zero-export capabilities of a Power Control System in a DG facility in order to lower interconnection costs and reduce interconnection timelines by reducing or eliminating the need for distribution impact studies. The two demonstration projects are described in detail in Section 3.4 of Exhibit NG-GMP-2. The information presented in Exhibit NG-GMP-2 demonstrates that these proposed demonstration programs: (1) are consistent with applicable laws, policies, and precedent; (2) are reasonable in size, scope, and scale in relation to the likely benefits to be achieved; (3) propose adequate performance metrics and evaluation plans; and (4) will result in minimal bill impacts to customers.

Q. How does the Company propose to recover the costs of its grid modernization investments?

A. The Company has an existing Grid Modernization Provision tariff, M.D.P.U. No. 1445, which provides for recovery of its GMP costs through Grid Modernization Factors. The Company proposes to continue this tariff, with minor changes for plan terms and dates, including continuation of the Grid Modernization Factors. The Company is including with this filing clean and redlined versions of its proposed revised tariff, M.D.P.U. No. 1469, as Exhibit NG-GMP-6 (clean) and Exhibit NG-GMP-7 (redlined).

IV. Timing of Department Review

Q. What is the Company's expectation regarding the scope and timing of the Department's review of its proposed 2022-2025 GMP?

A. National Grid recognizes that electric grid modernization is a complex undertaking involving a broad range of stakeholders. National Grid also recognizes that the Department will need time to thoroughly investigate the Company's filing (in conjunction with other grid modernization filings) and to render a final decision on the elements of the Company's 2022-2025 GMP.

However, the Company is proposing a number of investments that have been previously deployed and preauthorized, to continue into 2022 and beyond. The Department required the Company to identify proposed investments in grid-facing technologies that have been previously deployed and/or preauthorized, including separate itemized budgets, testimony, and supporting documentation. D.P.U. 20-69-A, at 37. Because the Department has reviewed these investment categories before, the Department expects that its investigation of any previously deployed and/or preauthorized technologies can be streamlined. Id.

Therefore, the Company is requesting streamlined review of its previously deployed investments proposed for implementation in 2022. Ideally, the Company would need a decision by December 2021 to avoid disruptions in the overall GMP implementation.

Q. What proposed investments to be implemented in 2022 were previously deployed in the Company's 2018-2021 GMP?

A. The Company is proposing to invest in multiple different programs that were deployed and preauthorized in the Company's 2018-2021 GMP. As noted previously, this includes investments in: (1) VVO/CVR; (2) ADA/FLISR; (3) Monitoring & Control; (4) ADMS; and (5) Information/Operational Technology (IT/OT), Communications. These investments are further outlined in Section 3.2 of Exhibit NG-GMP-2.

Q. Why is it important for the Department to streamline its review of the investments proposed in 2022 that were previously deployed in the Company's 2018-2021 GMP?

A. The Commonwealth of Massachusetts has worked very hard over the past ten years to enable a successful transition to a modernized electric grid characterized by a system that is designed to handle severe weather and robust interconnection of DG, among other goals. The Company's work through its approved GMP to accommodate the amount of DG connected to or looking to connect to the Company's system is a fundamental prerequisite to the success of this vision. The Department's regulatory process to oversee and authorize grid modernization work must align with the gravity, breadth, and complexity of the work underway by providing a stable and consistent funding process. Loss of funding or funding uncertainty for calendar year 2022 has the potential to disrupt the Company's ongoing grid modernization programs and would be highly detrimental to the interests of customers and others relying on the Company's grid modernization initiatives.

For example, many of the materials and equipment have been extremely difficult to source, and in some cases have significantly long lead times once orders are placed. The inability to procure the material and equipment would result in considerable costs and delays. The resulting delays in customer benefits would be substantial. If the VVO program is disrupted, for instance, the Company will not have the materials and equipment available to continue to expand the number of feeders under VVO control, delaying benefit to customers.

V. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit NG-GMP-2

Grid Modernization Plan

Grid Modernization Plan

For

Massachusetts Electric Company
and
Nantucket Electric Company
d/b/a
National Grid

Table of Contents

1. Introduction

1.1. Executive Summary

Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid (the "Company" or "National Grid") proposes herein its second Grid Modernization Plan ("GMP"). The GMP includes: (1) its five-year strategic plan for the years 2022-2026, which includes its Advanced Metering Infrastructure ("AMI") Implementation Plan, and (2) its four-year investment plan for the years 2022-2025 for grid-facing investments.[1] The GMP is designed to achieve the Massachusetts Department of Public Utilities' (the "Department") grid modernization objectives to: (1) optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing; (2) optimize system demand by facilitating consumer price responsiveness; and (3) interconnect and integrate distributed energy resources.[2]

The Company's first GMP (for the years 2018-2021) was focused on implementing foundational grid modernization technologies and capabilities, including: an Advanced Distribution Management System ("ADMS"), enabling real-time visibility and control of the Company's distribution system; Feeder Monitors, enabling feeder level real-time visibility and the provision of data to improve planning models, analysis, and power quality, and reducing outages; an Advanced Distribution Automation ("ADA") system, improving system reliability, such as reductions in customer outage time and increased customer satisfaction; Conservation Voltage Reduction ("CVR") and Volt VAR Optimization ("VVO"), resulting in reduced energy demand and lower costs to customers; and critical investments in Communications and Information/ Operational Technology ("IT/OT"), improving real-time communication and data management. These investments have allowed the Company to achieve measurable progress towards the establishment and operation of a modern electric grid.

With a continuing vision of enabling a clean energy transition for our customers while maintaining a resilient and cost-effective electric system, the Company's second GMP (for the years 2022-2025) contains the Company's proposals to continue deployment of these foundational investments and unlock their advanced capabilities to make further progress on the Department's objectives, while also striving to enable the Commonwealth's net zero emissions target by 2050. The Company proposes the continuation of foundational investments, including: ADMS; Feeder Monitors; ADA; CVR and VVO across the Company's distribution system; and essential enabling investments in Communications and IT/OT. The Company also proposes several new grid modernization investments, which will enable new and necessary capabilities, including: advanced short-term load forecasting at the distribution asset level; a Distributed Energy Resource Management System ("DERMS") investigation into a software platform that enhances the Company's ability to track, plan, manage and operate distributed energy resources

[1] The Company's customer-facing investments consist of its Advanced Metering Infrastructure proposal, which is contained entirely in the five-year strategic plan.

[2] D.P.U. 15-120/15-121/15-122 (May 10, 2018) at 99-106.

("DERs"); and discrete investments to prepare for the implementation of Federal Energy Regulatory Commission ("FERC") Order No. 2222.[3] The Company proposes a set of statewide and company-specific performance metrics to accompany these new investments.

The Company also proposes two demonstration projects: (1) Active Resource Integration, to field test a new flexible interconnection option that could enable the Company to accelerate DG interconnections and increase the energy production of DGs per unit of system capacity; and (2) Local Export Power Control, to explore the net zero thermal impact capabilities of a Power Control System in a DG facility to lower interconnection costs and reduce interconnection timelines by reducing or eliminating the need for distribution impact studies.

Finally, the Company has included its AMI Implementation Plan, including: a timeline for AMI deployment; a deployment strategy that aligns with the forecast increased risk of the existing fleet of AMR meters that are at or near the end of their useful life; a Customer Engagement Plan; a benefit-cost analysis ("BCA"); and a proposed cost recovery mechanism for AMI-related investments. Consistent with the Department's May 21, 2021 D.P.U. 20-69-A Order ("D.P.U. 20-69-A") directing the Company to file a plan for full-scale implementation of AMI, the Company proposes to begin AMI implementation in 2023 with a four and-one-half year program that will transform the way customers interact with their energy usage.

1.2. Procedural Background

On May 10, 2018, the Department issued D.P.U. 15-120/15-121/15-122 (the "Order") approving in part the GMPs for the Company, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), and NSTAR Electric Company d/b/a Eversource Energy ("Eversource") (together the "Electric Distribution Companies" or "EDCs"). In the Order, the Department pre-authorized grid-facing investments over three-years (2018-2020) for the EDCs and adopted a three-year regulatory review construct for preauthorized grid modernization investments. Order at 106-115, 137-174. The Order provided that the EDCs will submit GMPs every three years, which will be addressed in separate proceedings, and the Department will require the EDCs to submit a five-year strategic plan describing how they propose to make measurable progress towards the Department's grid modernization objectives.

In the Order, the Department refined its objectives for grid modernization, based on developments in the electric industry and its review of the EDCs' GMPs, into the three objectives described previously. In D.P.U. 15-120-D/15-121-D/15-122-D, the Department extended the term of the EDCs' first three-year grid modernization plans through the end of 2021 and directed the EDCs to file their next three-year grid modernization investments plans (and five-year strategic plans) on July 1, 2021.

In D.P.U. 20-69-A, at 28, the Department directed the EDCs to include in their July 1, 2021 GMP filings: (1) a five-year strategic plan (including a plan to achieve advanced metering functionality through the

[3] FERC Order No. 2222, September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

full-scale deployment of AMI); and (2) separate four-year grid-facing and customer-facing short-term investment plans. The Department also directed the EDCs to separately file their EV proposals by July 14, 2021, and to file any battery energy storage proposals in separate dockets as well. *Id.* at 49, 50.

1.3. Grid Modernization Vision

Several key factors have affected the energy industry and consequently shaped and influenced National Grid's vision of grid modernization. The energy transition and rapid development of new technologies has led to new and evolving customer needs and expectations. More progressive policies and regulatory requirements have evolved to support clean energy deployment and the need to decarbonize. The rise in both DG and load combined with the growing frequency of extreme weather events have increased the variability of system load profiles, requiring utilities to enhance their capabilities to manage and predict such events to safeguard the resiliency and reliability of the electric distribution system.

The Company's vision of grid modernization is a fundamental component of its overall Future of Electric vision, which includes a smarter grid that has sufficient monitoring and control to reliably manage an increasingly complex and dynamic distribution system. In addition to controlling utility equipment, the modern grid operator will need integrated processes and tools to leverage DERs as an efficient resource for customers and the resiliency of the grid.

Grid modernization is required to accommodate the rapidly changing technological trends and customer expectations impacting the electric distribution system. Significant change is occurring across the energy industry due to evolving customer needs and expectations, driven by the increased adoption of DERs, including solar, energy storage, and EVs, and "smart" customer devices (e.g., networked EV chargers, HVAC controls, smart inverters) that can actively manage energy use in customers' homes and businesses. The current ways of interconnecting DERs into the existing electric distribution system infrastructure are becoming increasingly difficult and expensive.

The Commonwealth committed to net zero emissions by 2050 and aggressive interim greenhouse gas ("GHG") emission limits in the comprehensive climate legislation signed in March 2021, which will accelerate the energy transition.[4] In December 2020, the Commonwealth also released its 2050 Decarbonization Roadmap ("2050 Roadmap"),[5] which offers a glimpse into the long-term future of the electric grid. The charts in Figure 1, Future Energy Demand and Supply, project that by 2050 wind and solar will account for more than 80% of energy generation in Massachusetts, and that there will be rapid growth in the relative load share from emerging technologies such as EVs, conversion loads, and space and water heaters.

[4] An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, Chapter 8 of the Acts of 2021.
[5] Massachusetts 2050 Decarbonization Roadmap, https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download

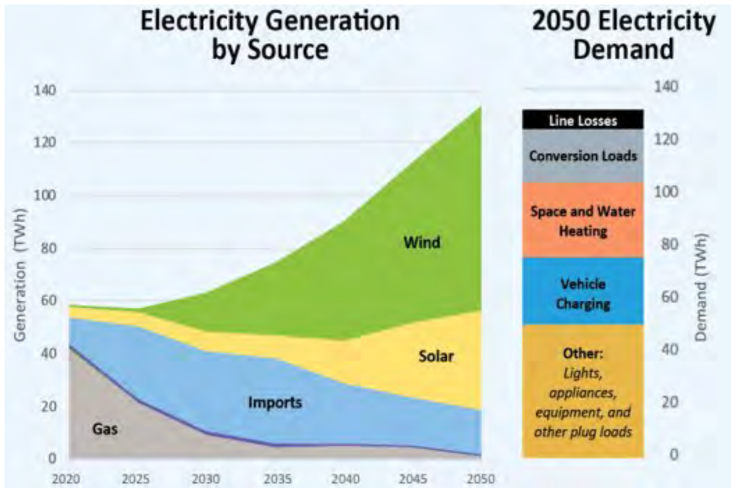

Figure 1: Future Energy Demand and Supply[6]

In December 2020, the Commonwealth also released its interim 2030 Clean Energy and Climate Plan ("2030 CECP"), which supports "a more dynamic, bidirectional distribution system [which] will allow for greater electrification and minimize the cost of integrating DERs."[7]

Furthermore, FERC Order No. 2222 ("FERC O2222"), issued in September 2020, requires that wholesale markets allow all DERs to participate in markets under a unified set of rules so the resources can be aggregated and optimized. Changes to wholesale market access rules will allow far greater participation of DERs at the Independent System Operator-New England ("ISO-NE"). Although the timing for market design and implementation of forthcoming market participation models is currently being determined, the Company is involved in conversations at the ISO-NE and is planning for future market participation of DERs.

These recent federal and state policies and regulations closely align with the Department's grid modernization objectives. These policies and objectives dovetail with the Company's vision of a modern electric grid, as they characterize a system designed around optimal integration of various DERs, both generation and load, to deliver the Commonwealth's clean energy and climate goals while also maintaining an affordable and reliable electric system for customers.

Whereas electric distribution equipment historically has required only local autonomous control settings, without the need for remote monitoring or real-time controls, the two-way flow of information and energy, enabled by feeder monitoring and advanced metering functionality, allows the Company to

[6] From the Massachusetts 2050 Decarbonization Roadmap, at 24.
[7] Massachusetts 2030 Clean Energy Climate Plan, at 43, https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download.

manage the distribution system with more granularity, including more real-time visibility, automation and control of the distribution system and customer end-use devices, and increased ability to receive and communicate energy usage, pricing, and other information to customers.

Today's system load profiles are expected to change drastically and unpredictably with higher penetration of intermittent DG (such as solar) and emerging load technologies (such as EV chargers), and with the increasing frequency of natural disasters and extreme weather events. More granular short-term (e.g., week-ahead to intra-day) load and generation forecasting at the distribution asset level will be required to support identification of distribution system constraints in advance, increasing the Company's ability to optimally develop, plan and execute system reconfiguration, switching orders and activation of DER programs to secure the distribution system. The Company envisions these granular forecasts will be incorporated into its ADMS load flow and distribution state estimation applications to enhance its simulation capability and insight on future system state predictions. The Company is also considering how these forecasts can enable and expand its DER programs, including existing demand response programs, to address localized system constraints.

Executing on this future vision involves National Grid's evolution from a simple one-way to a bi-directional power flow company that manages an increasingly dynamic and complex distribution system. The Company envisions refining its control systems to manage the high penetration of unmanaged DERs. Initially, some of this control will be enabled through an ADMS, but ultimately, as customer DER penetration grows, an additional DERMS will be needed for more granular control, which will enable the Company to streamline DER interconnections and reduce costs for customers.

As the electric distribution system evolves, the Company will need to implement more control systems like ADMS and DERMS, and to deploy more digital assets that provide real-time system visibility (e.g., voltage, power flow, asset condition) and improve response time. With these grid modernization investments, the Company will utilize granular system data to make "real-time" system dispatch decisions, ensuring that the distribution system is efficient, safe and reliable with significantly higher levels of DERs. Additionally, with the full-scale deployment of AMI, the Company will transform the way it delivers energy, empowering customers and taking further meaningful steps to achieve shared clean energy goals.

2. Five-Year Strategic Plan

2.1. General Investment Plan

National Grid proposes eleven categories of grid modernization investments over the next five years (2022-2026), outlined in Figure 2, General Investment Plan.[8] Detailed four-year budgets and five-year schedules can be found in the Company's Four-Year Grid-Facing Investment Plan in Section 3.

Grid Modernization Investments			Department Objectives			Enable FERC O2222
Category	**Subcategory**	**Status**	**Optimize System Performance**	**Optimize System Demand**	**Integrate DER**	
Monitoring & Control	Feeder Monitors	Pre-authorized	✓		✓	✓
VVO	VVO/ CVR	Pre-authorized	✓	✓	✓	
ADA	ADA/ FLISR	Pre-authorized	✓			
ADMS	ADMS Core Functionality Mobile Dispatch RTU Separation Distribution PI Historian GIS Data Enhancements	Pre-authorized	✓	✓	✓	✓
Information Technology	Enterprise Integration Platform Data Management Cyber Services	Pre-authorized	✓	✓	✓	✓
Communications	Communication & Networking INOC	Pre-authorized	✓	✓	✓	✓
Measurement, Verification & Support	M&V Project Management	Pre-authorized	✓	✓	✓	✓
DERMS	DERMS Investigation DERMS Implementation Advanced S-T Load Forecasting	New	✓	✓	✓	✓
Demonstration Projects	Active Resource Integration Local Export Power Control	New	✓	✓	✓	✓
FERC O2222	Settlement System DERA Operations Portal	New	✓	✓	✓	✓
AMI	AMI Meters Communications Supporting Systems	New	✓	✓	✓	✓

Figure 2: General Investment Plan

[8] Per the Department, the Companies' five-year strategic plan shall include a general investment plan but not a detailed budget. D.P.U. 20-69-A at 29.

2.2. Progress on Grid Modernization Objectives

National Grid's second GMP is designed to make measurable progress towards achievement of the Department's three grid modernization objectives through its proposed grid-facing and customer-facing investments. As indicated in Figure 2, General Investment Plan, each of the eleven categories of proposed investments (new and preauthorized technologies) make progress on at least one or more of the three grid modernization objectives.

The Company's second GMP contains a comprehensive suite of investments and initiatives that will continue to modernize the Company's distribution system and deliver significant customer benefits, including energy supply savings, reduced outage duration, reduced numbers of customers impacted by outages, and improved system operations and system planning. The continuation of preauthorized investments, as well as new investments, will provide enhanced and new functionality necessary to enable increased DER integration capacity.

With respect to optimizing system performance, the Company's continued investment in Feeder Monitors and VVO to expand deployment on primary distribution feeders will support compliance with voltage and thermal protection requirements as customer DER adoption grows. The voltage control, load control, and near real-time power measurements provided by these technologies will enable engineering and operations personnel to better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all customers through optimization. The Company's continued investment to deploy ADA on its highest-value feeders will further reduce customer outage restoration time.

The Company's continued investment in Communications and IT/OT will further facilitate the connection, communication and operation of grid devices. Managing high levels of DER integration, while ensuring electric network stability and performance, will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices (i.e., feeder monitors, and advanced capacitors, regulators, reclosers, and breakers) to support VVO/CVR and Fault Location, Isolation, and Service Restoration ("FLISR"), AMI, and other capabilities, there will be an enormous growth of incoming data. IT/OT investments in Data Management and the Enterprise Integration Platform will be necessary to enable grid modernization functionalities and realize their full benefits.

Investment in full-scale deployment of AMI will enable the provision of end-to-end data, two-way power and information flow, and remote capabilities to support the grid-facing grid modernization applications, such as outage management, and increased operational efficiency.

With respect to optimizing system demand, the Company's continued investment to expand deployment of VVO/CVR on primary feeders will benefit customers by reducing demand and energy use.

The VVO control schemes coordinate multiple voltage regulating devices on a feeder to achieve optimal CVR performance. In addition, the Company's AMI Implementation Plan lays out a roadmap to achieve full-scale deployment of AMI in its service territory. Investment in AMI will enhance customers' understanding, choice, and control over their energy consumption. Toward this end, full-scale deployment of AMI will enable energy reductions and other benefits through increased customer control and management of energy usage via energy insights, personalized energy efficiency offerings, demand response programs, high-bill alerts, access to near real-time energy usage data, and future opportunities for dynamic time-varying rate ("TVR") structures (e.g.*,* on-peak periods and critical peak pricing).

With respect to interconnecting and integrating DERs, the Company's continued investment in Monitoring and Control (i.e., AMI, ADMS, Feeder Monitors) will permit planners to use more granular coincident data in the development of system planning models. These more precise models will improve the analysis that drives Area Planning Studies and interconnection distribution impact studies in response to customer load and interconnection applications and will facilitate the Company's DG/DER long-term planning proposal if approved in docket D.P.U. 20-75.[9]

The Company is proposing new investments to facilitate DER integration, which include:

- DERMS Investigation – Test software tools to integrate customer-controlled DER with grid operations, including dispatching DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution, in preparation for DERMS implementation.
- DERMS Implementation – Implement the DERMS and associated DERMS platform integration system, following the DERMS investigation.
- Advanced Short-Term Load Forecasting – Improve granular short-term forecasting capabilities to address substation and feeder constraints, and enable the Company to optimally develop, plan and execute system reconfiguration, switching orders and activation of DER programs to secure the distribution system. For example, improving the Company's ability to forecast feeder and substation-level peaks will enable the Company to dispatch demand response to reduce local peak demand or shift demand away from peak hours by incentivizing off-peak EV charging behavior.

The Company is proposing two new demonstration projects to improve DER interconnection, which include:

- Active Resource Integration ("ARI") – Field test a new flexible interconnection option that could enable the Company to accelerate DG interconnections and increase the energy production of DGs per unit of system capacity. Actively managing DG is one of many use cases for DERMS and

[9] Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation.

therefore ARI will help inform the Company's future implementation plan of an enterprise-wide DERMS.

- Local Export Power Control – Explore the net zero thermal impact capabilities of customer-owned Power Control Systems as a tool to lower interconnection costs and expedite interconnection timelines by reducing the need for distribution impact studies for such DER facilities.

AMI is also a key part of the Company's broader effort to interconnect and integrate DERs. Specifically, AMI provides distributed sensing capabilities, supporting a more flexible grid that can accommodate the increased levels of distributed generation required to meet the Department's objective. This more intelligent and flexible grid will also: provide transparency regarding system needs and opportunities when siting DER technologies; support DER optimization through more granular data and control at the customer level; and provide near real-time data that will allow for improved load and DER forecasts as part of the planning process.

With respect to all three grid modernization objectives, the Company continues to invest in the ADMS/Distribution Supervisory Control and Data Acquisition ("DSCADA") platform. By incorporating control and automation capable grid devices (e.g., Advanced Capacitors and Regulators, VVO, and FLISR) with the centralized ADMS platform, these technologies support operations in abnormal grid configurations. The ADMS helps optimize both system performance and system demand by creating a more efficient electric system with greater real-time monitoring and control, bi-directional load flow and future state simulation capabilities, better-managed system voltage, and fewer line losses. It centralizes data, visualization, monitoring, control, and automation capabilities, maximizing operational process efficiencies. The deployment of a new DSCADA system will enable management of the proliferation of data from remote telemetered devices on the distribution system to ensure continued reliability. Operational planning and real-time monitoring and control of DER is planned to be accomplished through a combination of the distribution network analytic applications in the ADMS platform, foresight from advanced short-term load forecasting, and the DERMS solution the Company intends to implement, following its DERMS investigation.

2.3. Timing and Prioritization of Investments and Other Activities

The Grid Modernization Roadmap ("Roadmap") outlines the Company's proposed timing for its grid modernization investments over the next ten years and includes other related programs/ initiatives that support the full universe of grid modernization investments (not only investments that are incremental, or eligible for short-term targeted cost recovery).

The Company's approach to modernize its electric distribution system goes beyond the scope of this GMP and includes proposals for energy storage and EV charging infrastructure deployment. It also builds off of and complements the Company's current efforts in supporting programs/ initiatives, including its participation in the Massachusetts Technical Standard Review Group to implement the updated IEEE-1547 standards, its research and development work on smart inverters in its Solar Phase II and III Programs, and its proposal for integrated transmission and distribution planning studies and long-term forecasting work in D.P.U. 20-75. See Figure 3, Grid Modernization Roadmap.

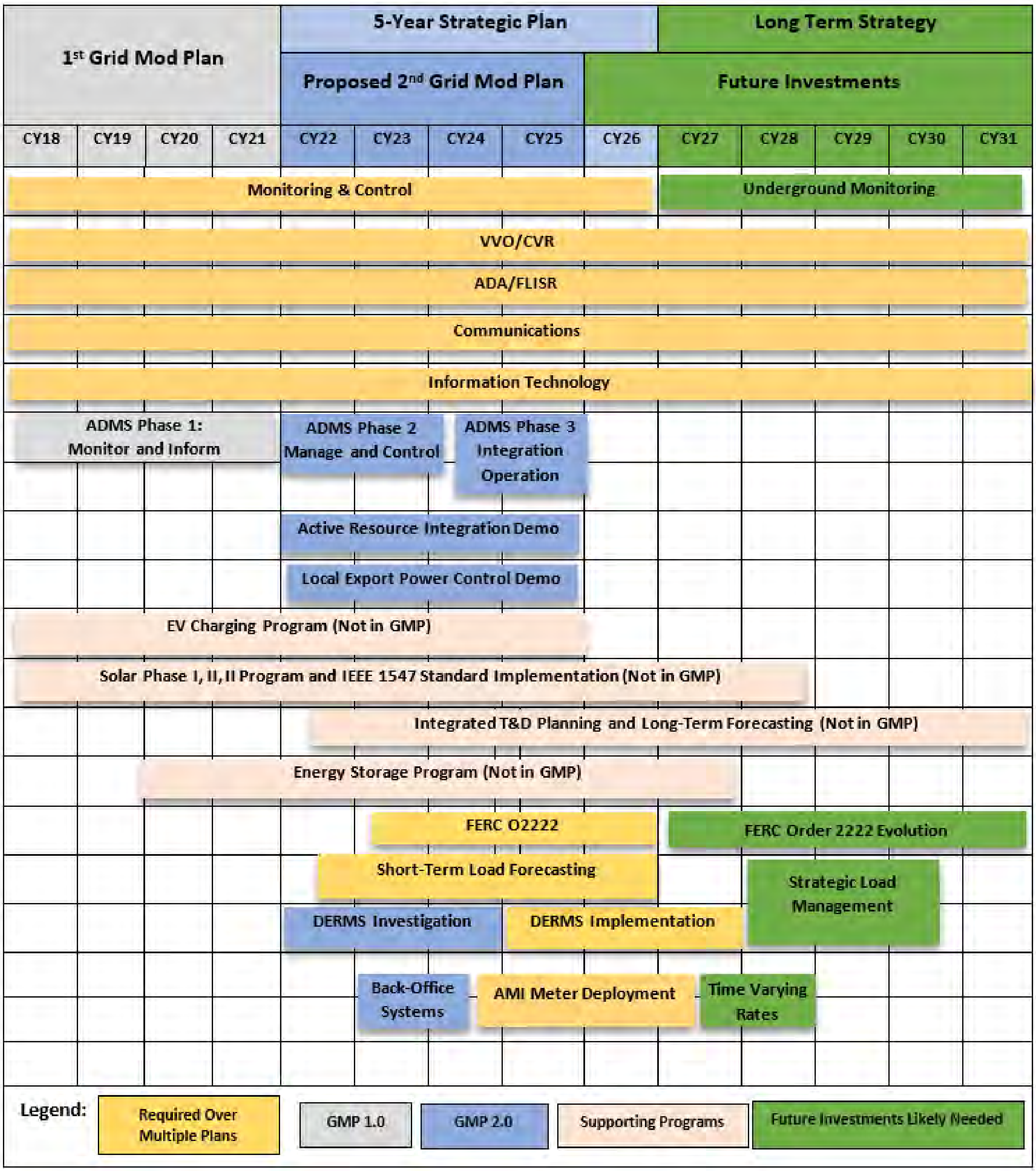

Figure 3: Grid Modernization Roadmap

Grid modernization is not a single, one-time project. The term "grid modernization" encompasses an array of investments needed over time as the electric distribution grid evolves. The Roadmap includes projects at different levels of maturity. Projects in the initial years of the Roadmap have detailed implementation plans, whereas projects in the later years of the Roadmap, or those that will be scaled in response to future system needs, are in some cases less detailed at this time.

The initial investments in the Company's first GMP were focused on laying the foundational components of a modern grid. The proposed investments in the Company's second GMP are focused on integrating these components into a holistic system and unlocking and optimizing their capabilities. Investments in the foundational components are proposed to continue in the second GMP and in the following years as the Company enables these capabilities on key feeders and substations across the Company's service territory. Proposed investments in the second GMP also focus on integrating the Company's system with its customers' DERs and end-use devices to allow the Company to efficiently leverage grid modernization functionalities and new technologies, programs, and services to meet evolving customer expectations and grid needs. To better communicate and interact with customer DERs and to facilitate DER interconnection, new tools and capabilities are required. As such, this second GMP proposes new investments to support implementation of FERC O2222, advanced short-term load forecasting, a DERMS investigation, DERMS Implementation, and two demonstration projects. The second GMP also includes investments in back-office systems and AMI metering to enable full-scale deployment of AMI.

The Roadmap beyond CY 2026 is intended to guide the development of future investment plans. The form and function of the distribution system is evolving and is expected to change significantly over the next several years. The Company anticipates the need to adapt and adjust its plans in later years considering several factors, including the actual pace of DER penetration over time and the corresponding system impacts as determined through the Company's on-going distribution planning processes, the availability of new grid modernization technologies, and the evolution of policies and regulatory proceedings.

2.4. AMI Implementation Plan

The Company's proposal to achieve advanced metering functionality through a full-scale deployment of AMI is described in detail in the Company's AMI Implementation Plan. The plan includes a timeline, a deployment strategy that aligns with the increased risk of failure for the Company's existing fleet of AMR meters that are at or near the end of their useful life, a Customer Engagement Plan, a BCA, and a proposed cost recovery mechanism for AMI-related investments. Please see Exhibit NG-AMI-1 through NG-AMI- for the pre-filed testimony and exhibits of the Company's AMI Panel.

3. Four-Year Grid-Facing Investment Plan

An overview of the Company's four-year grid-facing investment plan is in Figure 4, below.

Grid Modernization Investments		**Four-Year Investment Budgets (in $M)[10]**					
Category	**Subcategory**	**2022 Continuing**	**2022 New**	**2023**	**2024**	**2025**	**Total**
Monitoring & Control	Feeder Monitors	0.98		1.02	1.05	1.09	**4.14**
VVO	VVO/ CVR	12.15		17.32	22.89	24.08	**76.44**
ADA	ADA/ FLISR	7.92		10.18	11.53	12.95	**42.58**
ADMS	ADMS Core Functionality	13.70		9.89	5.85	4.94	**34.39**
ADMS	Mobile Dispatch	3.55		3.65	2.86	0.89	**10.95**
ADMS	RTU Separation	1.30		1.33	1.37	1.41	**5.41**
ADMS	Distribution PI Historian	0.94		0.19	0.12	0.12	**1.37**
ADMS	GIS Data Enhancements	3.09		3.48	1.19	0.54	**8.30**
IT	Data Management	2.19		1.64	1.53	0.50	**5.85**
IT	Enterprise Integration Platform	2.63		2.19	2.40	0.92	**8.14**
IT	Cyber Services	0.71		0.54	0.56	0.55	**2.35**
Communications	Communications & Networking	8.30		24.24	16.56	24.77	**73.88**
Communications	INOC	3.86		4.43	1.74	1.06	**11.09**
Measurement, Verification & Support	M&V	0.40		0.41	0.42	0.43	**1.66**
Measurement, Verification & Support	Project Management	0.65		0.67	0.69	0.70	**2.71**
DERMS	DERMS Investigation		0.49	0.53	0.83	0.05	**1.90**
DERMS	DERMS Implementation		0.00	0.00	0.00	TBD[11]	**TBD**
DERMS	Advanced S-T Load Forecasting		2.60	1.79	0.78	0.81	**5.98**
Demo Project	Active Resource Integration		2.26	2.11	0.90	0.93	**6.20**
Demo Project	Local Export Power Control		0.00	0.15	0.01	0.02	**0.17**
FERC O2222	Settlement System DER Operations Portal		2.76	3.06	3.76	3.14[12]	**12.73**
TOTAL		**62.37**	**8.11**	**88.84**	**77.05**	**79.89**	**316.26[13]**

Figure 4: Four Year Grid-Facing Short-Term Investment Plan (2022-2025)

3.1. Preliminary Assessment of Progress on Grid Modernization Objectives

This section discusses the Company's previously deployed technologies and provides a preliminary assessment of how they have contributed to the Department's grid modernization objectives.

Objective #1 - Optimizing system performance by attaining optimal levels of grid visibility, command and control, and self-healing.

ADA/FLISR:

- ADA/FLISR helps optimize system performance by reducing customer outage times. The program reduces the minutes of interruption experienced by customers by automatically re-routing power in a way that the electric system previously was not capable of.
- The Company anticipates that by the end of CY 2021 it will have completed 22 ADA schemes on a total of 44 feeders, which represents 4% of its total feeders in the Company's service territory, serving over 100,000 customers.

Table 1: ADA/FLISR Deployment

Milestone	CY19	CY20	CY21
FLISR Annual Feeder Installs	0	16	28
Schemes	0	8	14
Cumulative Feeders with FLISR	0	16	44
Percentage of Feeders with FLISR	0%	1%	4%

- The Company had commissioned a FLISR scheme in the Merrimack Valley on December 31, 2020 as part of the ADA program. The East Boxford circuit has been one of National Grid's poorest-performing circuits in recent years in terms of customer interruptions. The FLISR scheme operated in the midst of the nor'easter to avoid a long duration power outage to approximately 400 customers in East Boxford. Effectively, the FLISR scheme restored service to 396 customers in 20 seconds. The remaining 593 customers were restored in 117 minutes after crews had repaired the fault. Without the FLISR scheme, all 989 customers would have experienced the full 117-minute outage.

[10]The inflation rate is based on the average projected Gross Domestic Product: Chain-Type Price Index ("GDPCTPI") for the four quarter average increases from fiscal years 2022 to 2023, 2023 to 2024, and 2024 to 2025 and is equal to 2.671.

[11] [12]As provided in D.P.U. 20-69-A at 38 n.17, the Company will update its proposed budgets for DERMS Implementation and FERC O2222 for CY2025 as soon as possible.

[13] Total may not equal sum of all the rows due to rounding.

- This event demonstrated the self-healing capabilities provided by the ADA/FLISR investments. Specifically, for this single event, the technology restored approximately 40% of the impacted customers in less than a minute and reduced the overall CMI for the event by approximately 40%.

Feeder Monitors:

- Feeder Monitors improve grid visibility which assists with optimizing system performance and determining outage locations and damages, helping the Company route its crews to the affected areas on the system with greater speed and accuracy to restore power to customers more quickly. Utilizing PI Historian data collected through Feeder Monitors, system planning engineers can verify if feeder heads are impacted by a storm. Additionally, Feeder Monitors support the ADMS and DERMS in the command and control of the system.
- The Company anticipates that by the end of calendar year 2021 that it will have installed Feeder Monitors at the heads of 202 feeders.

Table 2: Feeder Monitor Deployment

Milestone	CY19	CY20	CY21
Feeder Monitors	5	66	131
Feeders Monitors Cumulative	5	71	202
Percentage with (FM) Visibility	0%	6%	17%

- During the winter storm event on October 17th, 2019, the feeder monitors saved time responding to a predicted assessment of the 910W2 feeder in Hanover, Massachusetts. During the emergency outage our planning engineers assessed the customer calls reporting outages centered around the Water Street 910 Substation. Before dispatching damage assessors, planning engineers utilized the device data to verify the most likely impacted phase and location to more efficiently route resources.
- In December 2020, a commercial customer, the East Bradford Ski Resort, reported low voltage issues. Ski season had just started on December 19, 2020, and the Ski Resort was an important part of the local economy especially in the pandemic year. The Company used the Feeder Monitor to evaluate the voltage issue and determine corrective action. Before the Feeder Monitor, the Company only had telemetry from within the substation or had to install temporary telemetry at various locations. It relied on customer feedback to deduce circuit voltage conditions, needing multiple customer touchpoints and suboptimal customer experience. Correcting a low voltage issue would have required more time and resources, potentially involving repeat trips to the substation and a longer-duration impact to ski activity.

- The Company's standard practice for several years has been to deploy remote interval monitoring and control for new substations and feeders as part of the Company's Energy Management System ("EMS") Program. The combination of this strategy and the Feeder Monitor strategy above has given the Company visibility in more than 95% of its feeder head with the remaining locations being of less significance (e.g. low number of customer counts).

<u>ADMS:</u>

- The Company will continue to invest in the development and progression of an ADMS. The ADMS will expand situational awareness and visibility of the electric distribution grid on a centralized system. It creates a platform to support the integration of distributed resources, enables utilization of the exponential growth of remote monitoring, centralizes control and distribution automation, and digitalizes operational processes. An ADMS also enables system operations to maintain or improve outage response under the growing system complexities associated with the integration of DERs and leverages bi-directional operational power flow coupled with simulation functionality to optimize grid configuration decisions maximizing asset and resource utilization.
- The Company completed Phase 1 of its ADMS program in May of 2021 which put baseline distribution management system applications such as load flow, restoration switching analysis, simulation mode, and experimental fault location capabilities in service on 125 distribution circuits for the electric distribution control rooms to use in a monitor and inform capacity.
- The ADMS Phase 1 roll out included the following:
    - ✓ Build out governance frameworks, team structure, and KPIs for project
    - ✓ Requirements and capability specification and enterprise architecture review
    - ✓ Future state process design considering Phase 1 functions
    - ✓ Change management and training functions
    - ✓ Data element identification and GIS data improvements, extract improvements
    - ✓ ADMS network and infrastructure specification, procure and build
    - ✓ Acceptance testing of baseline monitor and inform applications
    - ✓ Production implementation of baseline application functionality on 125 distribution circuits.
- Phase 2 – 3 of the ADMS program will continue progressing rollout of baseline applications introduced in phase 1 ADMS. These follow-on phases will also centralize outage management capabilities within ADMS allowing data sharing across applications improving outage visibility and response by pairing real time data with the outage management system. Phase 2 – 3 will build out control and management functionality via DSCADA allowing the centralization of distribution automation (VVO and FLISR) and DER control as well as continuing to expand applications and integrations with other grid modernization and digital investments.

<u>Communications, IT/OT:</u>

- Investment in enabling infrastructure continues to progress to support enablement of the ADA, Feeder Monitor, VVO/CVR and ADMS investments which will support optimizing system performance. While the broader communications plan and investments continue, interim investments to enable grid visibility and command and control have been delivered. The enterprise integration platform has been established to support the ADMS Phase 1 and the data management platform is being enabled to support the additional data and analytics needs. The following milestones have been completed to date.

Table 3: IT/OT Deployment

Milestone	Completion Date
Construction standards for private network expansion	June 2020
Substation fiber termination using developed network engineering and design standards	December 2020
TOMS vendor selection, procurement, and project kickoff	December 2020
DMX equipment vendor testing	February 2021
DMX vendor selection	March 2021
INOC Assessment	April 2021
Data Management Phase 1	June 2021
Enterprise Services Phase 1	June 2021

<u>Objective #2</u> - Optimize system demand by facilitating consumer price responsiveness.

<u>VVO:</u>

- The VVO/CVR program intelligently switches reactive power and voltage support devices to reduce losses, improve power factor and reduce demand in a way that the system previously was unable to do. This program is designed to provide peak and demand savings to customers, without them having to take any active steps.
- The Company anticipates that by the end of calendar year 2021 it will have completed 39 upgrades for VVO/CVR on a total of 39 of its feeders which represents 3% of its total feeders in the Company's service territory.

Table 4: VVO Deployment

Milestone	**CY19**	**CY20**	**CY21**
VVO Annual Feeders Installed	6	6	27
Cumulative Feeders with VVO	6	12	39
Percentage of feeders with VVO	1%	1%	3%

- The Company completed its measurement and verification process in winter 2020/21 at the Stoughton substation and began the M&V process at the East Methuen substation in March 2021.
- For the Stoughton substation winter period M&V, regression estimates indicate a statistically significant change in energy use associated with VVO, with 170 MWh (0.52%) energy savings realized during the winter 2020/21 M&V period.67 Regression estimates indicate that there were statistically significant reductions in energy use during peak energy hours, although there were statistically significant increases in energy use during off-peak energy hours. Peak energy savings totaled to 228 MWh (1.37%) as compared to an increase in off-peak energy of 49 MWh.
- Energy savings of 170 MWh realized during the winter 2020/21 M&V period yielded an 84 short ton reduction in CO_2 emissions, a 54 lb. reduction in NOX emissions, and a 14 lb. reduction in SO_2 emissions.

<u>ADMS:</u>

- The ADMS system helps optimize system demand by creating a more efficient electric system with more real-time monitoring and control, better-managed system voltage and fewer losses. It centralizes data, visualization, monitoring, control and automation capabilities, maximizing operational process efficiencies. The ADMS further enables operators to simulate the future state of the grid in abnormal configurations to optimize grid asset utilization.
- Progress on the ADMS was shared earlier in the section.
- Investments in ADMS that support the Company's programs/ initiatives (outside of grid modernization) include:
  - The Company's energy efficiency three-year plan includes several demand response programs that offer price signals to customers to reduce or shift their energy consumption during system peak events. These programs for both residential and commercial customers enable customers to utilize their flexible energy resources, including backup generators, energy storage, wi-fi thermostats, and EVs, for grid services.
  - The Company's off-peak EV charging rebate program, which offers price incentives to encourage a customer to charge their EV at off-peak times.

Communications, IT/OT:

- Investment in enabling infrastructure continues to progress to support enablement of the Feeder Monitor, VVO/CVR and ADMS investments which will support optimizing system demand. While the broader communications plan and investments continue, interim investments to enable grid visibility and command and control have been delivered which allow for the activation and operation of our VVO capabilities. The enterprise integration platform has been established to support the ADMS Phase 1 and the data management platform is being enabled to support the additional data and analytics needs.

Objective #3 - Interconnect and integrate DERs.

ADA/FLISR/VVO/Feeder Monitors:

- All investments help directly and indirectly interconnect and integrate DERs by providing more real-time information about the distribution system. The increased operational system awareness from the deployment of feeder monitors, ADA and CVR/VVO collectively allows for much more data to be used in DG distribution system impact studies.
- The Company has been able to extend investment capabilities to support this objective through the Affected System Operator (ASO) capacitors. Specifically, the VVO/CVR technologies have been leveraged to offset costly system upgrades. A transmission system impact study report was undertaken in the Company's Western MA DER interconnection cluster study. This consisted of a total DER applying for interconnection into the Western MA distribution system is 787 MW. The sensing and control in these devices will allow the Company to deploy the capacitors and optimize voltages based on system conditions whether to mitigate transmission substation voltage issue during certain periods of the year, provide volt-var optimization during certain periods of the year, and do both during other periods of the year. After the Company gains expertise in managing the capacitors for this intended use case, volt-var optimization can be enabled and the dual benefits can be obtained.
- Since the Company began to deploy these key investments, we have experienced the following benefits to help us integrate DER's onto the system; Feeder Monitors continue to allow electric distribution planners to better assess DER areas and identify more accurately when upgrades are needed to maintain reliable service to our customers; ADA/FLISR help maintain a stable and reliable distribution system within areas by isolating faults that can occur through DER overload ; VVO/CVR have indirectly benefited the Company in highly DG interconnected regions. By utilizing VVO smart capacitors, they are strategically installed on feeders to help manage voltage levels and minimize the impact of voltage instability customers can face due to the levels of DER penetration onto the distribution system. See Incremental section under VVO (ASO investment).

ADMS:

- The ADMS/DSCADA solution enables advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.
- Investments that support the Company's programs/initiatives (outside of grid modernization) include:
    - Programmatic installation of zero sequence overvoltage protection schemes (i.e., 3V0)
    - The Company's participation in Department proceedings including discussions on innovative DG/DER planning and cost allocation methods (in docket D.P.U. 20-75)
    - The Company's collaboration with industry and other Massachusetts utilities through the Massachusetts Technical Standards Review Group for consideration of new technologies and alignment among the electric distribution companies on technical requirements.

Communications, IT/OT:

- The Company completed a strategic assessment of the communications and the IT/OT approach and finalized the portfolio of solutions for building this technology foundation and infrastructure cornerstone for delivering the capabilities of the proposed grid modernization investments, including CVR/VVO, ADA, feeder monitors, ADMS/DSCADA, and integrating DG. As a component of the strategy, National Grid identified short-term and long-term plans for building the enabling capabilities, platforms and communications necessary to achieve visibility, control and operation of the first term investments and to support the objective to interconnect and integrate DERs. While the broader communications plan and investments continue, planning and building these platforms to support this objective is a key foundational activity and investment.

3.2. Preauthorized/ Previously Deployed Technologies

This section presents National Grid's proposal for continued investment in preauthorized/ previously deployed technologies. The Company is requesting expedited approval for this group of projects so the project schedule can be maintained. Failure to approve these projects in a timely manner would result in scheduling delays and the possibility of increased cost.

The Company summarizes its proposal for each category of grid-facing investment and includes the following information for the Department's review:

- **Background:** Current state of technology, current limitations, and why the investment is needed
- **Goals and Objectives:** What the Company plans to accomplish and how the investment makes measurable progress on the Department's grid modernization objectives
- **Progress and Schedule**: Summary of progress on work completed to date and the proposed schedule for completion of work

- **Incremental:** Discussion of incremental nature of investments
- **Benefits**: Summary of the key benefits for customers, including any specific benefits for low-income customers and Environmental Justice Communities ("EJCs")
- **Budget:** Expected capital expenditures (CAPEX) and operating expenditures (OPEX) for the four-year plan period for each category of investment

3.2.1 Feeder Monitors

Background

The Company has been deploying head-end mainline Feeder Monitors which would be used to capture real time voltage, current and power quantities. The operations control center will use this information, as will electric system planners, to help optimize the control and design of the electric system. This increases the historic and live interval data improving the Company's situational awareness. While the electric system has operated without these data, the availability of such data is important to enabling the future modern electric grid, which will have increased requirements for reliability and the management of the proliferation of DERs. The dynamic impacts of DER on the distribution system's performance require a granular understanding of situational awareness to assure service is maintained within acceptable service quality standards in an efficient manner. In the absence of data, operators and distribution system planners must make conservative assumptions with respect to the coincidence of load and DER operation. This leads to more restrictive hosting capacity assessments and less than optimal operational actions. Feeder Monitors provide more accurate data for hosting capacity and maximum loading (i.e., heat map and hosting map) calculations, which benefit DG and other DER providers (e.g., EV charging stations) looking for the less DG-saturated, and therefore more economical, locations for their projects.

Goals and Objectives

Achieving the goals of the GMP will require interval monitoring on all primary distribution feeders, at least at the head of the feeder (i.e., at or near the substation) for compliance with voltage and protection requirements as customer DER adoption grows. The Company's standard practice for several years has been to deploy remote interval monitoring and control for new substations and feeders as part of the Company's Energy Management System ("EMS") Program.[14] Feeder Monitors are a cost-effective method of measuring current, voltage, and real and reactive power that can be deployed on feeders for which the Company otherwise does not have sufficient visibility. This will allow the distribution system to fill an information and awareness gap which will lead to efficient operation and

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[14] The Company's EMS Program is an effort to enable remote control and data acquisition on a variety of substation equipment (e.g., breakers, regulators, transformers), which can be managed by the Company's EMS.

maintenance, planning, and storm recovery, and result in lower costs to all the Company's customers by optimizing system performance.

Deployment Schedule

The main objective of the Feeder Monitor program is to acquire visibility at the feeder heads for feeders where the Company doesn't have visibility in EMS. The Company expects to accomplish this objective by end of CY2021. The secondary objective of the Feeder Monitor program is to be used as a tool for system planners to gain visibility along the feeders. Feeder Monitor deployment will be leveraged for step-down transformers distributed across its feeders. These transformers step down primary distribution voltages such as, 13.8KV to 4KV to serve local loads. These system designs are challenging to support operationally, and monitoring them will greatly help electric planning, as they are often points of congestion on the electric system due to their inherent current limitations. Adding low-cost Feeder Monitor Sensors to these areas will allow electric planning to better assess these areas, identify more accurately when upgrades will be necessary, and determine the most effective upgrade paths. This tool will remain an essential element of optimizing system demand, performance and control but will gradually decrease as the Company gains additional visibility into the grid through AMI.

Table 5: Feeder Monitor Deployment Schedule (CY19-CY26)

	CY19	CY20	CY21	CY22	CY23	CY24	CY25	CY26
Feeder Monitors	5	66	131	32	32	32	32	32
Feeders Monitors Cumulative	5	71	202	234	266	298	330	362

Incremental

As highlighted earlier the improved visibility through Feeder Monitor deployment accelerates and contributes to all three grid modernization objectives. It will remain an essential element of the Company's five-year strategy for the Company to optimize system performance and demand. In addition, the Company currently has step-down transformers distributed across its feeders. These system designs are challenging to support operationally, and monitoring them will greatly help electric planning, as they are often points of congestion on the electric system due to their inherent current limitations. Adding low-cost Feeder Monitors to these areas will allow electric planning to better assess these areas, identify more accurately when upgrades will be necessary, and determine the most effective upgrade paths. The Company anticipates development of the underground sensing technology which can introduce the deployment of Feeder Monitors and monitoring throughout the Company's distribution underground network. As AMI meter deployment begins to increase, visibility throughout feeders will increase, and can supersede the need for the improved visibility of the metered points and will minimize the number of Feeder Monitors deployed.

Benefits

Feeder Monitors provide Observability (monitoring and sensing) and Power Quality Management functionalities, which enable system planners and operators to design and operate the distribution system in a more flexible and efficient manner. These functionalities are foundational elements that support all other key grid modernization functionalities as summarized below.

- Feeder Monitors improve grid visibility and assist with determining outage locations and damages helping the Company route its crews to impacted locations which benefits customers.
- Feeder Monitors assist the operations control center (through the ADMS integration with real-time information) in performing system reconfiguration following contingencies and during peak loading periods.
- Feeder Monitors, in combination with other grid modernization investments, enable the Company to ensure voltage and loading compliance year-round across the distribution system, particularly in areas of the distribution system with high levels of DER penetration, which are necessary for safe and reliable electric service.
- The Company's electric planning group will benefit directly from the historical logging of data, which will assist in designing systems solutions. This will lead to a more efficiently planned system, using direct time interval feeder data, instead of annual and peak usage data as is done currently.
- Improved feeder visibility may help the Company reduce capital investments needed.
- All customers will benefit from this investment, including low-income customers and EJCs

Budget

Table 6 presents the four-year budget for Feeder Monitors. The costs shown include CAPEX and OPEX. OPEX costs including Telecoms "run the business" or "RTB", which accounts for the cost of device troubleshooting and third-party cellular fees necessary to communicate with the device's radio.[15]

[15] Telcom RTB costs are gradually reduced starting in CY25 as the Communications Network Strategy investments enable the Company to operate a private cellular network.

Table 6: Feeder Monitors – 4-Year Plan Budget

Feeder Monitors	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	**CY 2023**	**CY 2024**	**CY 2025**	**CY22-25**
CAPEX ($M)	$0.82	$0.85	$0.87	$0.89	**$3.43**
OPEX ($M)	$0.16	$0.17	$0.18	$0.20	**$0.71**
Total ($M)	**$0.98**	**$1.02**	**$1.05**	**$1.09**	**$4.14**

3.2.2 Volt-Var Optimization/Conservation Voltage Reduction

Background

VVO is an integrated approach to tie voltage and reactive power (“VAR”) control field devices (e.g. Advanced Capacitors and Regulators) together on one distribution feeder so the field devices work in unison to provide the most efficient delivery of power to the customer. Through VVO, the Company manages the voltage levels and reactive power to better manage delivery of power to customers. Utilizing VVO with CVR technology can flatten and lower feeder voltage profiles through the use of Feeder Monitors and centralized control of Advanced Capacitors and Regulators based on real-time system performance.

The VVO control schemes currently being deployed coordinate multiple voltage regulating devices on a feeder to achieve optimal CVR benefit. This lowering of feeder voltages benefits customers by reducing customer demand and energy use. Customer benefits are realized through reduced costs for electric energy and system capacity, which result in lower customer energy bills.

To accomplish the coordinated operation necessary to achieve VVO/CVR benefits, Advanced Capacitors and Regulators, including substation voltage regulating devices (i.e., Load Tap Changers (“LTC”) or individual phase regulators), line voltage regulators and capacitors must be deployed. In addition, Feeder Monitors will need to be added at the end of each feeder and at strategic points on the feeder to monitor power quality.

Goals and Objectives

The Company plans to continue to deploy VVO/CVR on targeted feeders where the benefits continue to justify the costs. The Company is currently utilizing a stand-alone VVO/CVR controller for its VVO deployments but anticipates transitioning to an ADMS-based VVO/CVR solution to reduce costs and gain efficiencies due to automation onto a single control platform with an “as switched” network model, allowing optimized solutions when the grid is in abnormal states. In Phase 3 of the ADMS deployment, the Company expects customer-level voltage information to be available through AMI and believes an incremental 1% reduction in energy and peak demand can be achieved if this more granular voltage data is used to fine tune the VVO control scheme.[16]

The additional operational data collected by automated capacitors and regulators, and displayed in an ADMS, should support the improved management of the distribution system which will assist in the integration of distributed resources. Actively maintaining proper voltage via intelligent centralized control will also improve feeder voltage performance, allowing for more DERs.

Deployment Schedule

The Company has developed a BCA Tool to rank the substations in its service territory according to the monetary benefit to the customer by deploying the VVO scheme.

The BCA tool enables the Company to quantify expected benefits on a given set of feeders for a specific substation. The tool has feeder characteristics such as loading, customer counts per customer type (residential or industrial), and voltage regulating device level data (i.e. station data, number of capacitors, number of regulators) that is relevant to VVO deployment. This information helps drive a cost assumption to deploy VVO on the device level which is then applied on the feeder level and combined with other feeders to represent a substation. Working on a substation level serves both to simplify the output and align with the program's goal to deploy on a substation basis.

The BCA tool uses net present value ("NPV") cost calculation and uses a percent energy reduction benefit to identify substations and feeders where VVO may be beneficial to deploy. Many of the inputs for the financials include: rate of return, weighted average cost of capital ("WACC"), tax rates, and depreciation values. In addition to NPV, the tool will show the average customer impact, as well as, the Company's expected Earnings Before Income Tax Expense ("EBIT").

The ADMS Core Functionality presented in Section 3.2.4 will be capable of supporting an integrated VVO/CVR application and the Company anticipates that a VVO/CVR application will be incorporated in the third phase of the ADMS project. The Company anticipates that VVO will be deployed at the following rates.

Table 7: VVO Deployment Schedule (CY19 – CY26)

Milestone	CY19	CY20	CY21	CY22	CY23	CY24	CY25	CY26
VVO Annual Feeders Installed	6	6	27	32	44	56	56	64
Cumulative Feeders with VVO	6	12	39	71	115	171	227	291
Percentage of feeders with VVO	1%	1%	3%	6%	10%	15%	20%	26%

[16] AEP Ohio is currently testing a new Utilidata VVO/CVR module that takes voltage data from AMI and applies proprietary algorithms to find the most relevant information for fine tuning a VVO scheme. This new technology has been deployed in 16 feeders and in its first 6 months of operation is yielding on average 1%+ incremental energy savings. Source: Utilidata, Case Study: Maximizing Grid Modernization Investments.

Incremental

The primary purpose of VVO/CVR is to reduce system demand in support of the grid modernization objective to optimize system demand. Every feeder deployment that produces a net positive benefit to cost differential will be a deployment that helps accelerate delivery of the Department's grid modernization objectives. The Company estimates that between 550 to 663 feeders (49% to 60% of feeders) will result in a positive benefit to cost differential based on calculations that assume AMI will be deployed and 1% incremental energy saving can be achieved. The Company expects to utilize the installation of smart capacitors for an Affected System Operator (ASO) program. This program is intended to minimize the impact customers face due to the levels of DER voltage penetration onto the distribution system. Without the ability to manage voltage more granularly, interconnection studies would impose substantial limitations on the pending DER, including for example, requiring expensive system upgrades or reducing the size of the DER that can be interconnected, which could make many DER projects uneconomic. The advanced controllers the Company is utilizing can integrate within a VVO scheme and will facilitate the deployment of VVO/CVR on all targeted feeders.

Benefits

VVO/CVR provides Power Quality Management functionality, which results in the benefit impacts summarized below.[7]

- Reduced Customer Energy Use and System Capacity Requirements by enabling the system operator to manage voltage impacts of renewable DG and operate distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand.
- Avoided Distribution-System Infrastructure (when coupled with ADA, ADMS, and other supporting solutions) due to the load optimization (i.e., ability of the system operator to autonomously or remotely control power flows on the distribution system, by maintaining voltage compliance across all times of the year and across the distribution system with various levels of DER penetration), rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.
- All customers will benefit from this investment, including low-income customers and EJCs.

Budget

Table 8 presents the 4-year budget for VVO/CVR. The Company estimates investing $76.44 million through CY 2025.

Table 8: VVO/CVR – 4-Year Plan Budget

VVO/CVR	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$10.55	$14.90	$19.46	$19.98	**$64.90**
OPEX ($M)	$1.60	$2.43	$3.42	$4.09	**$11.54**
Total ($M)	**$12.15**	**$17.32**	**$22.89**	**$24.08**	**$76.44**

3.2.3 Advanced Distribution Automation (ADA)

Background

The distribution system is generally a radial design, meaning that if the flow of electricity is interrupted at one location, all customers electrically downstream of that faulted location are interrupted as well. Reliable distribution system design utilizes protective devices such as fuses, breakers, and reclosers to interrupt faults and limit the number of customer interruptions as best as possible for any given fault. In addition, switches are placed at strategic locations along a feeder and where feeders can be connected to another feeder, so that faulted sections of a distribution feeder can be isolated and power can be re-directed to customers in undamaged areas.

Prior to having ADA, the initial clearing of electrical faults is done through the local protective control of reclosers and fuses, however the isolation of the faulted sections and the service restoration of customers was performed through the manual operation of switches in the field. Without the overlaying coordinated control scheme, an operator must first assess the extent of and determine the cause of an outage by dispatching crews. After crews investigate and report in, the operator can make a decision on how best to isolate the cause. This, again, involves dispatching crews to various location in a time-consuming fashion.

Distribution Automation, commonly referred to as FLISR, is a control scheme that incorporates telecommunications and advanced control of key switching devices. This scheme provides remote monitoring and operator control of field devices for normal operations and maintenance, while at the same time providing an automated response to system contingencies. Automated feeder tie points and protective devices (i.e., advanced reclosers) are coordinated to isolate faults and restore service to unaffected sections of a circuit without causing thermal or voltage violations. Coordination can be achieved via communications with an ADMS-based FLISR Application.

This automation scheme positively impacts the resulting customers interrupted and customer minutes of interruption (“CMI”) performance from a fault event that occurs within the zone of protection. Based on the results of FLISR in the Smart Energy Solutions pilot operated by the Company,[17] and a more recent operation during CY2021, expected benefits are an average 25% reduction in sustained outage frequency and duration on feeders with Advanced Reclosers and Breakers and a FLISR control scheme. Customer benefits are realized through reduced outages costs, which are monetized using the DOE ICE Calculator.

To accomplish the coordinated operation necessary to achieve FLISR benefits, manual switches and feeder ties need to be upgraded to Advanced Reclosers and Breakers at selected three-phase mainline locations to allow for automated switching in the case of a contingency event. In addition, monitoring (e.g., Sensors) are needed at the end of each feeder and at strategic points on the feeder to monitor loading.

Goals and Objectives

The Company is committed to providing reliable service to all customers. As a key service quality metric, reliability is measured by the frequency of customer interruptions and the duration of those interruptions. Metrics monitored include System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI").

The driver for FLISR is customer reliability, and the benefits and costs at each targeted location have been evaluated considering the expected impact on the frequency of sustained customer interruptions (i.e., SAIFI) and the duration of customer interruptions (i.e., SAIDI) that could be saved through automation.

Deployment Schedule

The proposed ADA plan assumes the current stand-alone ADA platform continues to be expanded through the next four years of the plan, after which an ADMS-based application is implemented. The ADMS Core Functionality presented in Section 3.2.4 will be capable of supporting an integrated application and the Company anticipates that an ADA application will be incorporated in the third phase of the ADMS project. The Company anticipates that ADA will be deployed at the following rates.

Table 9: ADA Deployment Schedule (CY19-CY26)

Milestone	CY19	CY20	CY21	CY22	CY23	CY24	CY25	CY26
FLISR Annual Feeder Installs	0	16	27	32	40	44	48	40
Schemes	0	8	14	16	20	22	24	20
Cumulative Feeders with FLISR	0	16	43	75	115	159	207	247
Percentage of feeders with FLISR	0%	1%	4%	7%	10%	14%	18%	22%

[17] *See* Worcester Smart Grid pilot, Appendix 10.8 to the Updated AMI Business Case.

Incremental

As highlighted earlier the primary objective of this solution is to optimize system performance through optimal levels of grid visibility, command and control, and self-healing. The Company believes that all FLISR scheme deployments with a net positive benefit to cost ratio are schemes that accelerate the grid modernization objective to optimize system performance. The change in climate weather and storm patterns has made it difficult for the Company to accurately estimate the total number of schemes that will result in the highest level of benefit to cost ratios for its customers. Currently the Company believes this will likely be less than 58% of its total feeder count.

Benefits

ADA provides Reliability Management functionality and enhances Observability (Monitoring and Sensing), Distribution Grid Control, and Grid Optimization functionalities. These functionalities result in the benefit impacts summarized below.

- OPEX Labor Efficiency (when coupled with ADMS and other supporting solutions) due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise.
- Reduced Outage Restoration Time (when coupled with ADMS and other supporting solutions) by enabling the system operator and control system to quickly locate and isolate a fault and restore power to unaffected customers rather than waiting for field crews to locate a fault and restore power. Benefits are based on the monetization of customer impacts as presented in the Department of Energy Interruption Cost Estimate ("DOE ICE") Calculator.
- Avoided D-System Infrastructure Cost (when coupled with VVO/CVR, ADMS, and other supporting solutions) due to load optimization (i.e., ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs), rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.
- Reduced DG Curtailment (when coupled with ADMS, DERMS, and other supporting solutions) due to the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance.
- Improved management of the distribution system through additional operational data collected by the automated switches, which will support optimizing system performance and assist in the interconnection of DG and potential integration of distributed resources. Increased system visibility reduces time to patrol for a fault.
- All customers will benefit from this investment, including low income customers and EJCs

Additional benefits could include:

- Increased system visibility reduces time to patrol for a fault
- Providing a platform for a more sustainable and storm (minor and major) capable grid for the future
- Operational effectiveness through remote monitoring and control capability

Budget

Table 10 presents the 4-year budget for ADA/FLISR. The Company estimates investing $42.58 million through CY 2025.

Table 10: ADA/FLISR – 4-Year Plan Budget

ADA/FLISR	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$7.06	$9.06	$10.23	$11.46	$37.81
OPEX ($M)	$0.86	$1.12	$1.30	$1.49	$4.77
Total ($M)	**$7.92**	**$10.18**	**$11.53**	**$12.95**	**$42.58**

3.2.4 Advanced Distribution Management System (ADMS)

Background

ADMS includes Distribution Supervisory Control and Data Acquisition ("DSCADA"), Outage Management System ("OMS"), and Distribution Management System ("DMS") advanced applications. They are intended to be implemented in an integrated fashion to enable the vision of a common network platform for operations. The advanced applications, as depicted in Figure 5, will enable Distribution Control Center operators to make more optimal system configuration decisions based on the actual constraints of the grid.

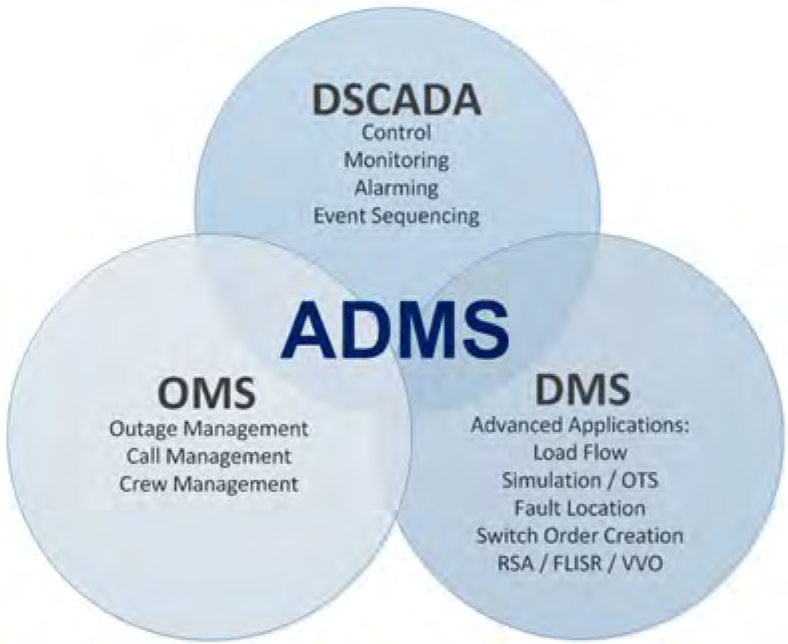


Figure 5: ADMS Key Components

The Company currently has a stand-alone OMS for all of New England. The existing computing hardware and software supporting the OMS was procured in 2009 and will be upgraded as part of the ADMS rollout. The Company also currently operates a Network Manager SCADA system that includes both T&D device data as well as EMS functionality utilized for transmission operations. A second similar distribution-specific SCADA ("DSCADA") will be rolled out as part of ADMS. This will allow for the integration of the DSCADA equipment status and device data with OMS to improve outage analysis and improve solution accuracy and granularity with advanced applications.

Currently, operators rely on static system models and the distribution status information in SCADA (where available) to make operations decisions. For planned and emergency feeder reconfigurations, the operators use historic data, such as seasonal peak loading information, to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER and locational variability is increasing. Larger DER are monitored via pole top recloser installations at the point of common coupling ("PCC"). This allows operators to see the net loading and impact at those points, but when the grid is in an abnormal state, the voltage and loading impacts across the feeder are not well known.

In addition, any advanced automation schemes are currently built as stand-alone functions. The operators can monitor the actions of the programs via the SCADA system, but they run independently based on “as-designed” feeder configurations rather than adapting to the real-time “as-switched” feeder configuration.[18] This means that these automated schemes may be disabled for any configuration of the distribution grid out of its normal “as-designed” state.

Finally, over the last decade, the Company has deployed a growing number of field devices integrated with the existing SCADA system, such that the amount of data brought back from distributed devices has increased significantly. The rollout of Advanced Capacitors and Regulators for VVO/CVR, DER monitoring via PCC reclosers, and Sensors is creating much faster data growth on the distribution side than ever before. This proliferation of remote telemetered devices on the distribution system is already straining the capacity of the existing SCADA system. As noted above, the existing SCADA system includes both T&D device data.

Goals and Objectives

The Company’s ADMS investment is an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid resulting in improved outage response, and increased efficiencies through automating and digitalizing multiple control center processes.

ADMS is currently being progressed to continue safe and reliable operations under growing system complexities such as dynamic load profiles from increasing levels of customer DER adoption. ADMS is a critical platform for the integration and operational management of DERs as their impact on grid performance grows. The ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices and DERs. ADMS will also incorporate AMI data as it becomes available. Examples of data utilized from AMI include power status notifications (e.g., power on / power off), voltage (e.g., high / low / partial power), and some demand data acquired by the system at a predetermined frequency.

ADMS will provide the Company’s operators with foundational functionalities such as load flow analysis, restoration switching analysis, switch order creation, state estimation, and fault location that are not available to Distribution Control Center operators today. When planning to reconfigure the grid, ADMS will allow operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach and ensue the most efficient switching that yields optimal power quality. DERs will be operationally integrated into the ADMS network model to allow operators to assess their effect on the grid, as well as leverage them for support where possible. In addition, ADMS will become the platform that coordinates multiple functions on a common “as-switched” network model. By incorporating

[18] “As-switched” refers to the network model the operators use (i.e., one-line diagrams and geographic maps of the electric grid) that are updated to represent the current state of the grid such as what switches are open and closed on the distribution grid.

control and automation capable grid devices (e.g., Advanced Capacitors and Regulators, VVO, and ADA) with the centralized ADMS platform, these technologies can operate in abnormal grid configurations, further supporting operations and adding value. Finally, the deployment of a new DSCADA system will enable management of the proliferation of data from remote telemetered devices on the distribution system to ensure continued reliability.

Supporting Projects

There are a number of supporting projects that are essential to the proper, optimal operation of the ADMS. These projects, described further in this section, are: (1) mobile outage dispatch, (2) remote terminal unit separation SCADA separation, (3) distribution PI historian, (4) geographic information system data enhancements.

Mobile Outage Dispatch

Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customers calls and predicted outage locations. They prioritize “trouble calls” and outages and assign them to appropriate field crews based on capability and location as optimally as possible. The Mobile Outage Dispatch will interface with OMS and allow field crews with mobile devices to efficiently receive outage jobs based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews, shorten “trouble calls” and outage response times, and improved outage information. Field crews will be able to update details concerning their actual time of arrival, increase insights into field conditions, digitization of incident details while on location, and provide estimated restoration times digitally rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near-real time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand.

The product development approach used is an iterative lean and agile development approach that will deliver a minimum viable product (MVP) with key features faster and benefits shortly after deployment. As new features are prioritized, built, and deployed, there will be incremental benefits delivered to the business and customers. Breaking out the solution into modular components will enable the team to build, test, learn, and adjust quickly to meet user requirements. This solution/product will be developed in the Azure cloud environment, React-Native framework, and integration will be completed through the use of middleware to connect to other existing core systems (e.g. STORMS, OMS, GIS, etc.). In addition, the team will leverage advanced technologies to enable digital and automated transactions to be performed on mobile devices. There are many opportunities to utilize this mobile solution to improve how planned and unplanned work are dispatched across the electric distribution business during blue sky and storm events.

The foundational features for mobile outage dispatch will be rolled out to selected field personnel to start and will ramp up over time, with a view to explore options to improve the outage restoration process (see Figure 6 below). Learnings will be applied towards developing the de-centralized process flows, and requirements for a full rollout. In summary, mobile outage dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

This mobile outage dispatch capability will be an extension to the existing mobile dispatch solution called OnMyWay, which is a four-year development project. The OnMyWay digital work dispatch solution will continue to grow over the next four years to achieve the product vision in being the central integrated mobile platform for the entire electric distribution business, improving business processes (e.g. manual and paper-based processes), and services to customers.

The OnMyWay minimum viable product (MVP) is currently in production and being used by the overhead line workforce across MA, RI, and NY. The MVP was built with six key features for overhead line workers to efficiently coordinate and manage short cycle overhead work. The six features are job finder, smart mapping, instant job update claim/update, digitized work packages, job management dashboard, and supervisor analytics tool. These MVP features were built to improve the existing process for how work is assigned and executed through heavily paper driven and time-consuming methods which requires many hand-offs. This process inhibits the Company's ability to enhance the customer experience and workforce engagement and effectiveness.

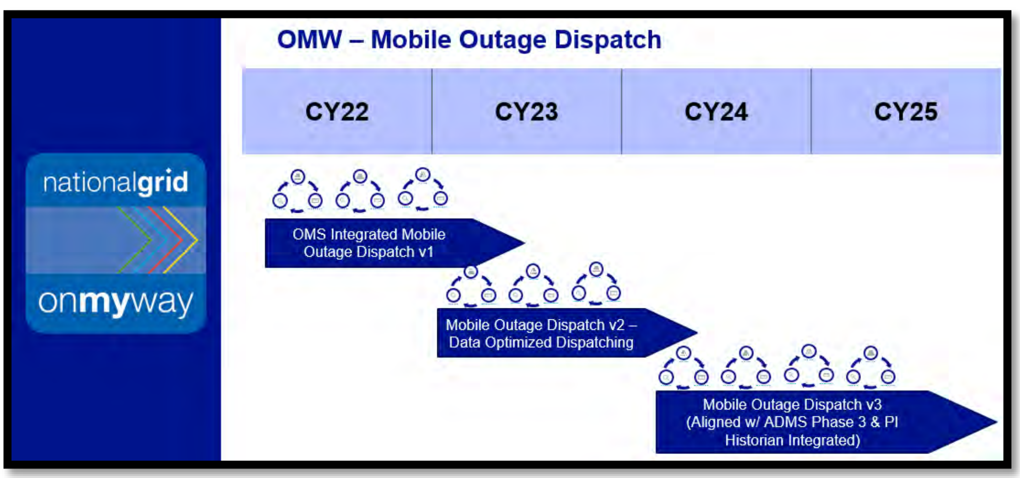


Figure 6: Mobile Outage Dispatch Roadmap and Timeline

Remote Terminal Unit Separation

The ADMS project has interdependencies with other enabling efforts as shown in Figure 7 below.

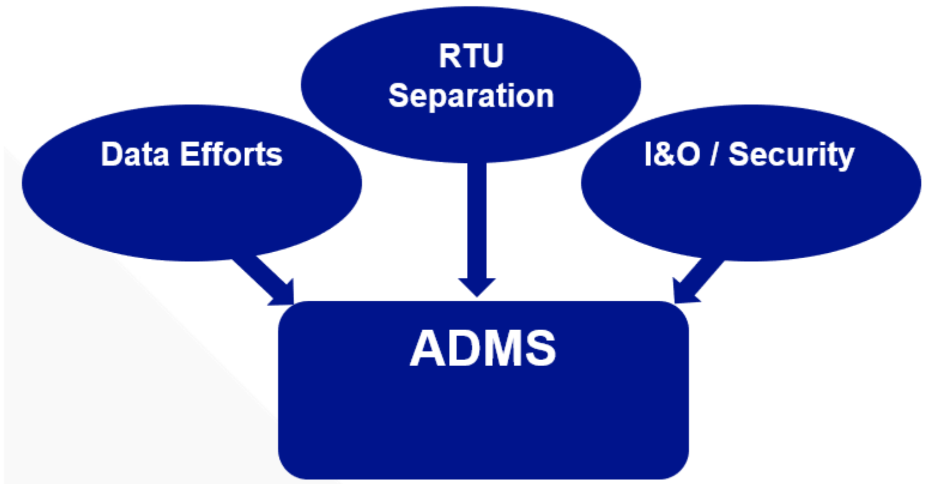


Figure 7: ADMS Interdependencies

An RTU is an interface device that collects information from smart devices in the field and packages it for transmission to the Company's SCADA system. The RTU Separation effort will facilitate the separation of T&D SCADA data by virtual (e.g., dual porting) and physical separation of the RTU and network allowing for integration with DSCADA and ADMS. This is necessary to make a clear divide for data and systems held to different security and compliance considerations. With the proposed separation of the SCADA system into a transmission-specific SCADA ("TSCADA") and DSCADA, any RTU presently sharing T&D equipment data points will be reconfigured either virtually or physically to communicate with the appropriate SCADA. Specific RTU separation work includes the following:

- Develop and document requirements and design for separate T&D RTU data communications ensuring consistency with present cyber security and North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") compliance requirements
- Define the point of demarcation between T&D networks considering present operating process and future state of distribution operations
- Explore all options, including industry benchmarking, for RTU separation and assess pros and cons to each approach

- Assess where RTU separation work can be bundled with other active substation work to achieve delivery efficiencies
- Assess state of communications to determine if upgrade is needed to support increase in data
- Separate RTUs and data as required based on outcomes from above efforts:
    - Procure required hardware
    - Engineer new RTU configurations
    - Implement both virtual and physical separation of the RTUs and related data
- Commissioning of new RTUs and RTU configuration changes from present SCADA to DSCADA will be carried out once the DSCADA module is implemented under the ADMS project

Distribution PI Historian

Plant Information (PI) Historian is a real-time data historian application with a highly efficient time-series database. This application can efficiently record data from process control systems (e.g., Distributed Control System, Programmable PLC) into a compressed time series database. Distribution system parameters are currently monitored by the existing SCADA system that feeds into PI Historian. The plan is to separate distribution data and set up a dedicated distribution-level PI Historian to interface with the distribution-specific SCADA (DSCADA) due to projected data growth from Advanced Field Devices and other grid modernization devices.

PI Historian records hundreds of thousands of pieces of raw operational data generated via SCADA systems, with most of the data being recorded every few seconds. Given the large number of intelligent electronic devices that will need to be monitored and controlled in an increasingly two-way power flow grid, the Historian's capacity and capabilities need to be expanded. The Company is developing plans to implement these upgrades as the Historian will be one of the main data sources feeding into various operational systems.

Geographic Information Systems (GIS) Data Enhancements

Geographic Information System (GIS) is a technology that combines the power of maps with the function of a database. As grid operations increasingly require granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality, GIS will be the foundation on which many of these systems are built. The Company utilizes GIS as its authoritative source for distribution asset information and as designed network configuration (i.e., "connected model"). GIS information is utilized in several business processes including distribution system project design, load flow modeling, outage management, and analysis models. While the existing GIS and data sets maintained by the Company have been fit-for-purpose to date, the introduction of new uses for GIS integration, such as for ADMS applications, requires change. Without addressing the data as well as system performance and functionality requirements, the Company cannot take full advantage of the benefits that ADMS and advanced analytics platforms offer.

Industry experience has shown that investment in data enhancement is a critical enabler for the efficient use of advanced grid modernization applications. The importance of a GIS integration with ADMS was confirmed through an internal ADMS assessment the Company's New York affiliate conducted on 15 feeders. The assessment clearly demonstrated that enhanced GIS data is necessary for successful network modelling. Reinforcing this perspective is the US Department of Energy's, Insights into Advanced Distribution Management Systems publication which notes that: "[t]he foundation of an ADMS is the data. The ADMS is a control hub, and it must have accurate data to correctly model your system. Data collection and maintenance in your GIS is critical to your ADMS implementation, and business processes to maintain clean data is just as important."[19]

Lessons learned from these industry and Company efforts have informed the Company's GIS implementation plans, which includes: (1) system enhancements, (2) data enhancements and (3) process review and improvement, described below.

Work to be completed between 2022 and 2025 includes:

System Enhancements (IT Resources)

- Configure and program GIS to accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics; facilitate capture of greater data and modelling granularity for underground distribution networks; and facilitate more granularity for low-voltage secondary distribution networks
- Develop substation modelling capability to support operations and planning processes
- Develop additional tools and improve existing toolsets used to manage data quality and processes in GIS
- Configure, develop and deploy next generation, vendor supported GIS and associated modern hardware (Phase 2)
- Configure and deploy additional system tools to allow export of Asset and Connected model to a standard format widely consumable by third party analytics and other toolsets (Phase 2)

Data Enhancements (Business Resources)

- Analyze and enhance existing data, including network connectivity, configuration, and equipment attribute-level values
- Identify and populate new asset types, including network connectivity, configuration, and attribute-level values
- Ensure complete population of DER interconnections in GIS and populate relevant customer equipment attributes including nameplate, manufacturer, make, and model information

[19] U.S. Department of Energy, *Insights into Advanced Distribution Management Systems,* 22 (February 2015), https://www.energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf

Process Review and Improvement (Business Resources)

- Review procedures and standards associated with the asset data life cycle
- Identify and implement changes to enhance processes, quality control, and reductions in cycle times
- Develop and implement data quality metrics and controls to facilitate continuous improvement

Deployment Schedule

This approach begins with the deployment of a foundational platform in Phase 1 on which future optimization applications can be integrated as illustrated in Figure 8. Benefits of a phased approach include:

- Allows for operations and support functions to become familiar with the use of baseline DMS applications in their daily work processes to improve operational efficiencies and awareness without disrupting critical processes
- Allows for the assessment of adoption of various functions and applications to help inform future phases and applications to maximize value add
- Phased approach is coordinated with GIS network model enhancement work to allow time for addition of all required elements and attributes to support advanced functionality as well as alignment with RTU separation work that supports the DSCADA

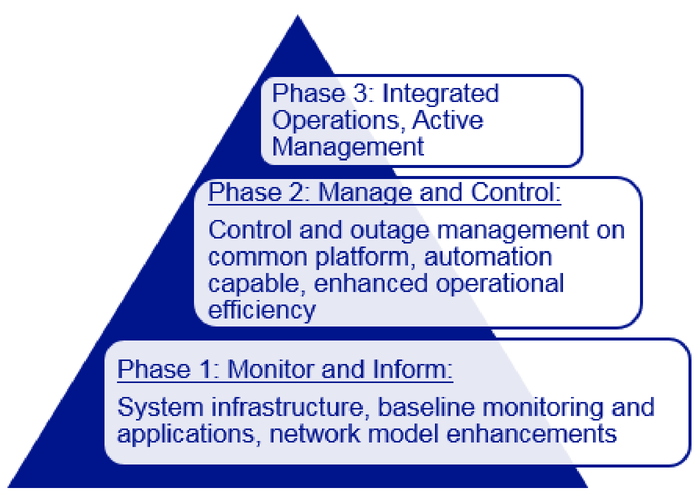


Figure 8: ADMS Deployment Phases

The ADMS phased approach involves implementing DMS applications and an upgrade to the Company's existing OMS production system into one common platform and network model. The project will implement a DSCADA by splitting the present SCADA system into separate TSCADA and DSCADA platforms. The resulting DSCADA system will be fully integrated with the DMS and OMS creating one common model-integrated ADMS.

The phases of the ADMS project are proposed as follows:

- Phase 1: Monitor and Inform (placed in service May 2021)
  - Define requirements and design
  - ADMS system infrastructure and network
  - Data expansion, population and centralization in ADMS for required functionality
  - Test and verify baseline applications functionality
  - Implementation of monitor and inform functionality via baseline DMS applications, load flow, restoration switching analysis, simulation mode, and experimental fault location.

- Phase 2: Manage and Control (planned in-service by May 2024)
  - Upgrade and refresh OMS incorporating functionality into common system and network model with DMS applications sharing data to improve outage visibility and response
  - Build DSCADA to support manage and control functionality for distribution devices
  - Interface with short-term load forecasting and mobile dispatch functions
  - Initial testing and implementation of more advanced automation capable applications such as VVO/CVR and FLISR
  - ADMS components (i.e., DSCADA, OMS, DMS apps) available utilizing single platform

- Phase 3: Integrated Operations, Active Management (planned in-service by December 2025)
  - Fully integrated system automation centralizing VVO/CVR and FLISR applications
  - Move towards active network management leveraging distributed resources and interfacing system data allowing:
    - Real-time DER control guided by short term load forecast and economic dispatch (when integrated with DERMS)
    - Publishing an "as-operated" system model to the Enterprise Integration Platform or future Data Lake to enable Advanced Analytics
    - Protection & Arc Flash Application: ADMS-based Protection & Arc Flash application to maintain safe and reliable service with increasing levels of customer DER adoption. This application would automatically check if protective devices can clear all faults anywhere on the feeder.

- There are many challenges associated with incorporating large amounts of real time data, complex network models, new operational processes, and a growing number of integrating systems. Therefore, the phased approach presented in Figure 9 will be implemented for the

ADMS project to better manage these challenges by building on a solid foundational platform in Phase 1.

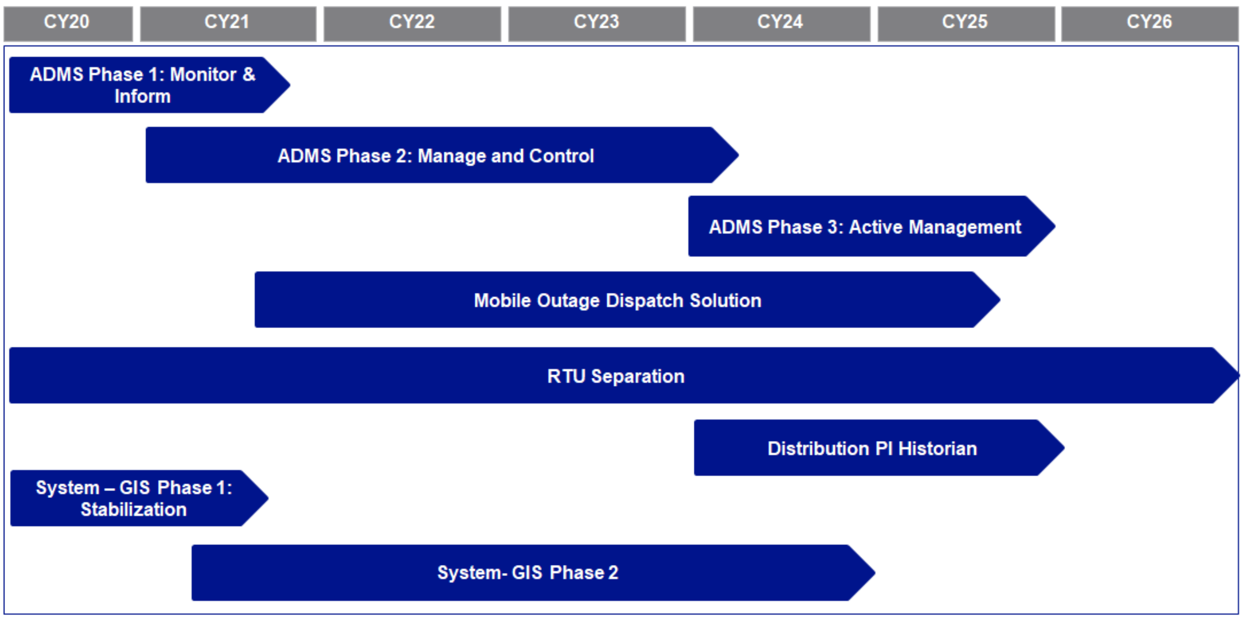


Figure 9: ADMS Phased Deployment

** Timeline reflects the overall program for all jurisdictions.

<u>Project Progress to Date:</u>

Engineering, Infrastructure and Data:

In 2020 the team worked on procuring hardware and software, and system design and build out. Physical and technical design models were completed. The building and configuration of a dedicated network for the ADMS system for local control center secure access between consoles and servers was completed and tested. The ADMS system environments were built out following internal standards to allow for proper backup and progression of software throughout environments. Solution testing and data preparation and readiness work was completed. Factory acceptance testing ("FAT") was carried out on the ADMS Phase 1 system. As part of FAT, the team architected the data migration in conjunction with internal data owners of several key ADMS data elements and worked towards identifying areas of data shortfalls. The team worked on the development and successful completion of more than 500 system test procedures designed to test ADMS system functions. The team established frameworks for monitoring and managing increasing DER assets into the operational network model. Feeder readiness was conducted on a predetermined set of feeders and these feeders were progressed through a series of data and engineering analysis until they were deemed test ready.

As part of the overall corporate data strategy, the data team began to coordinate and refine necessary data processes. GIS improvements and data hardening are in-progress. Field surveys to acquire digital photographs of the Massachusetts electric distribution system were completed. 83.5% of the available MA electric distribution poles accessible from public right of way were acquired, resulting in over 605,000 digital photos. The data team continues to review and update data, completing over 5800 overhead and underground circuit miles. In addition, the required changes to baseline GIS are underway with an anticipated September 2021 deployment. This work will allow for new asset types, new equipment, expanded attributes and characteristics. The data team also established a continuous-monitoring process to ensure that the cleansed data remains at the appropriate level of quality and completeness. Lastly, changes needed to extract and update information required for ADMS functionality were completed.

Process Analysis and Design:

A thorough analysis of business processes was carried out to ensure that all ADMS capabilities were correctly integrated into current control room workflows and procedures. An as-is analysis was completed and to-be processes including ADMS functions were built. The work involved project team support and input from various business groups who perform the functions affected by ADMS. A Change Impact Analysis ("CIA") was conducted on the new ADMS processes to identify and analyze the upcoming changes and rank their impact to stakeholders. This alignment will ensure that the ADMS program is integrated with the as-is business functions and identified areas of improvements with future state business functions. This work will also ensure that the implementation of ADMS into the control room will be seamless and effective for the users and deliver intended benefits.

Change Management:

The Change Management Office ("CMO") is an integral component of the ADMS program to prepare the business and other stakeholders for the deployment of this new tool. The CMO centered its effort in understanding the stakeholders and the impact of changes they face to develop a strategy and approach that addresses their needs.

During the Phase 1 program the team sat down with various key stakeholders from different groups to listen to their current understanding of the program, their concerns and their questions, to get a pulse of the current sentiments. The CMO developed a holistic approach in promoting stakeholders' engagement throughout the program, in supporting the business to reduce go-live risks through the business readiness approach and in driving adoption and proficiency of the ADMS system by the stakeholders to maximize benefit realization through training.

A CIA was conducted on the new ADMS processes to identify and analyze the upcoming changes and rank their impact to stakeholders, in conjunction with the business process work.

The majority of ADMS end users in the Phase 1 implementation are located in the control center. Given the 24/7 operations nature of their work, and the criticality of their role in keeping the lights on, a training strategy accommodating their shifts and potential storm duty roles was developed. Ongoing analysis and assessments helped build a comprehensive training curriculum and training materials which are centered around the new ADMS functionalities and processes to help users understand how their roles are changing.

Governance, controls and process:

Creation of the project governance structure set the ADMS program up for success by establishing how decisions would be made and who needed to be involved in the decision-making process. Guidelines and procedures were created to assist in managing the project. This framework assisted in resolving obstacles and issues that can block strategic success.

The addition of several key performance indicators ("KPIs") allowed the team to gain valuable insight to several areas of the project and provide transparency for all stakeholders.

Incremental

As highlighted earlier, ADMS is an integral part in accelerating all three grid modernization objectives and should be treated as incremental until the program is complete.

Benefits

ADMS primarily provides Grid Optimization and Operational Analysis and Forecasting functionalities, but ADMS also supports or enhances a number of other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Distribution Grid Control, Distribution System Representation (Network Models), Reliability, and DER Operational Control.[7] Grid Optimization functionality results in a number of benefit impacts summarized below.

- Avoided Legacy OPEX Investments by avoiding the cost of a standalone OMS license in the future. Without investment in an integrated ADMS software package, which includes OMS functionality, the Company would need to continue to maintain its existing standalone OMS software license. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as "standalone OMS license savings" (see Section 4.2.3: Benefit Estimation in the GMP Business Case).
- Avoided Legacy CAPEX Investments by avoiding the cost of a standalone VVO/CVR license for existing deployments. Without investment in an integrated ADMS-based VVO/CVR application, the Company would need to continue to maintain its existing standalone VVO/CVR software license. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as "standalone VVO/CVR license savings (existing).

- OPEX Labor Efficiency (when coupled with ADA and other supporting solutions) due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise
- Avoided Distribution System Infrastructure Cost (when coupled with VVO/CVR, ADA, and other supporting solutions) due to load optimization (i.e., ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs), rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption
- Reduced Outage Restoration Time (when coupled with ADA and other supporting solutions) by enabling the system operator to quickly locate and isolate a fault and restore power rather than waiting for field crews to locate a fault and restore power. Prior to the deployment of FLISR, ADMS will also enable the system operator to quickly generate efficient and optimal switch orders, which can help restore power faster by ability to simulate the grid in future abnormal states leveraging distribution load flow and incorporating DERs will optimize grid configurations maximizing asset utilization and reducing waste.
- Upgrades OMS into ADMS and integrates real time outage notification status from telemetered equipment into the OMS, which reduces duplication of efforts in verifying outages and updating outage time after the event
- Benefits are based on the monetization of customer impacts as presented in the DOE ICE Calculator.[17]
- Reduced DG Curtailment (when coupled with ADA, DERMS, and other supporting solutions) due to the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance
- Centralizes visualization, monitoring and control on a common network model with all device data, real time data, ratings and setting data, providing a "single pane of glass" to support increased efficiencies and digitalization of processes.
- Creates platform and network model to support reliability aspects of interfacing DERMS and other future functionalities to integrate DER.

Specific benefits have been quantified in *Section 4.2 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 4.3 Qualitative Assessment*.

GIS provides Distribution System Representation (Network Models) functionality, which provides a topological model of the physical distribution system and customer and DER connectivity. This functionality is a foundational element and supports all other key functionalities. In addition, the Distribution System Representation (Network Models) functionality results in the benefit impacts summarized below.

- OPEX Labor Efficiency due to increased automation, reduction in model correction, and other work related to correctly, completely, and timely updating system data. Without this project, the Company estimates a need to increase its enduring labor spend to comply with emerging data needs and timelines. This significant labor increase would be required to create and maintain the various network models used for distribution system planning and operational models. This OPEX Labor Efficiency benefit is included in the GMP BCA as "avoided GIS network model labor" (see *Section 4.3: Benefit Estimation* in the GMP Business Case).

- Implementing the GIS Data Enhancement project will enable network models to be developed consistently and efficiently for distribution system planning, hosting capacity analysis, and operations utilizing ADMS. By providing accurate data with the appropriate level of granularity, the maintenance of system models can be further automated and refreshed more frequently to provide more timely and accurate system assessments. These efforts are foundational to enable the desired granular management of the grid envisioned in this GMP.
- Improved monitoring and control may help the company reduce capital investments that will help reduce bills for all customers.

Budget

Table 11 presents the 4-year budget for ADMS. The Company estimates investing $60.43 million through CY2025.

Table 11: ADMS – 4-Year Plan Budget

ADMS	Yr 1	Yr 2	Yr 3	Yr4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
ADMS Core Functionality CAPEX	$11.09	$6.57	$2.41	$1.59	**$21.66**
ADMS Core Functionality OPEX	$2.62	$3.32	$3.44	$3.35	**$12.74**
Mobile Dispatch CAPEX	$2.84	$2.92	$2.00	$0.26	**$8.01**
Mobile Dispatch OPEX	$0.71	$0.73	$0.87	$0.63	**$2.94**
RTU Separation CAPEX	$1.20	$1.23	$1.26	$1.30	**$5.00**
RTU Separation OPEX	$0.10	$0.10	$0.11	$0.11	**$0.42**
Distribution PI Historian CAPEX	$0.70	$0.05	$-	$-	**$0.75**
Distribution PI Historian OPEX	$0.24	$0.13	$0.12	$0.12	**$0.62**
GIS CAPEX	$2.59	$2.65	$1.03	$-	**$6.27**
GIS OPEX	$0.50	$0.83	$0.15	$0.54	**$2.03**
Total ($M)	**$22.59**	**$18.53**	**$11.39**	**$7.90**	**$60.43**

3.2.5 Information/Operational Technology (IT/OT), Communications

Background

A fundamental component of grid modernization is a systems architectural framework that can deliver “any data, any service, anytime.” Building this technology foundation is at the infrastructure cornerstone for delivering the capabilities of the proposed grid modernization investments, including AMI, CVR/VVO, ADA, feeder monitors, ADMS/DSCADA, CLM and integrating DG. The primary components of these investments include:

- IT/OT: This refers to internal investments made integrating all the above systems together, as well as integrating the Company’s existing systems to new ones. Comprehensive data management, integration services, cybersecurity and data analytical functions are included.

- Communications: This includes all infrastructure to connect National Grid IT/OT infrastructure with field devices in the service territory. The infrastructure consists of additional backhaul networks, substation fiber installations, a multi-tiered field based wireless communication network, and radios for devices without embedded communications.

Additional detail is provided in the following sections. Enterprise Architecture covers the Company's strategic approach, while the details of the objectives, schedule and benefits are described for the remaining components. Followed by this, is a summary of the cybersecurity initiative.

Enterprise Architecture

The Company has completed the business capability maturity assessment, applications mapping to capability model, and use case definitions to identify opportunities and dependencies. The program level conceptual solution has been established to address the needs of the Enterprise Integration Platform and Data Management. As part of these initial efforts, the Company completed an architecture assessment of the current integration tools in use, and their fitment for the grid modernization investments. In addition, the Enterprise Service Bus (part of Enterprise Integration Platform) has been selected. The foundational Enterprise Integration Platform has been deployed in May 2021 and the initial set of integrations to support transactions for the ADMS went into service. An integration roadmap has also been created that identifies the strategic integration needs for grid modernization and provides direction on the methods and patterns required to provide the required capability for current and future processes. The Data Management effort was initiated in 2020 and is expected to deploy the platform in October 2021 with Snowflake software as the central repository.

Figure 10 below illustrates how the on-going investments in Underlying IT Infrastructure interact with each other and with other GMP investments. Arrows and lines indicate integrations.

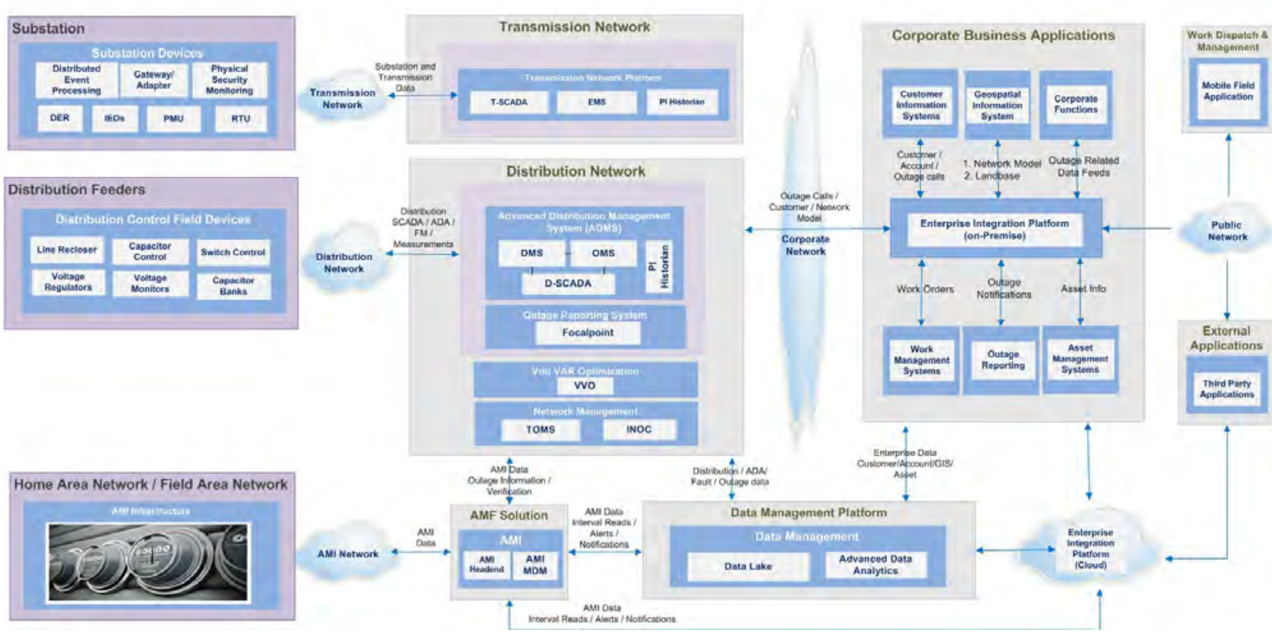


Figure 10: Grid Modernization IT Conceptual View

3.2.5.1 Enterprise Integration Services/Comprehensive Integration Services (CIS)

Background

CIS is the middleware that is required to move data between systems, automate and manage business processes, transfer files between entities and enable real-time and batch integration of data. National Grid has been developing these capabilities to enable real time integration, automation and orchestration of business processes enterprise-wide for existing legacy systems, and implementation of new systems building on process and systems efficiencies, needed for grid modernization.

The Company has established an enterprise standard for CIS. Some of the components that make up a CIS are: an enterprise service bus (ESB) which delivers a standards-based integration where performance, scalability and reliability are critical requirements; business process management (BPM); managed file transfer; business activity monitoring; and complex events processing.

Goals and Objectives

Future grid operations will require comprehensive interaction between various systems and applications. This interaction is securely and reliably achieved through the implementation of an Enterprise Integration Platform (A full set of capabilities that includes an Enterprise Service Bus and other tools and components to support Comprehensive Integration Services). Using a variety of integration patterns to cover diverse needs for security, volume (or throughput), speed (or latency), persistence (for auditing) and reliability, the Enterprise Integration Platform orchestrates complex operational processes across the system and application landscape. The Enterprise Integration Platform also provides the key function of periodically transporting data, securely, from source systems and applications to the Data Management Platform.

Investments in a modern integration platform will improve the reliability, scalability, security, efficiency, and diagnostics capability of the grid network. It will provide support for secure, efficient, performant and traceable transfer of data between external and National Grid IT systems. This will enable National Grid to perform with better efficiency and scale.

Grid modernization applications will leverage the Enterprise Integration Platform to integrate various objects within and outside the Company and enable secure exchange of information between systems, services, and devices. This investment will provide all the necessary integrations between applications such as ADMS, Telecommunications Operations Management System (TOMS), Active Resource Integration (ARI), Load Forecasting and VVO/CVR, with corporate applications such as GIS, Customer and external applications. Integration patterns[20] include Real-time Integration Patterns using MuleSoft, and File Transfers These patterns are essential to ensure consistency across the integration needs and implementations mechanisms. Figure 11 illustrates some of the integration data flows planned to be implemented for ADMS and related systems

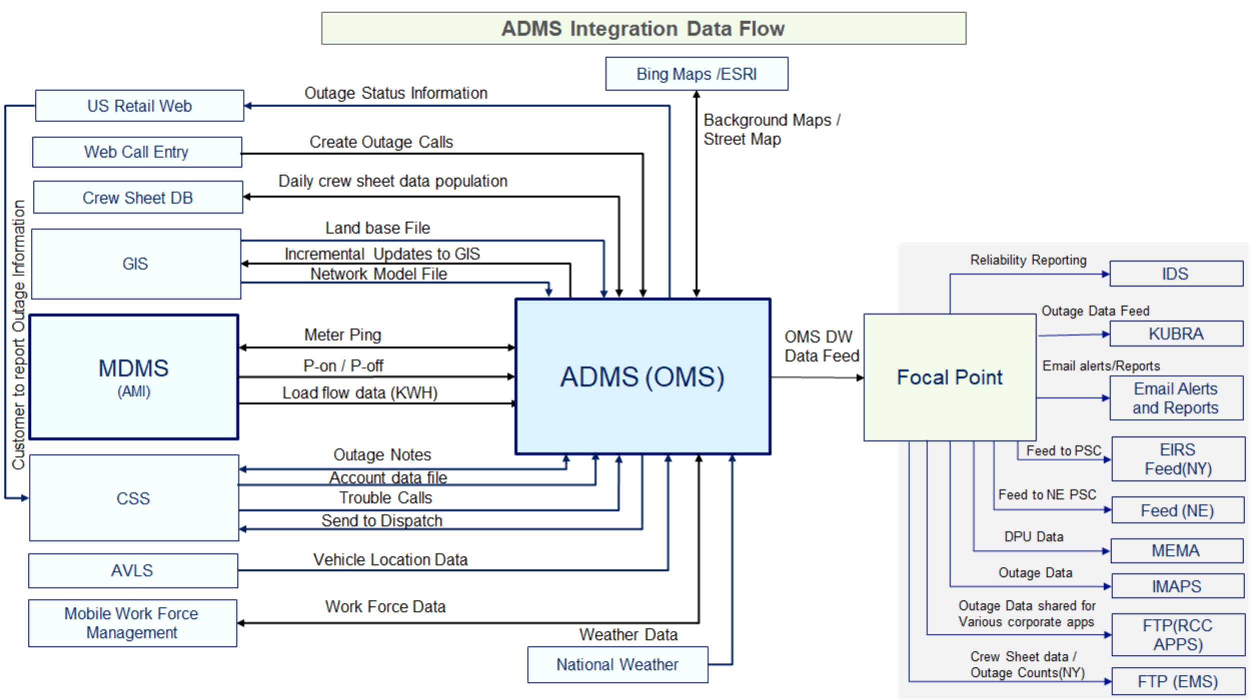


Figure 11: ADMS Data Flow Diagram

[20] Integration patterns are defined as combinations of security, volume (or throughput), speed (or latency), persistence (for auditing), reliability, and source and target applications.

The Enterprise Integration Platform investment will equip the business with the latest, industry standard toolset for application integration. Integrations required for the entire grid modernization program are spread across multiple system-based initiatives including various Company applications (e.g., ADMS, GIS, TOMS, VVO/CVR, PI historians). Figure 12 summarizes the resulting capabilities and expected outcomes from this integration.

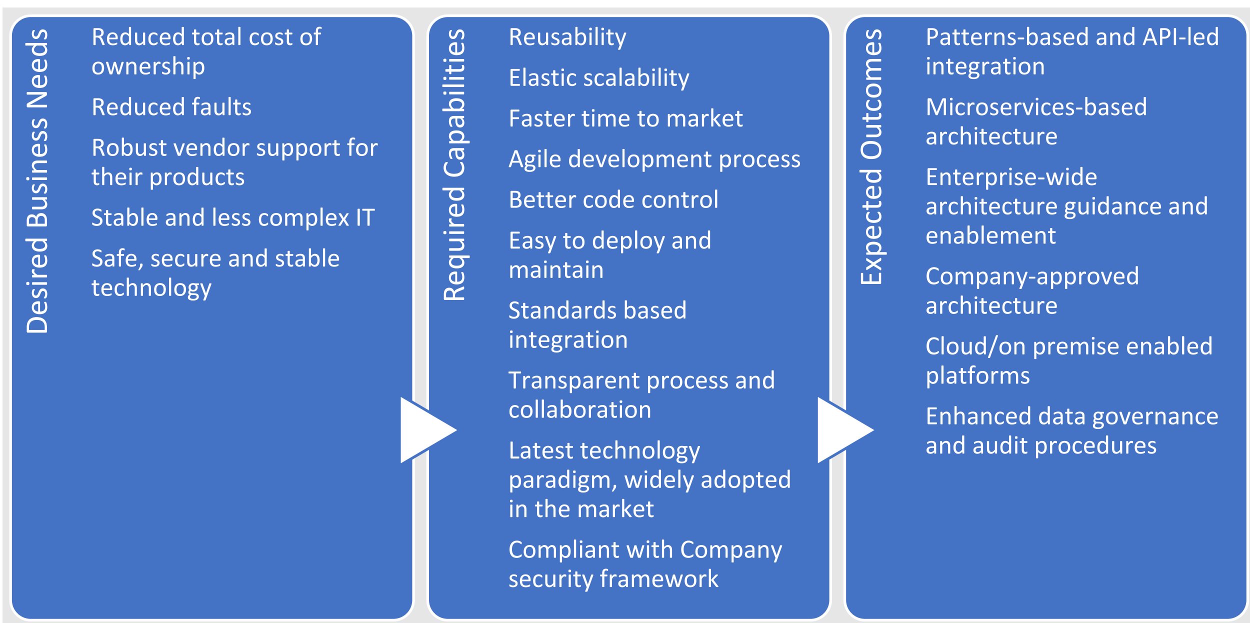


Figure 12: Needs, Capabilities, and Expected Outcomes for Enterprise Integration Platform[21]

Examples of data exchanged across the various interfaces being built includes, but is not limited to: Customer Account Information, Network Model, Land Base, Load Forecasts, and Outages. Each of these data sets will be assessed for Critical Energy Infrastructure Information (CEII) and Personal Identifiable Information (PII) classification, and approved Data Protection measures will be included in the integration patterns.

Deployment Schedule

This project is being delivered in a three-phased approach as described below:

[21] Microservices-based Architecture refers to a variant of the service-oriented architecture structural style, which arranges an application as a collection of loosely coupled services. In a microservices architecture, services are fine-grained and the protocols are lightweight.

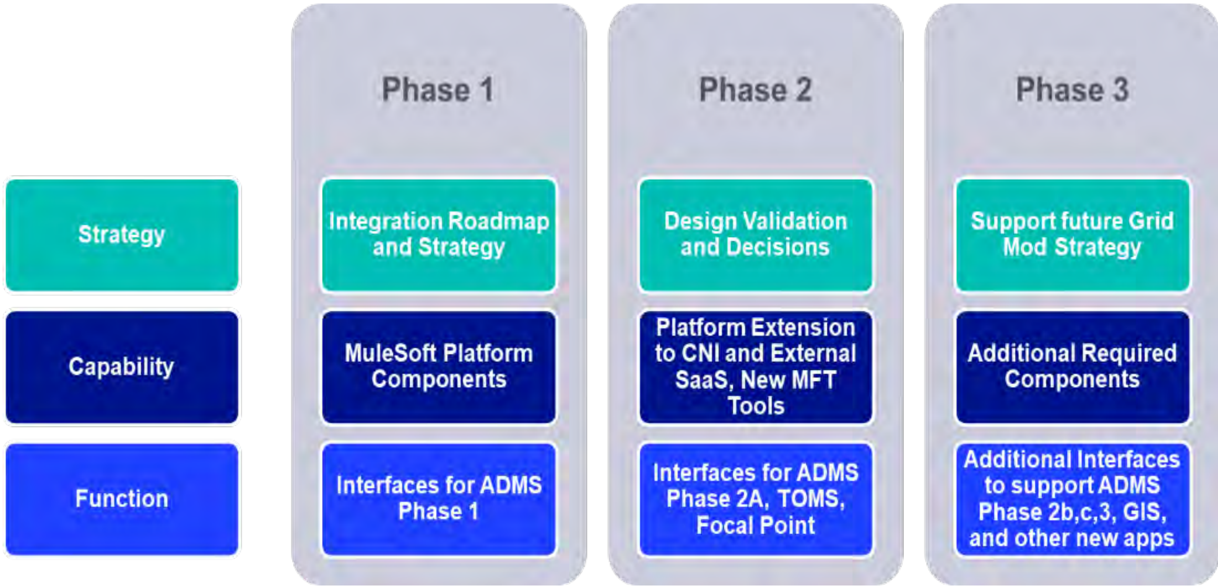


Figure 13: Three Phased Approach

As a part of Phase 1 Integration Services, the project has completed the setup of the core MuleSoft Enterprise Integration Platform, which is the foundation on which the integrations to enable grid modernization will be delivered. Multiple environments to support development, test and production have been provisioned. The platform components include Enterprise Service Repository, Business Activity Monitor, Complex Event Processor, Connectors/Adapters, Cloud Integration Platform, and Application Program Interface (API) Management. In addition to setting up this foundational capability in Phase 1, integrations across ADMS, GIS, and Customer Service System (CSS) have been deployed to align with overall grid modernization integration requirements.

In Phase 2 of Integration Services, additional integrations that are required across the CNI boundary will be delivered. This will be accomplished by delivering new integration patterns that comply with the security requirements for interactions with CNI systems. This phase will include an upgrade/migration of legacy interfaces to the modern MuleSoft platform and new interfaces for TOMS and Focal Point applications. Phase 2 will also deploy modern tools for Managed File Transfers (MFT) and integration patterns for external SaaS platforms.

Phase 3 of Integration Services will utilize the foundational platform and supporting tools to deploy the future set of integrations for advanced capabilities being delivered by the ADMS project, GIS and other new applications and systems.

The following chart provides and overview of the deployment schedule.

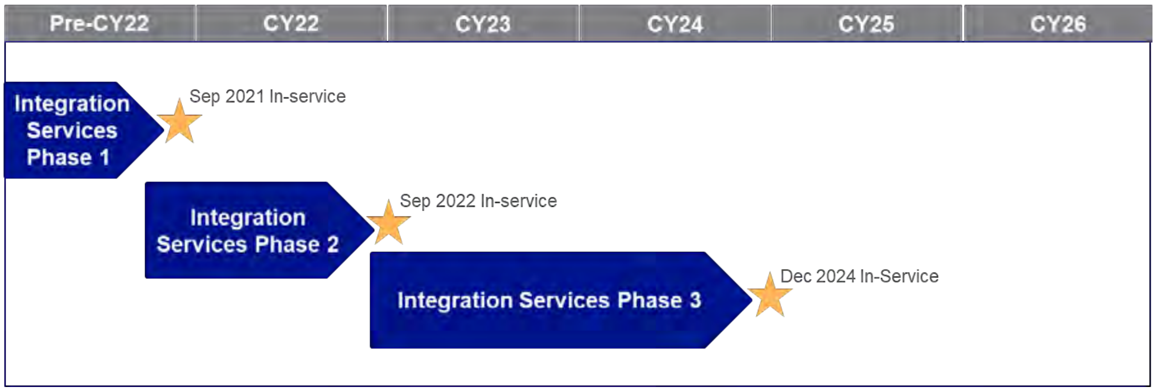


Figure 14: Three Phase Deployment Schedule

Incremental

With the Enterprise Integration Platform setup and phased delivery approach the project provides a key element of underlying infrastructure to support integrated business operations driven by the Department's grid modernization objectives. Common building blocks such as modern Application Programming Interfaces (APIs) provide the capability to create new interfaces to support the more advanced integrations required between applications to support more modern business operations.

Benefits

By delivering core enabling integration infrastructure and services across the grid modernization investments, this project will provide the following benefits towards ongoing integrated, secure, scalable operation of business capabilities:

- Flexibility to integrate grid modernization applications with DER developer and even customer systems that leverage remote monitoring and control capabilities for improved reliability.
- Secure gateway for integrating external services rendered over Cloud or by third parties that are outside the National Grid network. Grid modernization relies on effective participation of third parties, including customers, for advanced use cases through integrated systems. The secure gateway ensures protection of IT assets both for the Company as well as its customers and other third parties using the Cloud.
- User productivity by leveraging and extending services utilizing the most appropriate protocol and integration standards (e.g. lightweight APIs for Mobile and Rich Web consumption). This improves the ability to handle the high-volume, low-latency requirements for integration between grid modernization applications.
- Provide end-to-end traceability and audit and diagnostic capability (via analyze logs) and alerting for operational efficiency, which helps improve reliability of operations

Budget

Table 11 presents the 4-year budget for Enterprise Integration Services/Comprehensive Integration Services (CIS). The Company estimates investing $8.67 million through CY 2025.

Table 11: Enterprise Integration Services/ CIS – 4-Year Plan Budget

Enterprise Integration Services/ CIS	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$2.51	$1.12	$1.29	$-	**$4.91**
OPEX ($M)	$0.38	$1.23	$1.21	$0.93	**$3.75**
Total ($M)	**$2.89**	**$2.35**	**$2.50**	**$0.93**	**$8.67**

3.2.5.2 Data Management/Enterprise Analytics (EA)

Background

Managing the distribution system more granularly to safely, reliably, and cost effectively meet customer's evolving expectations will depend on how well the Company can manage, analyze, and share underlying information or data. Managing high levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices, advanced meters, and other technologies, there will be an enormous growth of incoming data. The investments in Underlying IT Infrastructure are necessary to fully unlock the value of advanced technologies and techniques like artificial intelligence or advanced analytics, which require that system and customer data is fit-for-purpose and readily available.

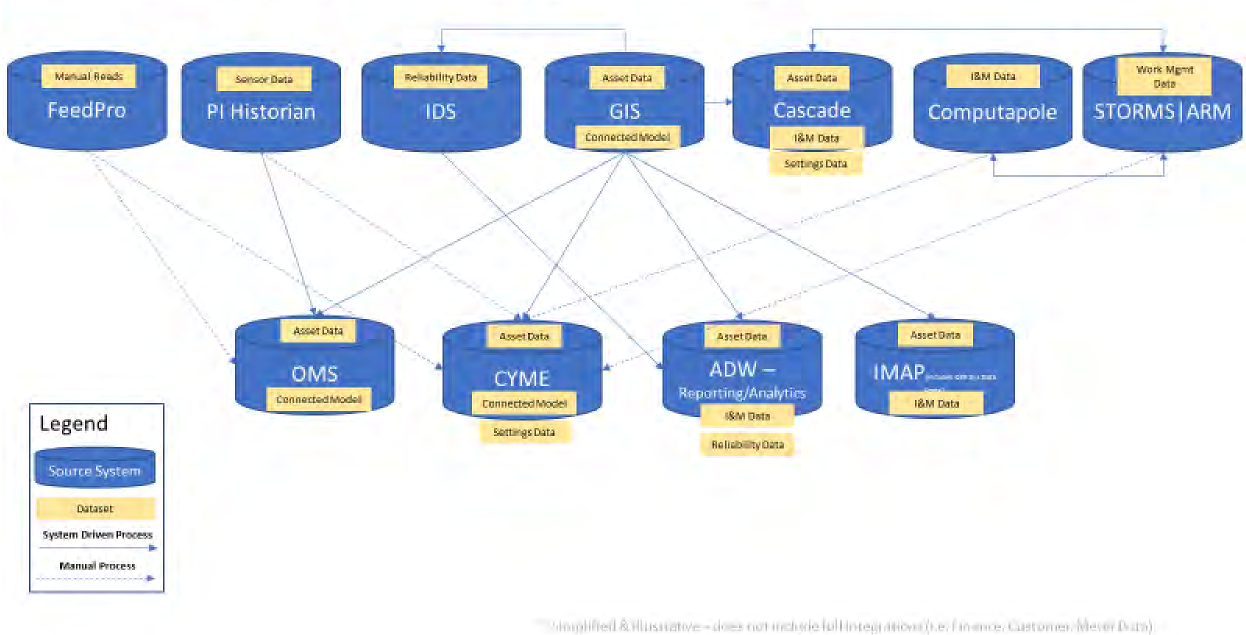
It is critical that accurate, timely, and consistent information flows seamlessly and continuously across boundaries. Current techniques for managing information is siloed and often manual. Deploying a "Data Management Platform" capability as illustrated in Figure 15 and moving toward an International Electrotechnical Commission Common Information Model (IEC CIM) to facilitate data sharing with external entities (e.g., DPU, DER aggregators, customers) are necessary to support evolving customer expectations including animating new distribution markets and engaging DER owners in the future.[22] Coordinated with business process changes, the proposed investment is focused on starting that journey

[22] Appropriate security and privacy measures will be followed to ensure Critical Energy Infrastructure Information (CEII) and Personal Identifiable Information (PII) data is not shared.

- deploying a data catalog, data modelling, and creating data quality toolsets to enable grid facing and asset management use cases. These capabilities will bring data consistency, data availability, and reduction of redundant or conflicting data.

Growing demand for raw operational data from SCADA by planning engineers and analysts negatively impacts the performance of the existing PI Historian database and servers that are critical for Distribution Control Center operations. In addition, NERC CIP restrictions on Critical Network Infrastructure (CNI)[23] access make PI Historian difficult to access from the Company's corporate network. The PI servers within the CNI environments are designed to support Distribution Control Center operations and not the bulk extracts being requested by users from the corporate network. To overcome these challenges, the Corporate PI Historian initiative included in Data Management will enable a dedicated instance of PI, that loads both T&D operational data to support planning uses and analysis requirements.

Current State: Legacy Project Driven Integration (Data sourcing is non centralized)



[23] CNI refers to tools and systems that are used to manage and control critical infrastructure.

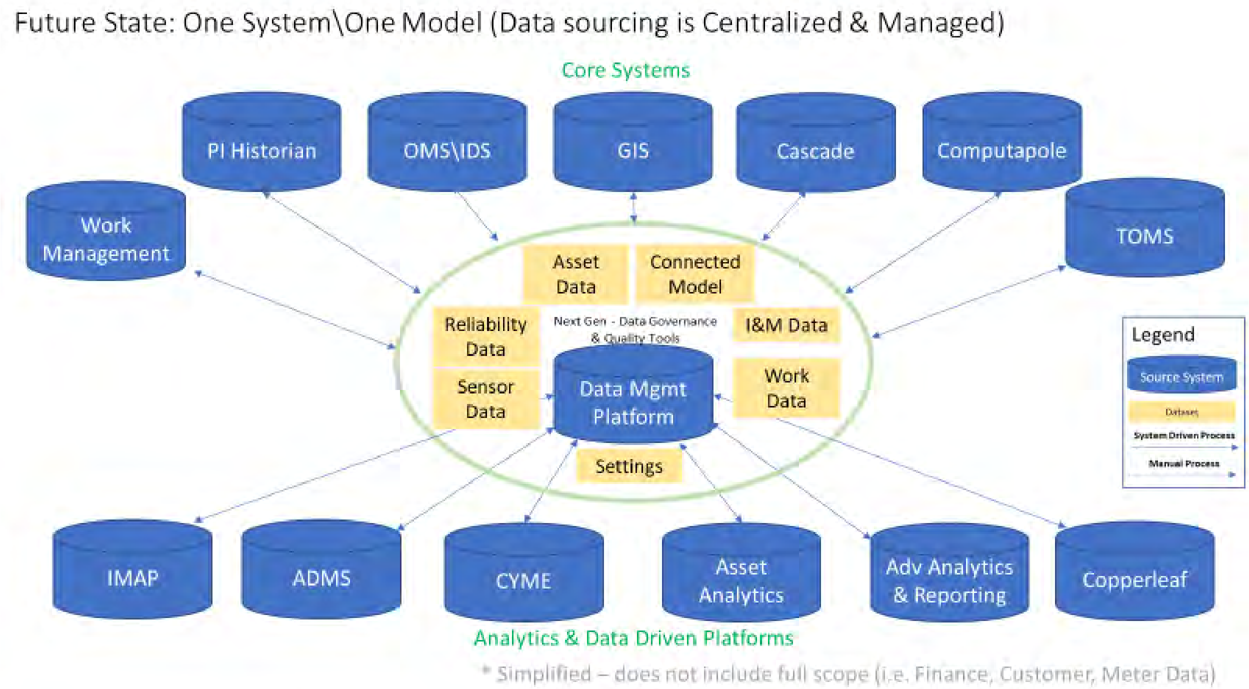


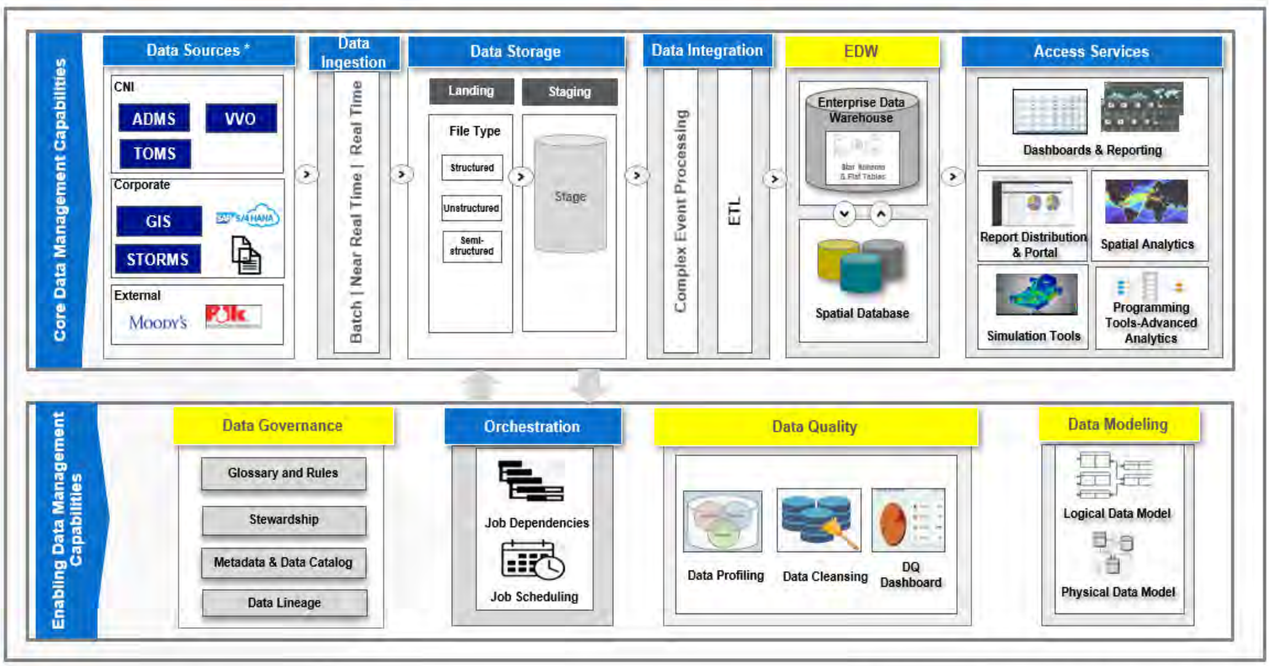
Figure 15: Current and Future State Data Platform

<u>Goals and Objectives</u>

Enterprise Analytics (EA) is delivered upon a foundation of sequential Data Management initiatives. These investments in Data Management ensure access to timely, accurate information, and will enable the Company to respond to outages and potential grid load constraints, resolving problems more quickly and preventing future problems.

This investment will build foundational data management capabilities by enabling the necessary data management tools and processes to ingest data, catalog data, assess and improve data quality, and enhance data governance across key datasets, as illustrated in Figure 16. The platform will also provide data management tools to store and manage various system of records data and build predictive analytics to improve business efficiencies and energy saving measures.

In line with the Company's Business Management System (BMS) standards, this centralized platform will be used to measure/monitor critical data elements and their accuracy, integrity, completeness, and consistency to support continuous data improvement. Setting this foundation is critical to establishing the longer-term vision of a data management platform, which will be necessary in the future as the amount of data collected and need for data continues to grow.



* Not a complete list. Only a few sample data sources shown above.

Figure 16: Grid Modernization Data Management Architecture

Increased DG interconnection applications and grid constraints are examples of new processes that require leveraging RTU information for Capacity Hosting assessment, Load Curves outside of the control room environments. These increased demands impact operational performance and a replicated reporting environment that can be accessed by the various engineering, asset management and advanced analytics teams is required.

The Corporate PI Historian investment, included in Data Management will permit engineering, asset management, and advanced analytics teams secure access to network parameter time series data without affecting performance of the operational systems. This project will implement a replicated reporting environment that can be queried on demand without impacting the performance of the CNI instance while honoring NERC CIP restrictions. The dedicated environment will be used to support internal modelling, analysis, and reporting needs. In addition, this project will allow the Company to consolidate data currently stored in separate systems and data stores, reducing complexity, and enabling further analytical insights. Data will be migrated from two additional datasets/systems. These are:

- Feedpro – a system used to record and store device readings that are not RTU enabled and are collected manually

- Network Device Settings – Many assets on the Company's network have specific settings required for proper operation. This project will consolidate information from several data sources allowing greater levels of data governance and ensuring availability of this data to downstream systems and processes.

Deployment Schedule

Grid Modernization Data Management Phase 1 includes creating a comprehensive Data Model and setting up the tools and technologies for Data Quality and Data Cataloging capabilities. The project has already completed an assessment of Business Data Capabilities, High Level Use Cases, and a Preliminary Data Source Inventory. Following this, the project has detailed the scope and plan to address Data Catalog and Data Quality requirements for grid modernization. Initial assumptions about the product and architecture for the Enterprise Data Platform were re-validated and the project has now finalized the software products for this project covering: Data Catalog, Data Quality, Data Store, and Visualization/Reporting.

Grid Modernization Data Management Phase 2, will build on the foundation created by Phase 1 to further enhance our capabilities. This will include integrating additional datasets, master data management and deploying Snowflake to act as a central data repository for storing, sharing, and integrating data with upstream and downstream processes to ensure data consistency. This will enable the necessary data analytics, visualization and data driven decision making capabilities to advance the company's grid modernization objectives.

A key objective the Company has identified is maturing our Asset Management capabilities to optimize investments in our networks. This has been acknowledged at the board level through approval of the Company's Asset Management BMS standard. Customers and regulators expect and deserve excellent reliability while creating flexible networks that enable increasing DER penetration. There are increasing reliability performance targets with a focus on driving costs down. In order to meet these challenges, we need to enable our asset management function with modern tools and integrated data to find opportunities.

Data driven decision making is critical to meeting this objective. Implementation of visualization tools, data analytics and further integration of datasets that live across different system domains will help provide the insight we need. In addition, we need to make sure we leverage insights and benchmarking from both peers and other asset intensive industries to drive us toward our best-in-class aspiration.

Currently, Asset Management areas of Asset Inspection and Maintenance are based on cyclic inspections, for example 5-year cycles. By being more data driven, the company will be able to take a risk-based approach to inspection and maintenance. Thereby being able to direct maintenance dollars to areas where it will be of the most benefit to our customers both in the near term and in the long term. High impact risks can be identified earlier and maintenance actions to mitigate them can be conducted without having to wait for the 5-year cycle.

This project is one part of a suite of complementary technologies under our "One System, One Model" strategy, which focuses on meeting our changing data requirements. The Company has identified the need to evolve from semi-integrated data to a centralized, integrated data platform to ensure data consistency, quality, availability, and reduction of redundant or conflicting data for use in our operations, planning and other business processes and systems. This also supports wider data sharing with external stakeholders which will be necessary to meet business goals and DSO requirements. Key needs that are enabled by this project are:

- Processes and tools to manage two-way power flows and high levels of DER require a corresponding capability to manage related data and how it is shared between processes and toolsets.
- Proposed ADMS phases, enhanced distribution planning tools and transparency of data through methods like the DER System Data Portal require that our data is consistent, of the right granularity and quality and available at the right time to deliver their full benefits.
- In the future, we will be required to not just share data amongst our own process and systems but make it available in common information formats for other grid stakeholders. We must have a robust data management platform to complement governance, process and skillset changed to meet the vision.

The project will setup required infrastructure including hardware and software to install and configure the Corporate PI Historian system. The environment will include production, disaster recovery, development, and testing. The scope of work also includes sourcing data from both Transmission PI and Distribution PI systems to have a centralized SCADA data repository for corporate users, which includes extracting data from non-RTU based systems, like Feedpro, to have a single unified PI Historian to store and manage data from both RTU and non-RTU data feeds.

In keeping with the overall principles for Data Management, the Corporate PI Historian will export specific data sets to the central data repository on SnowFlake, where it will be available to a wider set of users for more advanced data requirements.

The following chart provides an overview of the deployment schedule:

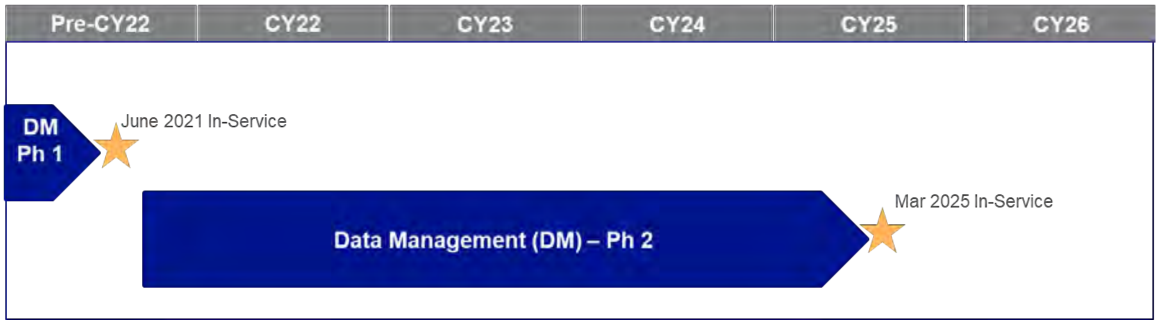


Figure 17: Data Management Deployment Schedule

Incremental

Data Management (including Corporate PI Historian) investments enable data driven operational decisions and maximize the value that can be derived from key grid modernization investments, including Advanced Field Devices, GIS, ADMS, Operational Telecommunications, and Modular Optimizing Applications like VVO/CVR. These efforts are foundational to enable the desired granular management of the grid envisioned in this GMP. Data Management (including Corporate PI Historian) investments maximize the value that can be derived from key grid modernization investments, including Advanced Field Devices, GIS, ADMS, Operational Telecommunications, and Modular Optimizing Applications like VVO/CVR. These efforts are foundational to enable the desired granular management of the grid envisioned in this GMP.

Benefits

A solid data management foundation with frequent data enrichment will deliver better quality data for analysis and decision-making. This includes data from GIS, ADMS, PI historians, DERMS, AMI, and field-edge devices and sensors. In the long-term, Data Management aims to achieve the following:

- Enhance operations and engineering decisions via network visibility of increasingly granular field-edge data points
- Support risk-based asset management decision making through improved data accuracy, confidence, and analysis[24]
- Support better predictive analytics and forecasting models for outage management, load flows, load forecasting and emerging distribution network functions
- Provide a central data platform for storage, integration, and access to distribution network and asset data

[24] Risk-based asset management takes into account the likelihoods and consequence of the failure of an asset.

Budget

Table 12 presents the 4-year budget for the Data Management/Enterprise Analytics. The Company estimates investing $5.85 million through CY 2025.

Table 12: Data Management/Enterprise Analytics – 4-Year Plan Budget

Data Management/ Enterprise Analytics	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$1.89	$1.33	$1.21	$0.31	**$4.73**
OPEX ($M)	$0.30	$0.32	$0.32	$0.18	**$1.12**
Total ($M)	**$2.19**	**$1.64**	**$1.53**	**$0.50**	**$5.85**

3.2.5.3 Cyber Services

Background

Cyber security is critical to managing the distribution system more granularly in order to reliably, safely, and cost-effectively meet customers' evolving expectations and provide them with greater choice and control in addressing their energy needs, and to protect the distribution system as increasing numbers of grid modernization devices are added to the system. Cyber and privacy threats may emerge as new, grid connected technologies are introduced. Monitoring and control capabilities must include cyber security solutions in the process rather than as a retrofit or after-thought. The following potential risks highlight why cyber security is necessary for developing a modernized and more granular distribution system:

- Greater complexity increases exposure to potential attackers and unintentional errors
- Networks that link more frequently to other networks introduce common vulnerabilities that may span multiple systems and increase the potential for cascading failures
- More interconnections present increased opportunities for "denial of service" attacks, introduction of malicious code (in software/firmware) or compromised hardware, and related types of attacks and intrusions
- As the number of network nodes increases, the number of entry points and paths that potential adversaries might exploit also increases
- Increased data gathering and shift towards two-way information flow increases the potential compromise of data integrity and confidentiality of data, resulting in potential data breaches, customer privacy intrusions or system compromise

Goals and Objectives

Proposed cyber security efforts will align with and leverage National Grid security services incorporating potential improvement opportunities and expected evolution of technologies and threats. Specific cyber security efforts will include:

- Expand integration between Corporate, CNI, and OT security architecture and operating model evolution in order to reduce security risk by increasing visibility, reducing complexity, and enabling the increased usage of existing capabilities
- Increase incorporation of formalized security practices and rules of engagement across project lifecycle activities, such as vendor acquisition and solution delivery, in order to support sustained security performance as business and technical operations evolve
- Assess cyber security risks associated with the introduction of new grid modernization capabilities, identifying and prioritizing risks based on potential impact and the likelihood of cyber security threats materializing
- Evaluate and implement, based on risk, key foundational improvements, such as baseline configuration management, logical access controls, and data governance, to better build consistent security coverage, services, and processes across all business and technology functions

To further understand the cyber security improvements required, strategic risk analysis is undertaken to understand how cyber security threats may manifest in grid modernization applications and systems, and an impact analysis is completed to understand the potential impact and likelihood of a risk materializing. Based on the outputs of this analysis, improvement areas are identified and a plan of action is laid out to address cyber security threats in a coordinated and prioritized manner.

All systems, components, and integrations are considered in the following service domains described below: Network; Data Protection; Identity and Access Management; Vulnerability; Security Orchestration, Automation and Response ("SOAR"); Platform, Third Party Risk, and Training and Awareness. While these service domains currently feature foundational capabilities in place to support the current state of National Grid's operations and are improved on an on-going basis, further enhancement is required to ensure that the risk associated with grid modernization is mitigated through the deployment of security controls to address cyber security risk associated with the future state of grid operations.

Network

The Network service domain covers the protection of National Grid's CNI (e.g., core switches, routers, proxy gateways) against cyber-attacks—this includes limiting vulnerabilities in the network infrastructure and preventing unauthorized access, misuse, modification or denial of a network resource or the network itself. Network security relies on layers of protection and consists of multiple capabilities including network monitoring and security software in addition to hardware and appliances.

Network initiatives include the deployment of hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Advanced log management adding event-reduction, alerting and real-time analysis functionality
- Agentless technology to interrogate network infrastructure, detect suspicious devices, programmatically limit access, and remediate at-risk endpoints
- Network taps that copy packets for monitoring and provide intelligent management capabilities that monitor link and power states of diverse connected devices
- Scan-less vulnerability assessment using intelligence repositories and advanced analytics to detect exposures on traditionally “un-scannable” distribution system devices and zones

Through the enablement of the capabilities across the Network area, grid modernization applications will benefit from network monitoring and alerting at the Cyber Security Operations Center and enhanced perimeter defenses that address cyber security related risk and improve operational efficiency.

Data Protection

The Data Protection domain provides the protection of data from accidental or intentional but unauthorized modification, destruction or disclosure using data protection solutions and other safeguards to ensure that confidentiality and integrity is maintained. Data Protection enables the proactive and appropriate management and protection of corporate data (in-motion and at-rest) on the Corporate Data Network based in accordance with business requirements.

Data Protection initiatives include the deployment of hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Network and user activity monitoring, secure roaming users and mobile devices security, and global services management from a single management console
- Scalable agent-based data loss prevention using a hybrid premise/cloud-based solution to proactively tag/classify data
- Data discovery and automated classification labeling and asset tracking

Data Protection investments will reduce the risk associated with data theft, data loss or data integrity violations. Grid modernization transforms the way National Grid operates the grid, and this is completed through leveraging vast amounts of previously untapped data. Data Protection investments seek to ensure that data is safe and secure throughout its lifecycle.

Identity and Access Management

The Identity and Access Management (“IAM”) domain provides the management of individual identities, and their authentication, authorization, and privileges/permissions within or across system and enterprise boundaries, with the goal of increasing security and productivity while decreasing cost, downtime and repetitive tasks. IAM's goal is to ensure that only authorized people can access resources in the enterprise.

IAM initiatives will deploy hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Least-privilege access enforcement, and privileged activity monitoring/analysis complemented by policy-based outbound real-time alerts
- Privileged identity management capability for both physical and virtual environments by control oversight of privileged user access
- Policy-based authentication and single sign-on for web-based applications
- Critical files and registry keys protection from tampering, enforces policies, and reports on violation sources
- Remote access

IAM will ensure a centralized approach to access throughout all grid modernization applications, ensuring that the correct levels of access are granted at the origin of identities and ensuring that those with elevated access are governed appropriately. Moreover, as identity theft is a leading cyber security threat across all organizations, IAM will establish baseline behavioral information, enabling the alerting of anomalous individual behaviors that may be the result of identity theft.

Vulnerability

The Vulnerability domain provides proactive threat management and reactive response capabilities. This service will analyze logs and monitor applications and systems for abuse/misuse, provide intelligence around cyber-threats, scan both internal and external systems for vulnerabilities and compliance, analyze and support security patching, and provide around-the-clock (i.e., “24x7”) response capability.

The Vulnerability domain will:

- Optimize vulnerability scanning capabilities
- Establish a centralized asset lifecycle management
- Implement code scanning and centralized views of threat intelligence feeds and reporting

Vulnerabilities are inherent to all systems, applications and code. Grid modernization will introduce new applications to our environments that require real-time patch management, vulnerability scanning and a prioritized approach to vulnerability remediation.

Security Orchestration, Automation and Response ("SOAR")

The SOAR domain provides a vital line of defense against unauthorized, malicious activity in real time. This requires employing the right people, technology and processes. The Company's Security Operations Center, a team of well-equipped security analysts, is organized to prevent and report on cyber security risks, but even more importantly to detect, analyze and respond to incidents. It is a vital node in charge of the Company's issues related to cyber security.

The SOAR domain will:

- Deploy hardware, software and the associated maintenance, services, and labor to enable logging and correlation of data and applications for real-time analytics
- Incorporate behavioral analysis to spot applications and protocols regardless of whether they are plain text or use advanced encryption and obfuscation techniques
- Enhance playbooks based on expanded visibility and conduct training on alert types

SOAR will provide the centralized capability for monitoring and event logging across all grid modernization systems, networks and applications, allowing for data collecting and log gathering, centralized into one platform. The SOAR platform will reduce risk across not only grid modernization investments, but throughout the organization as a more holistic view of security event data is consolidated and alerting is automated, reducing the reliance on manual intervention for event flagging.

Platform

The Platform domain provides protection of workstations, laptops, smartphones and tablets by enabling device encryption, secure configuration, and continuously protected operation. This service extends the monitoring and controlling of hosts and endpoints to meet the required standards. The service will monitor the state of endpoints (e.g., host assets like servers, laptops, desktops, smart devices) for threat indicators; investigate events to determine severity, accuracy, current capabilities, and future enhancements; and ensure critical events can be escalated to ensure effective management of security vulnerabilities.

The Platform domain will implement hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- File integrity and configuration monitoring
- Application whitelisting
- Baseline configuration standards definition and maintenance
- Cloud security skillsets and operating practices expansion

Grid modernization applications will benefit from the improved visibility and monitoring which aim to reduce the impact and duration of cyber events by alerting the presence of malicious content and preventing further infection onto interconnected systems.

Third-Party Risk

The Third-Party Risk domain provides software, hardware, and procedural methods to protect applications from external threats. This domain embeds within the software development process to protect the various applications that might be vulnerable to a wide variety of threats. Security measures built into applications and a sound application security routine minimize the likelihood that unauthorized code will be able to manipulate applications to access, steal, modify, or delete sensitive data.

The Third-Party Risk domain will ensure that:

- Policies or procedures are periodically reviewed, assessed, and updated, as necessary
- Third parties appoint positions and/or personnel to ensure security and privacy policies are properly maintained, updated, and followed
- Privacy practices are transparent

Third-party risks introduced by way of grid modernization will be addressed by ensuring that a coordinated approach is defined, specifically tailored to grid modernization, and leveraging processes already established to manage third-party risk at National Grid. Grid modernization will introduce a variety of third parties who will leverage National Grid data, information, infrastructure and services. Ensuring that these third parties do not increase the level of security risk when interacting with National Grid is critical.

Training and Awareness

The Training and Awareness domain is responsible for reducing the risk of a human error resulting in security breach by ensuring that customers, employees, contractors and third-party users are aware of information security policies, threats and concerns as well as their responsibilities and liabilities. The Security Awareness Program inculcates appropriate knowledge and attitudes regarding cyber security accountability and responsibility among all members of the business – including protection of the physical, but especially critical cyber assets (i.e., applications, application hosts, and the information that resides on and is communicated between systems).

There are several key objectives for the Training and Awareness domain, including:

- Obtaining and disseminating the latest cyber security news and trends from internal monitoring and external sources
- Establishing training plans and schedules for continuing cyber security education

- Developing, advocating, implementing and evaluating internal cyber security training programs that are needed to establish and maintain a continuously optimizing cyber security program
- Ensuring that the business is kept up to date with emerging security threats, vulnerabilities, attack methodologies, etc.
- Providing awareness of threats and risks to vital business processes
- Developing a "Culture of Security"
- Defining and supporting cyber security awareness program improvements

Grid modernization will require specific cyber security training and awareness campaigns targeting overarching awareness and training as well as role-specific training to ensure individual responsibilities are known and understood.

By integrating these functionalities in the existing networks, systems, and touch-points that are capable of exchanging information seamlessly, the older proprietary and often manual methods of securing utility services will give way to more open, automated and networked solutions. The benefits of this increased connectivity will depend upon robust security services and implementations that are necessary to minimize disruption of vital services and provide increased reliability, manageability, and survivability of the electric grid and customer services. Recognizing the unique challenges of grid modernization is imperative for deploying a secure and reliable solution.

Benefits

Cyber security provides protection of cyber assets necessary for grid modernization (e.g., computer hardware and software, information) from theft, damage, disruption or misdirection of the services they provide. This functionality is a foundational element and supports all other key functionalities.

The importance of cyber security is increasing as more intelligent devices are interconnected and volumes of data increase along with an ever-growing cyber-attack surface. The need to maintain confidentiality, ensure data integrity, and improve resiliency is increasingly important as the Company leverages this information to drive more efficient operations and improve decision making.

Incorporating cyber security and privacy provisions into all grid modernization investments and activities will ensure the reliability of the electric distribution grid, with information integrity built in and the confidentiality of customer information maintained within various business processes addressing privacy concerns. The cyber security provisions built into grid modernization will provide for:

- Availability: avoid denial of service
- Integrity: avoid unauthorized modification
- Confidentiality: avoid disclosure
- Authenticity: avoid spoofing/forgery
- Access control: avoid unauthorized usage

- Auditability: avoid hiding
- Accountability: avoid denial of responsibility
- Third-party protection: avoid attacks on others
- Segmentation: limit the scope of attacks on the solution
- Quality of service: Maintain reasonable latency and throughput
- Privacy: Maintain customer data in a fashion that keeps confidential customer data confidential

Deployment Schedule

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

Status

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

Major Tasks

The approach leverages security capabilities inherent in grid modernization solutions as well as existing information security controls for protecting vital systems and operations. The cyber security implementation plan addresses, but is not limited to, the following concerns:

- Specifying security requirements as part of the selection criteria for grid modernization equipment, systems, and third-party service providers
- Monitoring and controlling access to all grid modernization equipment and systems
- Implementing appropriate cryptographic and other electronic security measures to strengthen the confidentiality and integrity of sensitive information during use, transmission, and storage
- Implementing appropriate redundancy and other features in grid modernization solution design to protect and enhance availability
- Employing secure or “hardened” configurations of hardware and software capabilities
- Employing strict access control and authentication methods to prevent unauthorized access to user and system accounts, web services and other system resources
- Providing appropriate malware protection for systems and relevant resources

- Maintaining ongoing processes to ensure security-related updates are identified, tested and implemented
- Providing continuous security monitoring for system intrusions and other unauthorized access
- Monitoring and tracking security events appropriately and integrating these events into a broader incident response and reporting process
- Ensuring compliance with existing enterprise cyber security standards
- Deploying solutions with the flexibility to upgrade and maintain compatibility with evolving government and industry security standards
- Requiring third-party smart grid vendors to maintain a proactive security process by utilizing a secure development lifecycle, conducting security testing on their solutions, and other appropriate activities
- Assessing the security posture of grid modernization systems, both periodically and event-driven (e.g., application, firmware, and hardware updates) via independent third-party cyber security testing
- Developing and implementing remediation plans for identified risks and emergent system vulnerabilities

The Company currently has a cyber security program, infrastructure, applications, systems, staff and operations. The GMP's cyber security implementation plan seeks to enhance existing capabilities where applicable and invest in new capabilities where no existing capability is fit for purpose.

<u>Budget</u>

Table 13 presents the 4-year budget for Cyber Services. The Company estimates investing $2.35 million through CY 2025.

Table 13: Cyber Services – 4-Year Plan Budget

Cyber Services	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Total**
	CY 2022	**CY 2023**	**CY 2024**	**CY 2025**	**CY22-25**
CAPEX ($M)	$0.62	$0.32	$0.33	$0.34	**$1.61**
OPEX ($M)	$0.08	$0.22	$0.23	$0.21	**$0.75**
Total ($M)	**$0.71**	**$0.54**	**$0.56**	**$0.55**	**$2.35**

3.2.5.4 Communications and Networking

Background

A secure and robust communications network is a foundational element to the GMP. The Company currently utilizes several different communications technologies for the collection of customer meter and T&D system data. The existing communication networks include private fiber and microwave, along with commercial telecommunication carrier wireline and wireless services. While the existing communications network has supported legacy grid data requirements, it must be upgraded and expanded to support future grid modernization and enable greater reliability, control, monitoring, and security of the assets.

Currently, the Company's communications network supports corporate enterprise functions, substation RTU/SCADA, grid edge devices, off-site data center connectivity, and Company facility interconnections. A combination of wireless solutions and wireline connectivity such as fiber optic or copper wire cables make up the current communications network. Wireline communications are predominantly used between the substations and wireless communications is most often deployed at the network edge along a feeder or at a utility pole. The majority of the current communications network is owned and managed by commercial carriers where the wireless component is based on a public cellular network. As with many contracted services, there can be restrictions on appropriate use that can present challenges to operating the grid in the desired capacity to enable ultimate benefit to customers. For example, third party Internet of Things (IoT) usage policies for standard commercial cellular services often prohibit utilities from performing static device interrogation at intervals more frequent than 15 minutes; this presents challenges as we envision a dynamic, interactive, clean energy marketplace. In addition, these telecommunication carriers are now in the planning stages of eliminating leased communication via analog means and replacing them with digital technologies. This requires a replacement of the Company's telecommunications terminal equipment to be compatible with the new digital service as well as replacing the copper lines with potentially fiber optic cables where it is cost effective to do so.

In addition to these foundational telecommunications needs, distribution grid assets (e.g., FM, advanced capacitors & voltage regulators to support VVO, Advanced Reclosers & Breakers to support FLISRADA) and the significant proliferation of DER facilities are increasing the Company's communications network needs substantially. These assets and facilities currently utilize public cellular networks and a cellular gateway to bring the data back to the Distribution Control Center. In the future the Company is responsible for the upfront and ongoing operations and maintenance (O&M) costs for communications with large DG facilities, including monthly public cellular network fees and the initial investments in the cellular gateway. In several cases, commercial cellular services IoT usage policy limitations preclude this technology from being leveraged due to compliance requirements (NE ISO OP-18, etc.).

While telemetry is typically provided at larger DG facilities where an RTU or a PCC recloser with integrated relay is required, DG projects below 500 kW are not required to install these devices and, subsequently, very few small DG facilities (<50 kW) have communications at this time. Note that PCC reclosers, when available, only enable on/off "control" of the site by dispatch when absolutely necessary and are not used for balancing the distribution system or for operational efficiency.

Large DG facilities require communications under the following conditions:

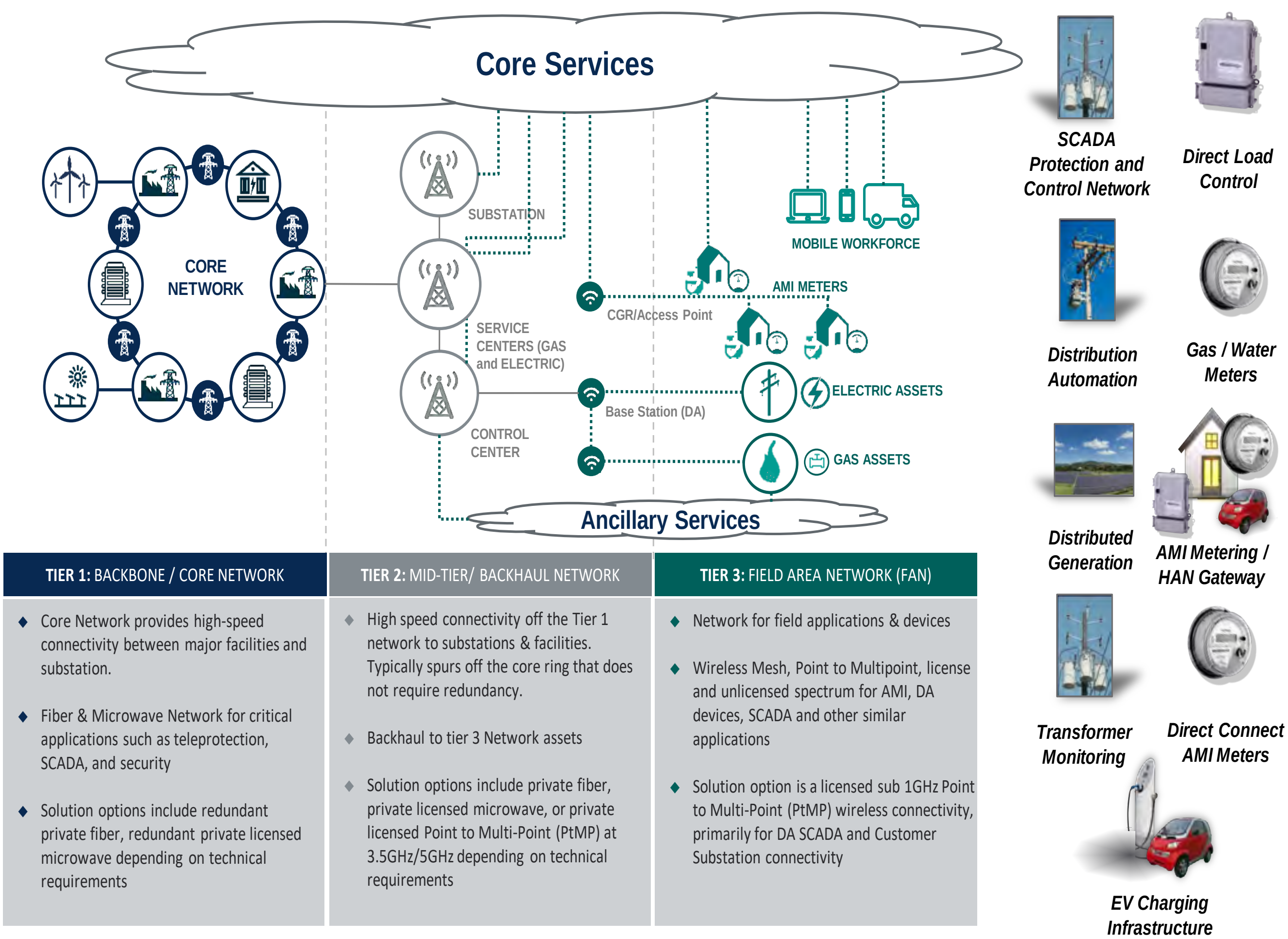
- 500 kW or larger facilities connected to 5 kV or lower distribution circuits
- 1,000 kW or larger facilities connect to higher than 5 kV but lower than or equal to 15 kV distribution circuits
- 1,800 kW or larger facilities connected to higher than 15 kV sub-transmission circuits

As of June 25, 2021, the Company had 1,978 public cellular devices associated with distribution grid assets. Note that while it is necessary for the Company to monitor Independent Power Producer ("IPP") projects, including "utility-scale" solar PV and wind projects that are typically connected through the transmission system and participate in the ISO-NE markets, the Company is not responsible for managing or controlling these large scale IPP projects.[25]

The Company recently set out to understand how the Company's communications network and governance should evolve to cost-effectively meet the changing needs of customers and the protection, control, and monitoring of the Company's electric assets through 2030. The Company investigations reveal that opportunities exist to enhance control, performance and cost-effectiveness of the communications network through the development of a secure, private communications network to accommodate the Company's electric T&D systems.

Communications networks are organized by network "tiers" as shown in Figure 18, where Tier 1 and 2 is known as the Transport Network and Tier 3 as the Field Area Network (FAN). This figure also provides a depiction on the right of the various technologies and services that are supported by the network across each tier.

[25] These projects do not require an RTU, but pole top reclosers capture the Company needs for site monitoring and control. Pole top reclosers only enable on/off "control" of the site by dispatch when absolutely necessary, and are not used for balancing the distribution system or for operational efficiency.



TIER 1: BACKBONE / CORE NETWORK	TIER 2: MID-TIER/ BACKHAUL NETWORK	TIER 3: FIELD AREA NETWORK (FAN)
◆ Core Network provides high-speed connectivity between major facilities and substation. ◆ Fiber & Microwave Network for critical applications such as teleprotection, SCADA, and security ◆ Solution options include redundant private fiber, redundant private licensed microwave depending on technical requirements	◆ High speed connectivity off the Tier 1 network to substations & facilities. Typically spurs off the core ring that does not require redundancy. ◆ Backhaul to tier 3 Network assets ◆ Solution options include private fiber, private licensed microwave, or private licensed Point to Multi-Point (PtMP) at 3.5GHz/5GHz depending on technical requirements	◆ Network for field applications & devices ◆ Wireless Mesh, Point to Multipoint, license and unlicensed spectrum for AMI, DA devices, SCADA and other similar applications ◆ Solution option is a licensed sub 1GHz Point to Multi-Point (PtMP) wireless connectivity, primarily for DA SCADA and Customer Substation connectivity

Figure 18: Telecommunications Tier Definitions

Tier 1 is the core network backbone consisting of leased circuits, private fiber, and private licensed microwave from which all data from Tier 2 and Tier 3 assets will traverse through into back-office systems. Tier 2 is the mid-tier backhaul network of leased circuits, cellular, private fiber, private licensed microwave, and/or private licensed Point-to-Multipoint (PtMP) communication. Tier 3 refers to a field area network (FAN), which extends connectivity into the realm of the distribution system, as well as remote transmission assets, so that advanced grid devices and DER can be integrated with grid operations. The primary access of the FAN is wireless using a combination of commercial cellular and privately licensed spectrum, which offers the highest level of control, reliability, and security. The FAN supports the Company's plans to integrate remote sensors, advanced capacitor controls, line voltage regulators, state-of-the-art reclosers and circuit breakers, as well as connected DER devices with the Distribution Control Center ADMS.

Goals and Objectives

Communication between devices in the field and Company systems is essential to the overall success of the GMP. The design of the network is driven by the communications requirements from all parts of the GMP. The main drivers for the telecommunications ("telecom") network plan are:

- Provide a reliable, cost-effective two-way communications capability to end devices including grid automation controls, field sensors and substations.
- Ensure the network meets all technical requirements for the devices and systems deployed. These requirements include availability, latency, bandwidth, security and other performance considerations.
- Provide to the operations groups the capability to plan, design, manage, maintain and troubleshoot the communications network.
- Enable new grid technologies as they become available and future-proof the network as much as practical.

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

A significant portion of the communications network costs are the costs to build and operate a private network, which will provide the majority of communications for the grid modernization investments and new distribution devices, including those supporting customer DERs. Aside from the added benefits of greater network control and reliability in transitioning from a public carrier solution to a private one, a key driver of this change is to reduce long-term costs (e.g., commercial cellular RTB costs) that increase with every new grid device added. Given all the grid modernization initiatives, plus increasing adoption of DG and future EV adoption, the Company anticipates exponential growth in the number of endpoint nodes that will need connectivity.

The large increase in connected devices anticipated in the future would result in significant commercial cellular RTB costs if investments are not made in communications network strategy. With significant cost coming from increasing cellular connectivity, the justification of investing in a private network becomes stronger. Further expanding communications to the network edge, the Company is also considering using the same private network to deploy future technologies for AMI communications, which would be standards-based and more reliable than traditional systems.

As the number of network end nodes increases exponentially, the economic reasoning for deploying a private network over commercial cellular becomes evident and well-founded. Many utilities across the country have already begun the network transition from public to private. The Company is in contact with many of these utilities and has been engaged in technical exchanges. Many of the existing private network deployments utilize the same 700MHz (A Block) spectrum that the Company is considering for Massachusetts. This band is at the forefront due to an attractive value proposition especially given its low frequency and associated strong propagation,[26] which minimizes radio site count. A total of 19 utilities have purchased this spectrum for their service areas, some of which include: First Energy (OH), Salt River Project (AZ), Great River Energy (MN), Puget Sound Energy (WA), and CenterPoint Energy (TX).

The Company is in the early stages of planning and implementing the various recommendations from the communications network strategy of expanding private wireline and wireless networks. In the interim (i.e., FY 2022-2024), while the Company develops and deploys the investments, the Company intends to leverage its existing networks and scale its cellular gateway as necessary to accommodate the increasing number of devices on the distribution system. During this period, the Company will continue to leverage secure public network options, including the upfront investments in cellular gateway capacity to bring the data back to the Distribution Control Center. As the private network is being rolled out, these existing cellular radios may be used as failover on some of the more critical control nodes further increasing network availability.

Tier 1 & Tier 2 (Network Transport)

The starting point of upgrading the communications network to support grid modernization lies within Tier 1 and 2. This core network piece acts as the foundation upon which other communications network initiatives may be added such as Tier 3 wireless access for field devices at the network edge. Obsolescent networking gear needs to be upgraded with the most current technology in order to provide increased network reliability, control, security, and performance. It's also the easiest and most economical way to begin privatization by way of owning the business-critical networking equipment on premise at substations and key facilities. In addition to using private fiber and microwave to connect these strategic network nodes, telecom service providers may also provide the physical fiber between endpoints. However, the Company will always be able to manage and control this important backbone of the communications network by owning the active electronics. With private ownership of network equipment, a more competitive, vendor-neutral environment exists to partner with the best service providers at the lowest overall cost. Over time, more private fiber will also be deployed, truly reducing reliance on public carriers and overall costing of network backhaul.

Modernizing Core Network Equipment - Data Multiplexer (DMX)

The primary equipment at the heart of network transport is called a data multiplexer (DMX). Currently, the existing DMX solution provided by Nokia has reached end-of-life, and the standard technical support

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[26] Propagation refers to the transmission of radio waves or signals through space, commonly referred to as network coverage.

will be discontinued at the end of 2021. In preparation for this event, the Company has recently completed the evaluation and assessment of the replacement technology and has chosen the final equipment vendor. The leading technology is Multi-Protocol Label Switching (MPLS) which is protocol-independent and highly scalable, allowing for any type of transport medium, using any network protocol. True network convergence capable of combining many older legacy technologies may be achieved with MPLS.

The network design for Massachusetts has also begun where 59 key nodes have been identified to make up the core network. The Massachusetts network represents a subset of the greater 150 DMX sites located throughout the Company's US service area. The next steps will be to examine the benefit-cost of leasing from commercial carriers, installing private fiber, or adding microwave links. While the majority of the network backbone resides at the transmission substations, it is important to note that all proposed grid modernization communications network initiatives involving distribution substations and Tier 3 advanced field control devices greatly depend and interconnect with this core network.

Technical Obsolescence of Leased Analog Circuits

One of the biggest drivers of upgrading the telecom network with new network gear and fiber connectivity is the commercial carriers' imminent plan of eliminating Digital Signal 0 (DS0)[27] and analog leased lines to substations and replacing them with Transmission System 1 (T1)[28] or other digital technologies that may not be the most future-proof or appropriate for the proposed grid modernization initiatives. By proactively responding to this unavoidable directive brought on by the carriers, the Company will take the lead in network redesign and leverage on-going efforts, wherever possible, to cost effectively expand the reach of fiber optics. In order to enable the GMP initiatives proposed, the existing rudimentary analog communications must first be upgraded to current technologies that support the new requirements for increased network performance, security, reliability, and control.

Eliminating the heavy reliance of commercial telecommunications carriers antiquated analog technology is a major priority in updating the 431 substations across the Commonwealth. Throughout the United States, commercial carriers are currently retiring analog circuits and shifting to newer technologies such as fiber optic cable, which is either significantly more expensive or just not viable as the cost of deploying fiber especially in rural areas is cost-prohibitive. Therefore, as carriers terminate service, some of the rural site locations with existing analog will have nontraditional solutions such as wireless or satellite depending on the application requiring connectivity.

Tier 3 (FAN)

An appropriate wireless radio and antenna is required at each control device (e.g., reclosers, capacitor control, voltage regulators, remote sensors, etc.), which allows communications back to the core network. The cost for these radios and their commissioning are accounted for in the budget for the

[27] DS0 is a basic digital signaling rate of 64 kbits per second.
[28] T1 is a basic digital signaling rate of 1.54 Mbits per second.

Advanced Field Devices included in the GMP and not in the telecommunications line items. However, investments included in this telecommunications section include any backhaul and receiver equipment costs as well as the cost of any on-going cellular data plans. Aside from the new cellular interconnections used to provide communications in the near term, the Company is evaluating a private FAN as a replacement to the existing cellular platform. The target Tier 3 solution will provide near ubiquitous FAN coverage throughout the Company's Massachusetts service territory allowing for an expansion of the network into the field (or "edge"), which will enable multiple grid modernization efforts through a communications path to the Company's back-office systems.

Network Asset Management Application

In addition to the needs to deploy the necessary communications network strategy, the Company must also enhance its ability to plan and manage this growing class of controllable assets. As part of the Network Management investment, the Company is reviewing its current methods, which lack features for graphical and logical circuit planning, design and evaluation. Adding new tools and developing interfaces to current systems will improve maintenance and operations. Existing manual practices cannot keep pace with the increasing volume and flexibility required for grid modernization. Therefore, the Company is progressing plans to implement a TOMS (Telecom Operations Management System) tool for the planning, engineering, commissioning, management and operations of the Company's communications network systems that integrates with GIS, Work Management (WM), asset management system, and a future planned Integrated Network Operations Center (INOC).

With the need to manage the distribution system more granularly over the next ten years, TOMS will enable provisioning and management of the communications infrastructure to support this transformation and will replace the manual methods currently in place. The project will select, purchase, install and integrate the software with the ability to capture all pertinent data for telecommunications equipment and circuits utilizing both manual and automated data entry with mobile technology. TOMS will provide a single telecommunications repository tool that will facilitate the planning, engineering, operating and maintaining of existing telecom assets as well as the future private electric telecommunication network. The tool will also streamline communications projects, improving the time to deploy and reducing costs through repeatable processes that capture all elements of the design and implementation of communications systems.

The existing methodologies for the planning, engineering, deployment and maintenance of the Company's telecommunications circuits and equipment use multiple manual processes, data bases, and information sources and heavily rely upon local knowledge of individuals that is at risk of being lost through attrition and retirement. As a result, the status of some telecommunications equipment is not readily or centrally accessible and often requires field investigation to identify the asset information and condition.

Deployment Schedule

The Company has initiated the planning and preliminary engineering efforts for the programs, as it finalizes long-term plans to deploy private fiber and/or microwave technologies into substations and facilities to support currently deployed assets as well as future grid modernization solutions. The proposed fiber optic expansion work along with the wireless network build will take place in CY22-27 with the exception of fiber upgrades at the other key and critical facilities which will occur in CY22-24. Yearly detail of this deployment schedule is shown in Table 14. Phases 2 and 3 of TOMS, which include the implementation of the software and the field survey respectively, will be conducted in CY2022.

Table: 14: Operational Telecom Schedule

Program	CY22	CY23	CY24	CY25	CY26	Total
Tele-protection Upgrades			1			1
Critical & Key Facilities	1	1				2
Analog DS0 Leased Circuit Replacement		6	11	16	23	56
Tier 3 Radio Sites		8	12	21	21	62
DMX Node Replacement	15	14	14	16		59

Status

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

Tier 1 & 2 (Transport Network) The Company is progressing upgrades to its core network, primarily at substations, through testing and evaluation of three leading equipment vendors. Following vendor selection, surveys of the substations will commence, and detailed hardware configurations and designs will then be produced. In the meantime, a limited investment in conversion of DS0 terminal equipment has been proposed under the FY21 ISR for substations requiring immediate action due to the commercial carrier's non-negotiable T1 conversion schedule.

Tier 3 Field Area Network (FAN)

The Company has compared affordable spectrum options and selected appropriate technology that will support requirements of the primary use cases. In advancing development of the proposed solution, detailed network coverage design involving site selection and qualification is being performed to arrive at an accurate total cost for the private network. Field testing will also begin in FY21 with multiple radio vendors covering various technologies and frequency bands.

Network Asset Management Applications

The Company has also finalized evaluation and procurement of the TOMS software. Next steps are to survey and inventory all telecommunications assets throughout Massachusetts. Only in having a detailed snapshot of the current network topology and capability can other network enhancements be implemented in the most efficient manner.

Major Tasks

Tier 1 & 2 Transport Network

Work activities and associated Tier 1 and 2 network upgrades are similar in nature across all the initiatives of increasing fiber connectivity to analog locations, critical and key facilities, and teleprotection sites. At the highest level, the proposed tasks involve the design, build, and operation of newly connected fiber sites. Much of the network design includes cost analysis of whether to install private fiber or use existing service provider circuits. For routes that are shorter in length (i.e., a few miles), the cost often justifies use of private fiber. The majority of the cost for the fiber network build is attributed to the construction of trenching cable in the ground or suspending it on utility poles. A smaller component is the procurement, configuration, and installation of network gear (switches and routers) at the endpoint locations – most often occurring at the distribution substations. RTB costs involve the O&M of the hardware, which given the high reliability of the electronics, a more favorable total cost of ownership may be realized for private wireline networks on sites with these shorter fiber runs.

Tier 3 Field Area Network (FAN)

Over the last 30 years, the cost model for deploying wireless networks has been perfected and optimized by the cellular carriers. In designing and building out the private wireless network in Massachusetts, the Company will follow this deployment model and approach. The design phase begins with radio site selection where coverage and capacity are modeled using sophisticated network planning tools. Existing radio sites such as microwave or land mobile radio (LMR) will be leveraged to reduce cost and establish the anchor design. Site acquisition companies responsible for leasing, zoning, and permitting will assist in identifying other commercial radio sites or new towers located at select substations. Commercial construction companies specializing in radio network builds will perform the deployment work outside of installations in and around power lines. In the Operations phase (i.e., RTB-related work), while the Company currently self-performs these tasks related to network performance, maintenance, and field work, additional contracted O&M services with mission-critical service level agreements (SLA) will be considered to support the increased workload. Outsourcing a good part of O&M on large networks is common in the wireless industry where efficiencies exist in service companies maintaining multiple independent networks around the clock (e.g., state networks involving police or transit along with other municipality or federal networks).

The acquisition of spectrum used for the wireless network is a standard transfer of ownership through the Federal Communications Commission (FCC). Should the Company decide to proceed with a spectrum acquisition, then the expected time frame in completing change of ownership is expected to be approximately 4-6 months.

Network Asset Management Applications

The Company released a request for proposals (RFP) soliciting a telecommunication tool for planning, engineering, commissioning, management, and operations that will enable improved design and documentation as well as telecommunications asset management. This tool will also enable process change and improvement as it is rolled out and provide for documentation and coordination of alarm and monitoring for the network. The tool allows for logical mapping of circuits through most all media including multiple fiber splices and routing.

Incremental

The Communications investment area is an enabling technology that supports all preauthorized investments, including ADA, VVO, ADMS, and M&C. Investments in a robust and effective communication network are required for the other preauthorized investments to optimize system performance (by attaining optimal levels of grid visibility, command and control and self-healing), optimize system demand, and interconnect and integrate distributed energy resources.

Benefits

Telecommunications provides highly reliable connectivity under both normal and degraded system operating conditions. This Operational Communications functionality is a foundational element and supports all other key functionalities. Communications functionality also results in two quantified benefit impacts that are summarized below.

- Avoided Legacy OPEX Investments by avoiding recurring RTB telecoms costs from future DERs. Communications & Networking investments will enable the Company to convert a majority of the existing commercial cellular communications to a private network, thus avoiding monthly cellular fees for future connected DERs. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as “DER RTB telecoms savings” (see Section 4.2.3: Benefit Estimation in the GMP Business Case).

- Avoided Legacy CAPEX Investments by avoiding the cost of converting from DS0 to T1 circuit technology in the near-future. Legacy DS0 telecommunications circuit technology is being obsoleted by commercial carriers. Without investment in a communications network strategy, the Company would need to convert the DS0 circuits to T1 circuit technology by replacing network equipment. This Avoided Legacy CAPEX Investment benefit is included in the GMP BCA as “DS0 to T1 telecoms savings” (see Section 4.2.3: Benefit Estimation in the GMP Business Case).

In addition, the hardened and enhanced core network of Tier 1 and 2 will act as a strong foundation upon which many forthcoming grid modernization initiatives may be added in the future, including backhaul in support of the private wireless network. Specific benefits identified in the Communications & Networking investment, but not quantified at this time, include:

- Operational savings as leased lines are replaced with technology that is more robust and flexible
- Tier 3 connectivity for devices on analog circuits where fiber is cost-prohibitive
- Operational efficiency and overall cost reduction due to combining the many disparate legacy telecommunications systems
- More reliable performance (e.g., uptime, capability) from Advanced Field Devices due to network reliability, flexibility, and scalability, especially where high availability and lower latency are required for devices to function properly. Only in operating a private wireless network can total control of field devices be accomplished to the highest levels of reliability.

<u>Budget</u>

Tables 14 presents the 4-year budget for Communications and Networking. The Company estimates investing $73.88 million through FY 2025. Note that the Company also performed planning work from FY 2019 through FY 2021 to ensure the Company is fully prepared to execute the Network Management projects.

Table 14: Communications & Networking – 4-Year Plan Budget

Communications & Networking	Yr 1	Yr 2	Yr 3	Yr4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
Transport Network CAPEX	$3.73	$6.07	$8.70	$10.83	$29.33
Transport Network WAN OPEX	$1.68	$1.90	$2.02	$2.57	$8.16
Field Area Network CAPEX	$0.13	$14.36	$3.87	$9.09	**$27.45**
Field Area Network OPEX	$1.31	$1.53	$1.57	$1.87	**$6.28**
Network Asset Management Applications CAPEX	$1.14	$0	$0	$0	**$1.14**
Network Asset Management Applications OPEX	$0.32	$0.39	$0.40	$0.41	**$1.52**
Total ($M)	**$8.31**	**$24.25**	**$16.56**	**$24.77**	**$73.88**

3.2.5.5 Integrated Network Operations Center (INOC)

Background

The INOC ensures proper operation of a communication infrastructure supporting multiple business services over a hybrid network. It provides a single point of contact for support and operations through a cross-functional set of people, processes and technologies. The INOC is a central location from which network administrators manage, control, troubleshoot and monitor one or more networks. The overall function is to maintain optimal network performance across a variety of platforms, mediums, networks, network segments and communications channels. An INOC is similar to a Dispatch Control Center used for managing the electric grid, and the Network Operation Center for all IS-related items that support the grid. The INOC would monitor the health and behavior of all aspects of the grid device level communications and network using an Operation Support System (OSS) and have the capabilities to provide a first level of incident response. Monitoring, provisioning and configuring are accomplished by computer-based tools that create alarms when anomalous activity, performance issues or system failures are detected. National Grid's grid modernization investments will provide many new business services and providing a single point of contact for these services is key to their efficient operation, will eliminate the risks of a point to point system in an electric grid with a greatly increased number of systems and will provide a better customer experience. An INOC is typically a secure physical room or facility with computers along with dedicated systems and appliances that monitor the network and communication systems using various software such as commercial off the shelf (COTS) management suites and open source applications, along with the built-in logging mechanisms of all network infrastructure systems themselves. Screens display real-time systems information and have the ability to display alarms for sub-optimal performance.

National Grid is currently running multiple monitoring platforms across different network architecture domains leading to fragmented issues/incidents resolution and network performance monitoring. These monitoring solutions operate in silos and do not provide a real time integrated information to operators to take corrective actions on time.

Goals and Objectives

INOC as a centralized communication networks will be the heartbeat of National Grid where it will be comprised of different protocols, vendors and service providers including public and private resources to be monitored from a substation to the edge consumer, as one logical end to end network. This will have the greatest impact to improving communications service outage restoration and accommodate more proactive response increasing customer demands. The INOC is a foundational element required to become a flexible grid and be able to provide on demand services. As we transform legacy networks to Next Generation of technology, National Grid needs to build more robust resilient network monitoring solution using INOC to be able to manage and operate the transformational network.

Given the exponential growth of varied kind of network devices and platforms it is difficult to meet higher service level agreements (SLA) using legacy monitoring systems. In order to maximize operational benefit and meet required SLA, it is highly critical to migrate to a centralized and integrated Network operations center which can provide real value to the growing needs of distribution network.

INOC capabilities to be enabled through this investment include:

- Manage, monitor, and report on the Network performance of SLAs against negotiated thresholds.
- Monitor and manage the availability of the LAN and WAN, including wired and wireless communications, to ensure availability requirements are met. Networks are prioritized based on the criticality of the services they support.
- Monitor and manage the capacity of LAN and WAN communications, including wired and wireless communications, to ensure they are performant.
- Monitor and coordinate any changes to the system; ensuring all changes are communicated and have rollback and testing times.
- Monitor and report on total round-trip time of application or network latency between endpoints.
- Characterize and drive remediation of incidents that could lead to, or have caused, a loss of service, as defined by the SLAs.

Deployment Schedule

In October of 2020, the Company initiated a review and assessment effort for the INOC investment area. The Company issued an RFP on October 29, 2020, seeking consulting services to support the development of a framework and approach for progressing an INOC effort including the following: an assessment of the people, process and technology aspects, a service level basis for Service-Level Agreements (“SLAs”) and Operation-Level Agreements (“OLAs”) and an overall investment and business case structure. The vendor was selected in December 2020 to perform the review and assessment of INOC. The implementation effort to deliver a Minimum Viable Product (MVP) for INOC services will be mobilized in 2021.

The project team will develop detailed solution requirements for the MVP including various business use cases and operational aspects. The project will then develop multiple workstreams comprises of Business process design, detailed design and technical architecture required to identify the hosting platform, software products and integrations needed for the delivery of enterprise grade INOC solution. Once the detailed design and architecture work is completed and any necessary software products are procured / developed, the Company would proceed to implementation and solution delivery. After the successful release of MVP the Company planned to rollout additional INOC capabilities supporting various business needs in an incremental digital delivery.

The Company also planned to release an RFP to choose a right vendor solution for INOC based on the business outcomes. The decision of buy vs build solution for INOC will be determined based on Feasibility & Analysis study.

Incremental

The Communications investment area is an enabling technology that supports all preauthorized investments, including ADA, VVO, ADMS, and M&C. Investments in a robust and effective communication network are required for the other preauthorized investments to optimize system performance (by attaining optimal levels of grid visibility, command and control and self-healing), optimize system demand, and interconnect and integrate distributed energy resources.

Benefits

These capabilities collectively will provide the following benefits:

- By bringing the systems into an insourced model, teams that rely on those services and projects that need modifications to those services should perceive and receive an increased level of customer service leading to greater satisfaction.
- By implementing toolsets owned and managed by National Grid, the support teams will have far greater access to current configurations and issues that may be occurring which could lead to better abilities to plan and strategize going forward. This will result in insights and motivation to improve the network to reduce incident counts.
- By implementing advanced toolsets and utilizing strong datasets for analytics, proactive support measures should be able to be implemented over time, reducing overall incidents, outage durations/impact, and avoiding some outages completely.

- By implementing a combined support model, lessons learned can be shared across multiple organizations, and processes and toolsets will be identified that can benefit multiple groups at once, and in turn lead to more standardization and efficiencies between processes and toolsets.
- By creating a successful combined support model with clearly defined tools and processes, new solutions should be easier to integrate into the existing models leading to quicker time to market and deployment.

Budget

Table 15 presents the 4-year budget for INOC. The Company estimates investing $11.09 million through CY 2025.

Table 15: INOC – 4-Year Plan Budget

INOC	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Total**
	CY 2022	**CY 2023**	**CY 2024**	**CY 2025**	**CY22-25**
CAPEX ($M)	$3.56	$4.09	$1.74	$0	**$9.39**
OPEX ($M)	$0.29	$0.34	$0.01	$1.06	**$1.70**
Total ($M)	**$3.86**	**$4.43**	**$1.74**	**$1.06**	**$11.09**

3.2.6 Existing Metrics

Performance Metrics

Regarding the performance metrics proposed by the Companies in the GMPs, the Department determined that additional work was needed to develop metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the Grid Modernization objectives. Order at 195-206. The Department ordered the Companies to file revised proposed performance metrics designed to address the preauthorized grid-facing investments and noted that it would convene a stakeholder process to facilitate review of the revised performance metrics. Id., at 202.

On July 11, 2019, the Companies jointly submitted revised performance metrics, "Grid Modernization Performance Metrics, Revised July 11, 2019" and on July 25, 2019, the Companies received the stamp-approved copy of this document, without changes to the original submission. The performance metrics were reviewed and are generally unchanged except for VVO metrics. The original VVO metrics were developed prior to engagement by Guidehouse or before the system was fully deployed and operational. Guidehouse has since collected significant data and started their data analysis. The revised VVO performance metrics were amended to resemble the methods Guidehouse utilized in their evaluation. These changes were also outlined in the revised Stage 3 Evaluation plans submitted on December 1, 2020 in D.P.U. 15-120, 15-121 and 15-122, and also as responded to in information requests DPU-EP-1-1 (submitted February 6, 2020), DPU-EP-1-8 (submitted January 30, 2020), and DPU-EP2-1 and 2-4 (submitted on April 28, 2020) in those dockets. The performance metrics document can be found in Exhibit NG-GMP-4, with suggested changes made in a redlined format for consideration.

Additionally, with the evolving nature of the GMP, additional investment types have been added and therefore additional performance metrics are being proposed to measure progress towards the objectives of grid modernization. The Companies have jointly worked together on two proposed state-wide performance metrics and two additional company-specific performance metrics. All four proposed performance metrics are summarized below and are elaborated in Exhibit NG-GMP-5.

Infrastructure Metrics

As part of D.P.U. 15-120/15-121/15-122 the Department approved the Companies' proposed statewide and company-specific infrastructure metrics. Id., at 198-201. The Department ordered the Companies to establish baselines by which the grid-facing performance metrics will be measured against and to file them within 90 days of the Order. Id., at 203. On August 15, 2018 National Grid filed the "Grid Modernization Plan Statewide and National Grid-Specific Infrastructure Metrics Baselines and Targets". The Company does not recommend changing these infrastructure metrics at this time.

3.3. New Technologies

3.3.1 Distributed Energy Resource Management System (DERMS)

3.3.1.1. DERMS Investigation

Background

There is tremendous opportunity to tap into the grid benefits of the rapid deployment growth of DER within Massachusetts if they can be utilized to holistically optimize the electric power system. Although one step is to assess the value of DER and develop the associated tariffs and programs, the complementary step is to integrate and manage beneficial DER in system planning and operations. Some of the demonstration projects proposed in the Company's grid modernization plan seeks to gain experience of this latter step in managing DER around grid needs.

However, in parallel to these demonstration projects, there is a need to consider the broader vision of how the Company will incorporate comprehensive DER management capabilities into its current business processes and operational systems in a cost effective and optimal manner through DERMS and a DERMS Platform. Investments in DERMS will work hand in hand with existing grid modernization investments such as line sensors, IT, SCADA, ADMS, VVO, and Data Management Platform to support the Department's grid modernization objectives to optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing, optimize system demand by facilitating consumer price responsiveness, and interconnect and integrate DER .

What is DERMS and DERMS Platform

The DERMS Platform is a group of individual applications managed by the Company that operate together in a cohesive fashion to actively track, plan, manage and operate DER that are interconnected on circuits that are below 100 kV through monitoring and control either directly or via an aggregator. The DERMS Platform will maintain or improve the reliability, resiliency, efficiency and overall performance of the electric distribution system in a DER-centric world.

DERMS is a software/s that form the hub of DER management functions and integrates with other applications such as DRMS (Demand Response Management System) and ADMS, to create the DERMS Platform. The Company intends this software to be enterprise-wide and as a full-scaled solution available to all areas of the Company's service area.

Common DERMS Platform use cases include: interconnection of DERs, DER registration, DER program enrolment, long term DER planning, operational DER planning, DER operations and DER settlement.

Goals and Objectives

This DERMS investigation project is to fully prepare the Company for an enterprise-wide DERMS and associated DERMS Platform deployment that will build upon the foundation established by the

Company's ADMS project. This DERMS investigation project is akin to the Company's earlier efforts to prepare for ADMS, including definition of the business and functional requirements, identification of necessary data interfaces with other utility enterprise systems (e.g. MDMS, ADMS, CIS, etc.), the procurement plan of the associated software platforms and preliminary budgets associated with the implementation plan. National Grid anticipates that all functionality required for the utility to manage DER in the grid of the future will likely be supplied through multiple applications that collectively represent the DERMS Platform.

As discussed in the 5-year strategic plan, DERMS is a key software and management capability. The Company has some limited capability to monitor and control DER today (i.e. monitoring and connect/disconnect capabilities via PCC reclosers for DER above a specific size and management of behind-the-meter DER in the Company's Demand Response programs through its DRMS or DERMS 1.0 as supplied by EnergyHub for system peak load reduction. However, following a recent and preliminary DER management capability gap analysis, the Company identified 18 DER management capability gaps not provided by the Company's current DER management software tools. These gaps need to be filled over approximately the next five years to enable to Company to manage DER effectively to support the state's clean energy goals. The proposed demonstration projects described in this grid modernization plan will provide key inputs to best consider approaches to fill in these capability gaps identified and validate assumptions, whereby the DERMS investigation project will be taking outcomes from these demonstration projects to inform and scale a future enterprise-wide DERMS 2.0 investment, to be referred to simply as DERMS onwards.

Conducting due diligence to determine the most valuable and optimal deployment of DERMS is essential to ensure customer funding is effectively spent before making any significant DERMS investments. The output from this investigation will be a fully specified DERMS investment and implementation plan.

Optimal operation and management of DER through the deployment of a DERMS Platform can result in numerous customer benefits, such as: (1) avoiding or deferring system upgrades to integrate DER into the grid via optimal dispatch of DER; (2) operationalizing DER to provide grid services that can further increase the value of DER to all stakeholders and (3) offering innovative programs that interact with customer DER. Some of these benefits can be realized through use cases such as greater deployment of non-wire alternatives, integration of DER into VVO, and improved DER coordination with ISO-NE. DERMS serves as an enabling technology of these use cases and others through its ability to efficiently manage and automate DER management tasks especially in light of the levels of DER deployment and integration anticipated in the next few years and beyond.

DERMS Investigation Schedule

The following table presents the Company's timeline for its DERMS preparation project.

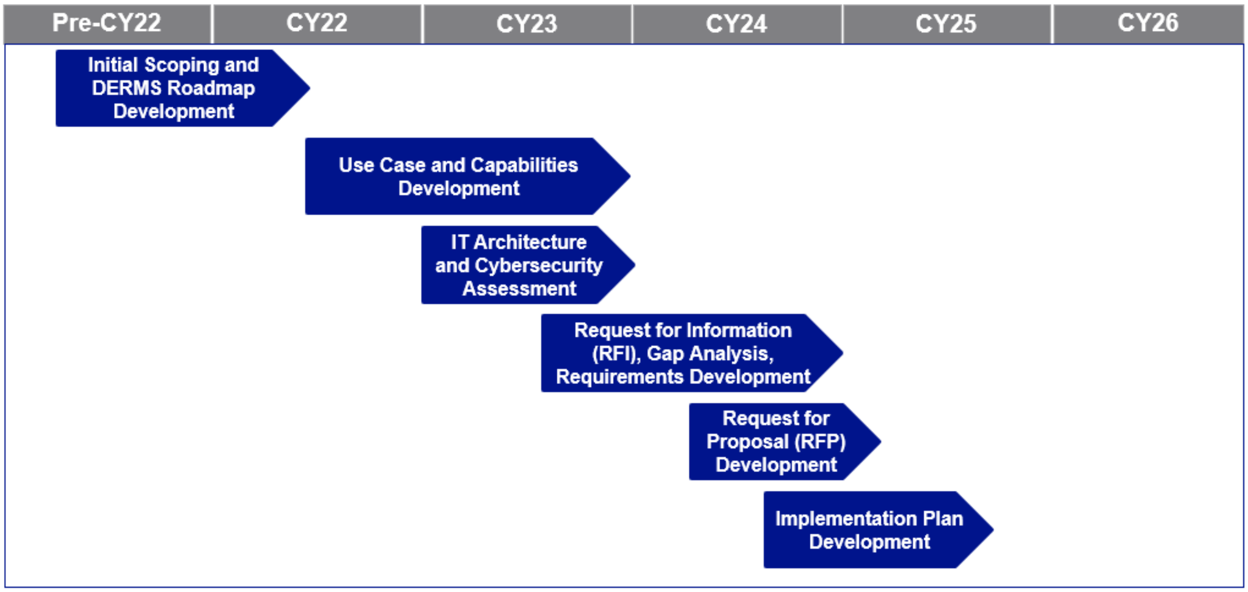

Figure 19: DERMS Schedule

Major Tasks

Before initiating a major investment in the deployment of a new enterprise solution focused on DER management, the Company will utilize this DERMS investigation project to assess the business and customer values that a DERMS platform would offer and develop the detailed use cases driven by those values. This investigation would then translate those detailed use cases into business and technical capabilities and associated requirements. As the Company today already manages to some extent some of the capabilities required for management of DER such as interconnection, the Company's existing and planned systems will be fully examined to identify any remaining gaps to reach the desired future state for its DERMS platform. As use cases likely will vary in scope, capabilities and complexity, a multi-phased implementation approach for the DERMS platform may be most suitable.

The scope of this DERMS Investigation project includes the following key tasks:

- Identification of detailed DERMS use cases, requirements and capabilities for enterprise-wide DERMS with regards to:
  - **DER interconnection** which may include managing interconnection application process, data and agreements
  - **DER registration** which may include customer interaction and recording of individual DER settings, capabilities, control modes, etc. as needed and any coordination with the ISO-NE as necessary (e.g. FERC Order 222 implementation)

    - **Program enrollment** which may include managing utility DER program rules, terms and conditions, coordination and aggregations
    - **Long term DER planning** which may include Identification and inclusion of potential DER solutions to long term planning constraints and derivation of locational value of mitigating these constraints in conjunction with the Company's integrated planning process
    - **Operational DER planning** which may include forecasting DER capability based on short-term load forecasts, DER ISO schedules, identifying distribution constraints due to DER operation and performing security constrained economic dispatch possibly in conjunction with ADMS, identifying locational value to mitigate system constraints, and operational coordination with the ISO-NE as necessary (e.g. FERC O222 implementation)
    - **DER operation** which may include monitoring real-time system conditions and constraints in conjunction with ADMS, facilitating near-term or real-time dispatch or re-dispatch of DER such as for ISO-NE and/or utility schedules or reliability needs to maintain grid security
    - **DER settlement** which may include measurement, verification and the associated calculations to determine DER performance against any contracted or enrolled utility program obligations or utility tariffs, and storing of historical dispatch requests and DER performance to utility dispatch requests
- Development of a detailed DERMS capability gap analysis based on any existing DER management capabilities and the required capabilities that the Company anticipated on a 10-year outlook basis, and a DERMS roadmap to address the identified capability gaps
- Identification of any interim Minimal Viable Products (MVPs) that can be implemented in an agile deployment approach and may build on demonstration projects proposed previously
    - MVPs may be necessary to help validate major technical or business assumptions identified in this investigation
    - Details will be determined as the DERMS Investigation project is conducted
- Assess existing and need for new IT/OT infrastructure and overall DERMS architecture to address the following areas:
    - Archival of historical data associated to DER in a database and the Company's PI Historian
    - Development of detailed DERMS Platform IT diagrams
    - Specifications for data interfaces and integration between applications within the DERMS Platform and to other enterprise utility systems (e.g. GIS, CIS, ADMS, customer facing portals, business to business interfaces and legacy technology integration, etc.)
    - Data formatting and standardization
    - Cybersecurity and physical security requirements and considerations including protocols, firewalls, compliance and testing
- Roles and responsibilities, resource requirements and training identification required for Company users and departments

- Control Center displays and dashboards including alarm management and operator display design to incorporate increased availability of DER information and considering usability, simplicity and consistency with existing operator interfaces
- Development of a detailed Benefit Cost Analysis of DERMS
- Conduct vendor interviews and Request for Information (RFI) to inform the Company's investigation efforts
- Development of a Request for Proposal (RFP) in preparation for future enterprise-wide DERMS investment

Budget

Table 16 presents the 4-year budget for the DERMS Investigation. The Company estimates investing $1.90 million through CY 2025.

Table 16: DERMS Investigation – 4-Year Plan Budget

DERMS Investigation	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	**CY 2023**	**CY 2024**	**CY 2025**	**CY22-25**
CAPEX ($M)	$0.14	$0.19	$0.20	$0.05	**$0.58**
OPEX ($M)	$0.34	$0.34	$0.63	$-	**$1.32**
Total ($M)	**$0.49**	**$0.53**	**$0.83**	**$0.05**	**$1.90**

3.3.1.2 DERMS Implementation

Background

The DERMS Investigation described above is to ensure the Company is fully prepared for full enterprise-wide DERMS implementation with implementation plan to subsequently follow through this project. At this time prior to the DERMS Investigation project, we believe DERMS must have core capabilities that include interconnection, resource registration, program enrollment, long term DER planning solutions, operational planning, real time operations and settlement

The Company's initial DERMS experience has been in support of the Company's demand response (DR) programs, which are generally supported through a Demand Response Management System (DRMS, now known as DERMS 1.0) that has only focused to date on reducing system peak load.

Goals and Objectives

This project will implement capabilities such as software features, integration with other IT/OT systems and new processes to fill the capability gaps identified through the Company's DERMS investigation in order to effectively manage and leverage DER to help meet the state's climate goals. The Company currently anticipates that full implementation of DERMS and the associated DERMS Platform will take approximately 3 years, subject to the outcome of the DERMS Investigation project and the ability to pivot should the need for capabilities change. The objective is to leverage this implementation in practice via daily control center operations to maximize DER operations and operation of the grid for all customers and value extraction for the DER owners.

Deployment Schedule

The timing of the Company's DERMS implementation is dependent on the findings from the Company's DERMS Investigation that will assess the prioritization of appropriate DERMS 2.0 use cases and capabilities and that will be informed by DER penetration, evolving DER policy requirements, evolution of wholesale and retail markets and customer programs, and the need for enhanced operational and economic dispatch. The Company's DERMS implementation plan, a deliverable of the DERMS Investigation, will establish the expected timing of need for and deployment of the DERMS capabilities, which likely will take a phased approach.

Therefore, National Grid anticipates that following the conclusion of its DERMS Investigation, its DERMS implementation efforts will begin in CY 2025. The Company acknowledges that the details for its DERMS implementation and associated costs starting in CY 2025 are still largely uncertain at this time, and requests that the estimate for CY25 will be provided as soon as possible at a later date per the Department's D.P.U. 20-69-A Order at p. 38, n. 17, whereby refined costs would be provided through the DERMS investigation project.

Status

The Company does not have any active programs to implement DERMS specifically targeting areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER. However, the Company has deployed a DRMS (DERMS 1.0) in support of the Company's demand response programs, which can also be considered a behind-the-meter (BTM) DERMS in that it is being used to manage Wi-Fi thermostats, electric vehicles, batteries, generators, CHP, HVAC systems, lighting systems, industrial processes, and other BTM DER. Current BTM DERMS functionalities include handling customer/vendor registration, event dispatch, and performance calculations. However, the management of FTM resources such as power plants, solar farms, and Company-owned resources are not within the purview of the energy efficiency portfolio nor is localized grid operation of DER as DERMS 1.0 is only focused on system peak load reduction.

Major Tasks

Over the next five years, the Company plans to complete the DERMS investigation project and begin full enterprise DERMS implementation thereafter. Details on the major tasks for full DERMS implementation will be identified as an outcome of the Company's DERMS investigation project, however the Company may provide major tasks related to CY25 investments when the Company has better understanding of the scope planned for CY25 and has provided the estimate for the DERMS Implementation project for CY25 at a later date.

Benefits

DERMS primarily provides DER Operational Control functionality, but DERMS also enhances Grid Optimization functionality. DER Operational Control functionality results in the qualitative benefit impacts summarized below.

- Greater opportunity to realize multiple value streams of DER for DER owners through broader optimization and integration of DER with the grid
- Greater levels of operation and management of DER to ensure continued safe and reliable operation of the grid
- Increased efficiency of planning and operating the grid by leveraging DER
- Reduced DG Curtailment (when coupled with ADA, ADMS, and other supporting solutions) due to the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximize the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance
- Improved DER experience can be realized (when coupled with ADMS) by streamlining DER interconnections and potentially reducing interconnection costs and enabling larger DER interconnections, which can make DERs more cost effective to deploy

Budget

Table 17 presents the 4-year budget for the DERMS Implementation. The Company will provide a detailed budget through a supplemental filing.

Table 17: DERMS Implementation – 4-Year Plan Budget

DERMS Implementation	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025[29]	CY22-25
CAPEX ($M)	$0	$0	$0	TBD	TBD
OPEX ($M)	$0	$0	$0	TBD	TBD
Total ($M)	**$0**	**$0**	**$0**	**TBD**	**TBD**

3.3.1.3 Advanced Short-Term Load Forecasting

Background

A key DERMS foundation akin to ADMS is Advanced Short-Term Forecasting capabilities. As greater levels of distributed generation and dynamic loads such as electric vehicles and electric heat pumps connect onto the distribution system, short-term load forecasting ("STLF") becomes simultaneously more challenging to perform as well as more crucial to efficient distribution system operations. There has also been a growth of research and commercial solutions providing advanced STLF capabilities in multiple industries including the energy sector that leverage the expanding use of machine learning practices to help increase situational awareness. This advancement in STLF look to incorporate other available datasets with more granular measurements such as AMI and localized weather data. [30]

[29] The Company will make a supplemental filing as soon as possible with its proposed budget for CY2025 for its DERMS implementation. D.P.U. 20-69-A at 38 n.17.
[30] Rolnick et al. Tackling Climate Change with Machine Learning. https://arxiv.org/abs/1906.05433v2. p. 7, 2019.

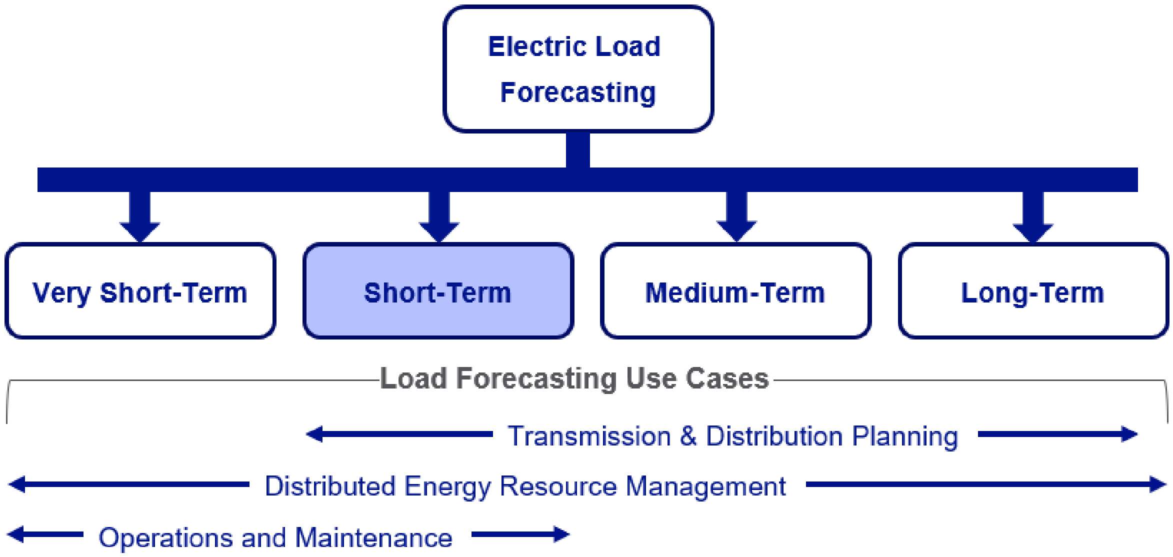

Figure 20: Types of Load Forecasting

STLF in this context is typically characterized as a prediction of electric load associated with the entirety or various subsets of the Company's EPS. Today the Company utilizes day-ahead system-wide and regional system load forecasts to support system peak reduction measures and wholesale energy procurement activities. However, National Grid sees a growing need to understand potential short-term loading and constraints on its system at a much more granular geospatial and temporal perspective and utilizing more diverse datasets to inform operational planning and decisions.

Goals and Objectives

In the future grid where digitalization can enable greater levels of grid modernization and integration of DERs, there will be opportunities to improve operational efficiency such as through the investment and deployment of advanced data analytic tools that leverage machine learning techniques with complex datasets. Therefore, National Grid has identified advanced STLF ("ASTLF") capabilities as a key enabler to support other grid modernization initiatives and investments such as ADMS and DERMS and has a role in optimizing system performance and integration of DER.

To manage the grid in the future, the Company aspires to utilize AMI and hyperlocal data to build a bottom-up forecast (i.e., premise-level forecast) that can be ingested by various utility applications, such as ADMS and DERMS. Until AMI data is available, the Company plans to deploy top-down ASTLF capabilities in the near term that will be a beneficial step in building experience and expertise within the Company in using weather-based forecast modelling combined with machine learning techniques to produce more accurate load forecasts. The Company's New York affiliate has an ongoing proof-of-concept that is demonstrating the ability of this top-down approach for a limited number of substations and feeders.

The Company proposes to deploy ASTLF capabilities first to support its ADMS deployment and provide near-term benefits to improve distribution system operations, with the intent to later integrate ASTLF capabilities into its enterprise-wide DERMS implementation. Advanced identification of system constraints utilizing day-ahead to week-ahead load forecasts from the integration of ASTLF and ADMS will enable the Company to further optimize system performance through improved grid visibility of the impacts from DER. The significant increase of DER on the distribution system will result in greater levels of uncertainty in system load profiles and therefore certain datasets such as solar irradiance and cloud cover become critical to enhance the Company's load forecasting capabilities. Similarly, advanced identification of system constraints can also enable the Company to better integrate and utilize DER through DERMS to respond to system constraints such as through activation of demand response and non-wire alternative resources and potential other future programs.

Benefits

ASTLF supports and enhances other applications and tasks associated to Grid Optimization and Operational Analysis through the availability of granular, short-term load forecasts. This investment is expected to provide qualitative benefits through enabling or enhancing the following associated use cases:

- Improved Operational Efficiency through advanced notification of granular forecasted system constraints using ASTLF and integration of load forecasts with ADMS applications (e.g., load flow simulation and contingency analysis) that can better inform distribution system operational planning, optimal system reconfiguration, what-if studies and scheduling of field workforce

- Improved DER Experience and Operation by using more accurate short-term load forecasts as input into distribution system security analysis and feasibility assessment of DER schedules, especially for DER participating in the ISO-NE wholesale market

- Improved DER Utilization and Operational Efficiency due to greater certainty of near-term system needs informed by ASTLF which can lead to more efficient activation of DER programs for grid services through DERMS, and the opportunity to evolve how the Company can use the growing deployment of demand response, distributed generation and storage resources to support system needs and balancing load and supply on the system

Deployment Schedule

The proposed ASTLF investment and deployment plan will follow completion of an internal proof-of-concept by the Company's New York affiliate. Lessons learned from that demonstration will inform solution requirements for a Phase 1 scope of deploying an enterprise solution for ASTLF that will be designed and implemented through CY22-24 of the plan. Upon the initial release of the ASTLF system, Phase 2 of the ASTLF project will begin development, training and validation of the forecast models and integration with the ADMS load flow capabilities to align with ADMS Phase 2 objectives and DERMS implementation thereafter.

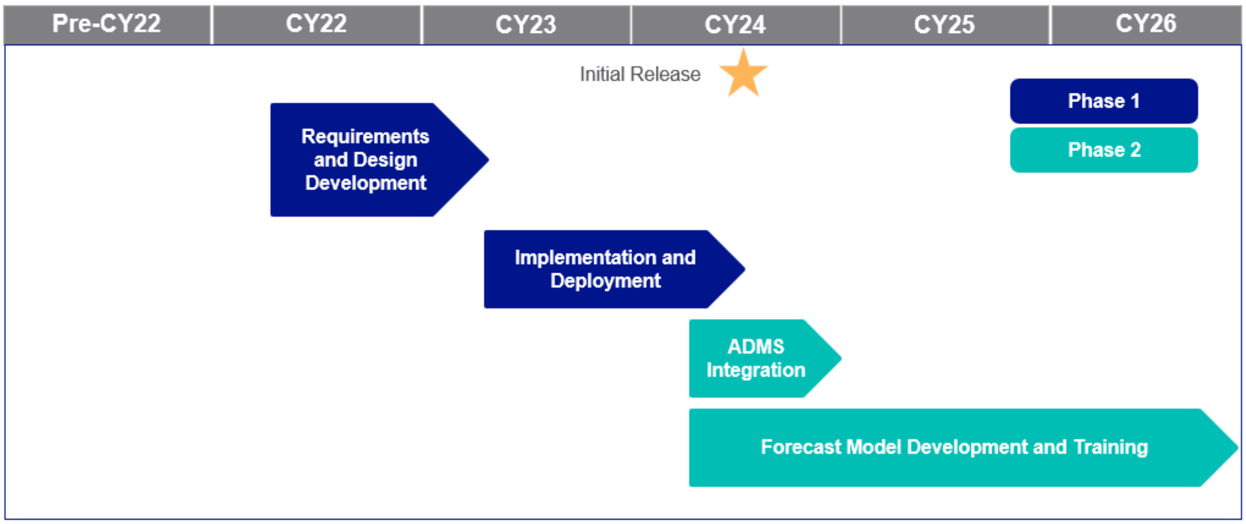

Figure 21: ASTLF Deployment Plan

__Major Tasks__

Phase 1 includes developing the solution requirements for ASTLF including various business use cases (e.g., data analytics, DER programs) and operational needs (e.g., integration with ADMS load flow application and forecast reports to the Company's Control Center) to detail the scope and plan of the solution for grid modernization. The project will then develop the detailed design and architecture required and identify the software products and integrations needed to deliver the full solution. Once the detailed design and architecture is completed and any necessary software products are procured, the Company would proceed to implementation and solution delivery.

The ASTLF capabilities will require integration to other utility enterprise system and data repositories that will utilize the efforts being proposed under the Company's proposed Data Management investment. Initially, ASTLF will utilize various datasets including historical system data from the Company's PI historian and local weather data. In the future, the Company anticipates other datasets that may include energy market, AMI and DER data to serve as additional inputs to ASTLF as they become available and as the Company identifies the associated use cases.

In Phase 2, the Company will have completed the setup of the core ASTLF capabilities and will begin developing, training and automating forecasts for targeted feeders and substations that are anticipated to align with the rollout of feeders being modelled in the ADMS project. The Company also expects to begin integration to transfer forecast outputs from the ASTLF system to ADMS and test the ability to run simulations using forecasted system loading data. As part of this work, the Company will work with its current ADMS vendor on enhancements to support importing a top-down forecast or consider future load forecasting capability that can produce a bottom-up premise level forecast utilizing information such as AMI data to support ADMS applications.

A future phase of ASTLF will be to integrate with the Company's DERMS project. Details of this integration will be further investigated and proposed as part of the development of the Company's DERMS implementation plan anticipated in CY25.

Budget

The table below presents the 4-year budget for Advanced Short-term Load Forecasting, which include investments in underlying IT infrastructure, software and data services. The Company estimates investing $5.98 million through CY25.

Table 18: Advanced Short-Term Load Forecasting – 4-Year Plan Budget

Advanced Short-Term Load Forecasting	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$1.85	$0.58	$-	$-	**$2.43**
OPEX ($M)	$0.75	$1.22	$0.78	$0.81	**$3.55**
Total ($M)	**$2.60**	**$1.79**	**$0.78**	**$0.81**	**$5.98**

3.3.2 FERC Order No. 2222

Background

In September 2020, FERC issued Order No. 2222 ("FERC O2222"), requiring that all ISOs/RTOs allow aggregations of distributed energy resources (DERs) to provide, and receive compensation through market participation, for all wholesale services for which they are technically capable (energy, capacity, and ancillary services). The Order includes several directives to shape the compliance approach for the individual ISOs/RTOs, including the requirement that the associated market participation models must permit heterogeneous aggregations of DER (DER Aggregation, or "DERA"), where aggregations can contain a mix of load and generator DER assets such as PV, energy storage, smart thermostats, electric water heaters, EVs, and demand response. Since DER by definition are connected at the distribution level, FERC O2222 will require considerable coordination between the ISOs / RTOs, the distribution utilities, and the DERA market participations to ensure that (a) DERAs are efficiently integrated into markets in a way that results in an overall lower cost resource mix that benefits all load customers and

(b) that DERA operation does not compromise the reliably and safety of either the transmission or distribution systems.

The Company has taken an active role throughout the ISO-NE FERC O2222 stakeholder engagement process to ensure that the resulting market rules carefully consider the roles, responsibilities, capabilities, and expectations of the distribution utilities. ISO-NE initiated its stakeholder engagement process through the NEPOOL committee structure in December 2020 with a high-level presentation that defined key components of FERC O2222 and solicited initial "issue spotting" feedback from stakeholders to help shape the ongoing stakeholder meetings. The Company participated in this early solicitation by submitting a memo on stakeholder engagement topics and issues for further discussion. Since this December 2020 meeting, the Company has continued to participate in all virtual NEPOOL forums and relevant working groups, including submitting additional written comments to ISO-NE and presenting an accompanying slide deck at the June 2021 NEPOOL Markets Committee and Transmission Committee meetings.[31] Outside of the NEPOOL structure, the Company has continued to lead on this topic through meetings and presentations with external groups including the other New England EDCs and DPU. Where possible the Company has leveraged learnings from our New York operating company to share our experience working through NYISO on their similar DER aggregation model. The Company recognizes the importance of creating practicable opportunities for customers to leverage the full value of their DERs, including wholesale market opportunities through FERC O2222, as a key driver to maintain and accelerate the pace of DER adoption in our Massachusetts service territory.

There is still some uncertainty related to the forthcoming DERA market participation models in ISO-NE and the associated timing for when such models will be operational in ISO-NE. ISO-NE has indicated that their compliance approach will be to design two new participation models -- a Settlement only DER Aggregation (SODERA) and a Dispatchable DER Aggregation (DDERA). The exact rules for how these participation models will be implemented in ISO-NE is still uncertain and is subject to further iteration through the stakeholder engagement process. ISO-NE has requested an extension with FERC that would delay their filing date from July 2021 to February 2022 with actual implementation of the associated market rule perhaps as late as 18-36 months beyond February 2022 depending on FERC's ruling on ISO-NE's compliance filing.

Goals and Objectives

While some of the implementation details have not yet been fully resolved, the Company has identified what we believe will be the key challenges to the distribution utilities in implementing and facilitating FERC O2222, as well as some of the related required capabilities and investments to properly support DERA participation in the ISO-NE wholesale market. The Company's goal is to be proactive in its proposal of the known and certain cost elements associated with FERC O2222 in this filing to ensure we are prepared to adequately and fully support DERA participation in wholesale markets on "day one" of market implementation. We believe this approach positions the Company to maintain its role as a

[31] "*National Grid Comments on ISO-NE Conceptual market Design Approach for Compliance with FERC Order No. 2222*," June 2, 2021. https://www.iso-ne.com/static-assets/documents/2021/06/a04c_mc_2021_07_08_09_ngrid_memo.pdf

leader among the distribution utilities in understanding the complexities of DERA wholesale market participation and the role of the DU in supporting such participation to accelerate customer DER adoption.

The investments to support FERC O2222 identified in this section directly align with the broader Grid Mod objectives and accordingly are appropriate to include in this filing.

- <u>Optimize system performance by attaining optimal levels of grid visibility</u>: The investments included to support the operational components of FERC O2222, such as the DERA operations portal described below, would provide the Company with increased monitoring and control of the individual DER participating in wholesale market DERAs to ensure safety and reliably of the distribution system.
- <u>Optimize system demand based on consumer price responsiveness</u>: More broadly, the Company investing in the proper tools to review and register, accurately settle, and safely monitor DER participation in wholesale DERAs enables practicable opportunities for customer DER on the distribution system to more actively manage their resource in response to wholesale market price signals that are reflective of the bulk grid system conditions.
- <u>Interconnect and integrate renewables</u>: The investments to support the Company's ability to facilitate an expeditious DERA registration and review process will result in faster interconnection of new DER that intends to operate as part of a wholesale DERA and faster integration of existing DER into wholesale DERAs.

The chart below defines the relevant topic areas, the challenges to the Company, and the required capabilities and associated investments that the Company may request to implement to support wholesale market participation of DERA.

Topic Area	**Challenges to the Company**	**New Capabilities Required**
DERA Registration – Technical Review	The intended operation of the DERA cannot compromise the reliability/safety of the distribution system.	Incremental FTEs in distribution planning to support DERA distribution impact studies
DERA Registration – Non-technical review	The DERA needs to be wholly eligible to enroll in the wholesale market, and their participation cannot result in double counting of payments/charges for wholesale settlement.	Incremental FTEs in customer energy integration to manage DERA registration process
Operational Coordination	There needs to be a secure communications framework for the distribution company to	DERA operations portal

	monitor cleared DERA bids, communicate outages, and override ISO-NE dispatch of DERAs to secure reliability/safety of the distribution system.	Dual-participation distribution management study Incremental FTEs in electric control centers to complete day-ahead and real-time distribution security analysis based on DERA bids
Metering/settlement	The metering/telemetry requirements for participating DER need to be adequate and practicable to support accurate and timely settlement.	Settlement system upgrades Incremental FTEs in meter data services to support meter reading for wholesale/retail settlement of DERAs and associated administrative work

The Company recognizes that we may identify additional capability gaps associated with FERC O2222 in the future as the DERA participation market rule revisions are finalized in ISO-NE and we prepare for implementation. As such capability gaps are identified, the Company expects to align with the Department on appropriate regulatory pathways for any associated costs. The Company plans to continue working with relevant stakeholder groups including DPU to understand how we can best deliver on our roles and responsibilities in supporting DERA wholesale market participation. The Company also acknowledges that creating the right processes for equitable cost recovery for certain elements may involve working through regulatory channels outside of Grid Modernization such as through the DG interconnection tariff or other appropriate venues. Similarly, we would expect to work carefully with DPU to ensure proper modifications are implemented to existing and future tariff-based retail programs for clarity on issues related to dual-participation, such that customer DER are appropriately compensated for the services they provide without double-compensation for the same service. The Company looks forward to continued dialogue with DPU as these topics evolve.

Supporting Projects

In this section, the Company identifies the capabilities and associated costs required to support FERC O2222 for which we are proposing cost recovery for in this filing. For each of the below items discussed, we identify if that particular cost item is driven primarily by FERC O2222 (i.e., if O2222 and the forthcoming wholesale market changes did not exist, we would not be proposing this change) or by another use-case but could also be used the Company to enable certain elements related to O2222. For this latter category, we describe how that capability would help enable O2222 functionality but note that the associated costs for these items are included elsewhere in the filing. This determination is because we do not anticipate incremental costs resulting from O2222 at this time.

DERA Operations Portal

The Company proposes to develop and maintain a DERA operations portal (DOP) to collect and transmit information between the DERA and the Company. The Company asserts that the DOP will be necessary to facilitate proper information sharing to minimize the impact of DU operations needs on ISO-NE real-time market operation and DERA participation while ensuring distribution system safety and reliability. Notably, the DOP will be critical to facilitate the required analysis of DERA in the Company's distribution control center to confirm day-ahead and real-time security of the distribution system. The DOP will serve two primary functions.

1. Communicate system outage information to DERAs. DOP will communicate scheduled distribution outages/planned work that may impact DERA bids to DERA market participations. The DOP will pull system conditions directly from the Company's internal operations software system (i.e., the TOA system).

2. Receive granular DER dispatch from DERAs. The DOP will be used by DERA Aggregators to communicate 24-hour granular DER schedules to the Company. ISO-NE will award dispatch instructions to the DERA as a whole, which will include fairly broad geographies based on metering domains and ISO-NE demand response aggregation zones. Based on these geographical limitations DERAs could certainly span multiple substations and several feeders. Therefore, the Company will need to utilize the DOP to receive DER information mapped more granularly to the distribution system to complete the necessary distribution security analysis.

The Company will utilize the granular dispatch schedule information from the DOP to conduct distribution system security analysis of cleared DERA bids. This could be implemented by loading the schedule information from the DOP into the ADMS for modeling to identify any specific constraints caused by the day-ahead operation schedule of the DERA. Based on the completion of that analysis the Company would notify the DERA of any re-dispatch required to secure the distribution system. If the DERA market participation cannot complete sufficient re-dispatch of DER within the DERA to meet bid requirement given distribution constraints, then the DERA market participant would notify ISO-NE of the need for re-dispatch at the transmission level.

The sequencing and relative elegance of the communication solutions between the Company, the DERA, and ISO-NE to alleviate potential distribution constraints caused by DERA operation will continue to evolve over time, and the Company looks forward to future collaboration with the relevant stakeholders to continuously improve implementation. At the very least however, the Company will require, and accordingly proposes to develop a DOP that will deliver, the two functions described above -- (1) a way to communicate relevant system condition information to DERAs and (2) a way for DERAs to provide more granular scheduling information to the DERA.

The Company's proposal to develop a DOP to facilitate DERA market participation is consistent with the approach taken by the joint-utilities in New York, including the Niagara Mohawk Power Company d/b/a National Grid, to support the operational coordination components of the NYISO DER aggregation model. There is still some uncertainty in ISO-NE regarding if building and maintaining a DOP will be something that each of the individual distribution utilities does on their own, or if there will be a centralized New England-wide DOP. The New York approach as noted was to have portal development and maintenance be decentralized. Following the New York approach, the budget included in this filing assume that the Company would maintain its own DOP and reflects embedded cost efficiencies with New England and New York synergies.

Settlement System Upgrades

The Company, in its role as the meter reader, will also need to upgrade its retail and wholesale settlement systems to accommodate FERC O2222. As part of the AMI proposal included in this filing, the Company proposes various settlement system upgrades to properly support the functionalities and capabilities of the AMI meters. Settlement associated for FERC O2222 will leverage and build upon the AMI settlement system upgrades; however, additional upgrades would be required to facilitate settlement of the DERA products at scale, particularly because of the complications associated with the aggregation element. The budget for the incremental settlement system costs due to FERC O2222 only are included in this section.

Dual-Participation Distribution Management (DPDM) Study

The dispatch of aggregated and stand-alone DER for multiple use cases including wholesale market participation and distribution grid services requires new tools, processes, and skill sets to ensure that distribution system operators are able to support resource optimization while maintaining their obligation to provide safe and reliable service. In particular, the Company must be prepared to manage instances in which transmission use cases are not aligned with distribution use cases, such as when bulk transmission system (i.e., wholesale) conditions and the associated wholesale price signals are not coincident with local transmission and distribution system needs.

The Company proposes a joint-project with Eversource and Unitil to study, simulate, and test technologies and processes to address the needs and opportunities associated with coordinated dispatch of DER aggregations (DERA). Based on preliminary discussions between Eversource, National Grid and Unitil subject matter experts, the following represents a consistent three-phase approach to investigating and testing methods to optimize the integration of DER to provide transmission and distribution system grid services. The EDCs expect to collaborate for a common deliverable in Phase 1 and share data and outcomes throughout Phase 2 and Phase 3.

- **Phase 1 – Investigation**. Develop state-wide report on industry best practices for DER valuation and dispatch programs and methods
- **Phase 2 – Simulation**. Conduct computer simulation of proposed programs and methods
- **Phase 3 – Field Trial**. Field test with simulated constraints in zero risk environment

During the Phase 1 Investigation, the EDCs will work with external advisors to (a) assess state-of-the-art methodologies and technologies based on review of relevant literature and programs; (b) rank each approach based on pre-identified criteria and select the most attractive approaches for Massachusetts EDCs and; (c) develop a proposal and scope for Phase 2 simulations and the Phase 3 field trials. The funding requests outlined in each company's filing reflect the proposed respective contribution by the utility towards this phase.

Among other items, as part of Phase 1, the EDCs will explore contract mechanisms and associated DER compensation schemes that could be used to manage distributed resources and communicate with individual DER owners and aggregators regarding the status of grid congestion. This project will include consideration of opportunities to dispatch DER as distribution grid assets with an emphasis on flexibility and responsiveness and will incorporate concepts related to optimization of resources for multiple use cases, using tools such as direct control, price signals or operating bandwidth guidelines. The EDCs will look at international models such as the Grid Traffic Light, capacity bands, distribution locational marginal pricing (DLMP), and other models evaluated domestically and internationally on similar topics. The EDCs will also use Phase 1 to develop a more complete understanding of how or why certain models and technologies may be better or worse suited to serve the customers in Massachusetts. Lastly, Phase 1 will focus on the interaction between different utility systems, ISO-NE, customers and aggregators.

The Phase 2 Simulation and the Phase 3 Field Trial will be conducted independently by each EDC given the differences in each company's operating systems. The precise scope for these latter phases will be shaped by the findings in Phase 1. The EDCs will collaborate during Phase 1 to determine collectively which approaches should be further evaluated in Phase 2 and 3 to ensure that the companies are not conducting duplicative studies.

The scope for Phase 2 will be shaped by the findings in Phase 1. Phase 2 would involve a computer simulation to model the effectiveness of different proposed contract mechanisms and/or DER compensation schemes at shaping DER behavior relative to the grid in instances of perhaps competing cases utilizing modeling software.

The costs for a Phase 3 field study are not included in the four-year investment period at this time since these costs would occur in CY25 or later. The field study would be intended to test the effectiveness of the preferred identified method studied in Phase 2 by partnering with connected and operational DER on the distribution system. The Company acknowledges that the details for the Phase 3 field test are still uncertain at this time, and requests that a cost proposal for a Phase 3 field test could be discussed at a later date. Per the Department's DPU 20-69-A Order at p. 38, n. 17, the estimate for CY25 will be provided as soon as possible.

Other GMP Investments that would Help Support FERC O2222

The Company recognizes that several of the investment categories included elsewhere in this GMP would be critical to enabling the Company's role in facilitating and managing DERA participation in wholesale markets as a result of FERC O2222. For these investments there would be no incremental costs associated with FERC O2222 specifically, though we highlight their importance as capabilities to support FERC O2222.

Monitoring & Control. The continued investments in feeder monitors included in Section 3.2.1 enhance the ability of the Company to evaluate the impact of DER on the distribution system for both planning and operational purposes. This is critical to facilitate the DERA review and registration process and the operational coordination components of FERC O2222.

ADMS. The phased ADMS investments will enable the distribution control centers to more granularly manage, monitor, and control the distribution system, which will be critical for completing distribution security analysis of DERA wholesale operation.

Information Technology. Maintaining an easy to use and accurate DER registry will be an important capability to support both the DERA registration process and the operations coordination components of FERC O2222. The Company will utilize data stored in the Data Management Platform as described in Section 3.2.5 as a DER registry to support the operational needs for FERC O2222. All costs associated with storing and sharing data to support various business needs are embedded in the budget included in Section 3.2.5, and accordingly there would be no incremental investments due to FERC O2222 for this category.

Communications. The proposed communications investments in Section 3.2.5 include the infrastructure backbone to connect National Grid IT/OT infrastructure with field devices in the service territory. These infrastructure investments will enable the distributions control centers to fully utilize the suite of tools required to complete distribution security analysis of DERA operation in wholesale markets as a result of O2222.

DERMS. Short-term load forecasting (STLF) will be an important capability to support the distribution security analysis required for DERA operation. The Company will leverage the STLF capability described in Section 3.3.1 for FERC O2222, but does not propose incremental investments due to FERC O2222 for this category.

AMI. Full-scale deployment of AMI and the associated back-office work to modify and develop relevant systems and processes, will fundamentally expand the opportunity for customer DER to participate in value earning opportunities in the wholesale market by providing virtually all customers with a revenue quality interval meter that could be used for wholesale settlement.

<u>Benefits</u>

The Company cannot adequately support DERA wholesale market participation at scale given existing capabilities, personnel, and legacy systems. It is imperative that the Company obtain the necessary approvals to begin investments soon to ensure that we build out the required capabilities proactively ahead of when the DERA market models are implemented. The Company believes that the proposed investments would significantly improve the Company's ability to review and approve DERA registration applications, process and settle meter reads for DERA settlement accurately and in a timely manner, and operate a distribution system in which aggregations of DER are providing wholesale services at scale with sufficient monitoring and control to ensure safety and reliability. Thus, the FERC O2222 investments collectively are expected to provide the following qualitative benefits:

- Increased security of distribution system. The investments described in this section enable the Company to complete the necessary day-ahead and real-time distribution security analysis to evaluate the impact of DERA wholesale market operation on the safety and reliability of the distribution system. Absent such investments the Company would not have sufficient tools to properly manage the impact of DERA wholesale market operation at scale on the distribution system, which could otherwise result in unsafe conditions on our system and/or require forced outages.

- Reduced timeframe for DERA impact studies. Ensuring we have sufficient staff to support the distribution impact studies required to evaluate the impact of the proposed DERAs on the distribution system will expedite the Company's ability to facilitate the DERA registration process. In its role as the distribution utility, the Company will need to evaluate how the proposed operation of DERAs will impact the distribution system. This may result in the Company needing to complete additional distribution impact studies depending on the size of the DERA, the type of DER included, and the intended operation of the DER in the DERA relative to how they had been studied previously.

- Less frequent utility override of DERA bids. Implementation of the DOP will improve the speed and ease of data exchange between the DU and DERA, which will support timely review of the DERA planned operation on the distribution system security. This information sharing will result in less need for the utility to issue real-time overrides of the DERA, reducing the impact of the distribution utility on the real-time ISO-NE wholesale market operations. The DOP will also enable the Company to allow DERA customers to re-dispatch the specific DER within the DERA based on system constraints, rather than rejecting the DERA entirely.

- Accurate and timely settlement of DERA. Implementing the proper settlement system upgrades and hiring sufficient support in the meter data services department ensures that the Company is able to deliver on its role as the meter reader for DERAs. Absent such investments the Company would have no feasible or practicable way to support timely and accurate DERA settlement with ISO-NE, which would create a barrier to market access for DER.

- Increased DER adoption. Faster review and approval of DERAs, less frequent overrides, and more accurate and timely settlement processes, all work to improve the project economics and the customer experience for DER connecting to our distribution system. Collectively, these should help promote DER participation in wholesale markets as a viable and economic opportunity for customers to develop, interconnect, and monetize more DER. Additionally, increased DER adoption in the state supports Massachusetts's clean energy goals, including the Clean Energy and Climate Plan for 2030 and 2050 Decarbonization Roadmap.

- Reduced wholesale costs for all load customers. Participation of DER aggregations in competitive wholesale markets may result in a more economic resource mix in the future, which would benefit all load customers through reduced costs of wholesale market services.

<u>Progress and Schedule</u>

The schedule below outlines the timeline for completion of the various FERC O2222-related investments. Given the uncertainty with FERC O2222 timing in ISO-NE we assume that the new DERA market participation models would begin on January 1, 2024[32] and that customer participation in these new market products will increase over time. The Company recognizes that our capabilities to support FERC O2222 will continue to evolve over time, including after the ISO-NE implementation date for the associated new participation models. Our intent it to support opportunities for the DER in our service territory to receive compensation for the wholesale services they can provide as soon as possible, though we intend to be transparent with ISO-NE about our expected capabilities timeline as the stakeholder process progresses.

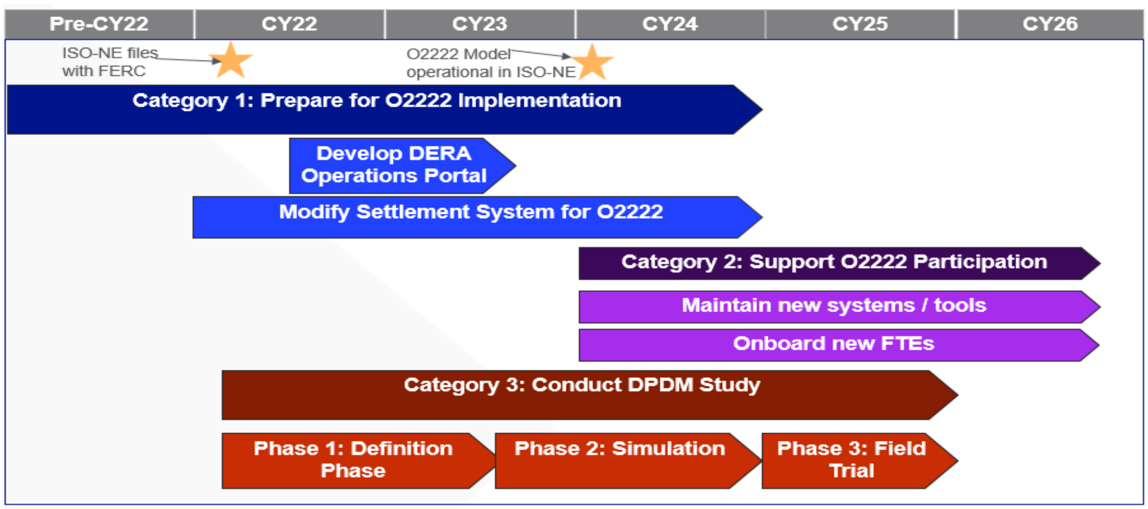

Figure 22: FERC 02222 Investment Schedule

<u>Major Tasks</u>

The major tasks to support FERC O2222 market participation can be categorized into three categories. Category 1 is the “Preparation” phase in which the Company would invest in the capabilities required to

[32] January 1, 2024 represents a fairly aggressive implementation timeline for ISO-NE and may be earlier than the eventual implementation date determined by FERC for ISO-NE. We use January 1, 2024 in this filing to convey the urgency of preparing for FERC O2222 soon. Delaying the implementation date by a year to 2025 would have no materials impacts on the type and scale of investments the Company would require to support FERC O2222.

support FERC O2222. In Category 1 the Company would develop and test the DER operations portal to support the distribution security analysis function of the operations control center. Category 1 would also include the necessary updates to the settlement system to accommodate settlement of DER aggregations.

Category 2 is the "Operational" phase in which the new DERA participation models would be operational in ISO-NE. Category 2 includes costs to the Company to maintain and manage the systems developed in Category 1. Notably, for Category 2, the Company would bring on new hires to manage the day-to-day tasks associated with registration, planning, review, metering and settlement, and operation of DERAs.

Category 3 is the "Study" phase in which the Company would complete the DPDM study to evaluate methods for managing DER participation in wholesale markets in instances in which wholesale market price signals and distribution system needs may not be aligned. The DPDM study would be completed via multiple sub-phases.

As the chart demonstrates, the Company will need to begin work as soon as possible to adequately prepare for O2222. It could be the case that the Company has some interim solutions to support FERC O2222 participation in the first year or so after the new market rules are operational in ISO-NE, but prior to Company's completion of the necessary system upgrades to fully support FERC O2222. Interim and/or manual solutions to accommodate early adopters of the new DERA participating models will not be feasible at scale and the Company needs to prepare prudently to accommodate DERA participation in the wholesale market at volume.

<u>Budget</u>

The table below presents the 4-year budget for FERC O2222, which includes investments in the underlying IT infrastructure, software, and data services. Included in the OPEX estimates are the associated labor costs and FTEs. The Company estimates investing $12.73 million through CY25.

Table 19: FERC O2222 – 4-Year Plan Budget

FERC O2222	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$2.09	$2.30	$1.67	TBD[33]	$6.05
OPEX ($M)	$0.67	$0.77	$2.09	$3.14	$6.68
Total ($M)	$2.76	$3.06	$3.76	$3.14	$12.73

3.3.3 New Metrics

The Company is proposing company-specific and statewide performance metrics for its newly-proposed investments, further detailed in Exhibit NG-GMP-5.

3.4. Demonstration Projects

3.4.1 Introduction

National Grid is proposing two demonstration projects to test new tools to facilitate the interconnection of DG in certain areas of the Company's electric distribution system that are approaching saturation.

Active Resource Integration ("ARI"): Explores the ability to interconnect up to 15 MW of actively managed large solar PV DG projects through a flexible interconnection service, avoiding the need for a new supply cable by limiting output from the solar PV DG projects during limited periods of high generation and low load. This technology and testing thereof will provide learnings in support of the DERMS investigation and subsequent implementation as the demonstration project progresses.

Local Export Power Control: Explores the use of a Power Control System to allow a behind-the-meter solar and storage project with net zero thermal impact to interconnect and operate without the need for costly system upgrades.

As explained below, the Company's proposed demonstration projects meet the Department's standard of review, which requires that the projects: (1) are consistent with applicable laws, policies, and

[33] The Company will make a supplemental filing as soon as possible with its proposed budged for CY2025 for these investments. D.P.U. 20-69-A at 38 n.17.

precedent; (2) are reasonable in size, scope, and scale in relation to the likely benefits to be achieved; (3) propose adequate performance metrics and evaluation plans; and (4) will result in minimal bill impacts to customers.[34]

3.4.2 Active Resource Integration

Introduction

In addition to National Grid's forward-looking integrated system planning and cost allocation proposals to support DG enablement through infrastructure reinforcement in D.P.U. 20-75 the Company believes there is an opportunity to increase DG interconnections to existing infrastructure on specific circuits through active management of DG. Under this active management scheme, the Company expects that, in certain scenarios, generation curtailment risk will be outweighed by other factors such as the reduced system upgrade cost realized by allowing DG to interconnect in excess of the current distribution grid hosting capacity constraints. Through this technology, the Company anticipates that greater amounts of additional DG energy can flow to the grid during non-grid constrained periods, while maintaining the safety and reliability of the grid. Research performed by the Electric Power Research Institute ("EPRI") suggests that in certain circumstances, active management may be an alternative least-cost solution to interconnecting DG by deferring system upgrades.[35]

While the Company expects that system upgrades will still be required to enable the majority of DG interconnections, ARI will serve as an important alternative in certain cases. It will also allow for greater energy production from DG per unit of system capacity, resulting in increased utilization of both existing and future system infrastructure. Several utilities have deployed pilots to actively manage DG and have demonstrated the feasibility of actively managing DG.[36] While this research offers promising results, a Company demonstration is required to gain deep experience in the Company's highly DG saturated service territory, collaborate with developers, and raise confidence that this ARI solution can deliver the expected benefits without risking the safety and reliability of the grid. These learnings will help to inform future Company DER management capability, enabled at scale via DERMS.

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[34] In NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178 (2017), the Department summarized the factors it considers when evaluating a proposed demonstration project. See D.P.U. 16-178, at 16. See also, Order Establishing Eversource's Revenue Requirement, D.P.U. 18-05 at 457.

[35] Maximizing DER Hosting and Grid Utilization Through Flexible Interconnection: Active Power Management, EPRI, December 2020

[36] Flexible Interconnection for Distributed Energy Resources, Emerging Practices of Early-Adopter Utilities, EPRI, December 2018

Today, the Company has limited ability to manage real-time production from DG to mitigate adverse impacts on the distribution system. To pursue this opportunity to increase DG enablement, National Grid is proposing to demonstrate the use of advanced DG control and active network management solutions to connect additional solar PV DG in its Risingdale area. The Risingdale area has reached its normal DG hosting capacity; further DG interconnection at this location would require a significant system upgrade to the 23 kV circuit. In this demonstration, rather than requiring solar PV DG project developers to pay for this upgrade, participating solar PV DG projects will be obligated to curtail their output when required by the Company based on real-time system conditions. This demonstration also will test developers' appetite for curtailment.

The development and implementation of the advanced DG control and active management solutions required for ARI will be used to inform the Company's DERMS preparations. The Company anticipates that this demonstration will benefit from some level of integration with other IT/OT systems proposed elsewhere in this filing including the proposed ASTLF and ADMS grid modernization investments as well as the Company's existing SCADA, EMS and Salesforce applications. For the purpose of proving out the ARI concept, these integrations may range from a comprehensive to a minimal integration approach, depending on what is required to demonstrate the pilot objectives at a reasonable cost.

In summary, this project will field test a new flexible interconnection option that could enable the Company to accelerate DER interconnections in certain cases. Actively managing DG is one of many use cases for DERMS and therefore ARI will also inform the Company's future implementation plan of an enterprise-wide DERMS. A successful ARI demonstration would benefit all customers by enabling the increased interconnection and integration of DG by interconnecting DG that may otherwise be uneconomical, therefore supporting the state's goal of increasing interconnection of DG to achieve 45% emissions reduction by 2030.

Demonstration Objectives and Consistency with Applicable Laws, Policies and Precedent

The ARI demonstration project aims to actively manage solar PV DG to enable accelerated DG interconnections where traditional system upgrades to increase hosting capacity may be more costly or require long construction times. Additionally, the incorporation of active management enables increased utilization of both existing and future grid assets. In addition to testing capabilities needed for a future enterprise-wide DERMS implementation as an enabling technology, a successful demonstration could lower initial interconnection costs, mitigate interconnection timeline constraints due to Company system construction upgrade time, and enable DG interconnection in excess of current hosting capacity constraints by managing dispatchable renewable DG through a flexible interconnection (e.g., non-firm capacity) service. In exchange, the DG customer will shoulder an acceptable level of generation curtailment risk and the cost of the monitoring and control solution required. This innovative interconnection solution supports and is consistent with the Department's grid modernization objectives of optimizing system performance and interconnecting and integrating DERs. The Company is looking to demonstrate this solution alongside other efforts by the Company such as its proposed integrated system planning analysis proposal in D.P.U. 20-75 to collectively support the state's emissions reduction goal by 2030 by enabling increased deployment of new clean energy projects.

Challenge and Opportunity of the Selected Demonstration Area

The Company's Risingdale substation is normally supplied by two 23kV underground cables (Lines #2316 & #2317) with a manual backup from Line #1 and #2 (see diagram below). These underground cables are direct buried from the Pleasant Street Substation (Eversource) to the Risingdale substation primarily along Route 102 and Route 7 between Lee and Great Barrington, a distance of approximately 9.1 miles long.

Due to the increasing amount of DG being interconnected to this area, the existing 23kV supply serving the area is approaching its ability to accommodate additional DG during system contingencies. As of April 2021, the combined total of existing and in-queue DG in this area is approximately 33 MW. The area has also seen about 40 MW of DG withdraw from the queue in this location, with developers citing the system upgrade costs as the reason for withdrawal. The summer emergency rating of the Line #2316 and #2317 cables is the operating limit in the event of an outage of one of the cables until the 23kV supply is rearranged through post-contingency switching. This 23 kV supply reconfiguration is currently conducted manually by area crews and can take several hours to complete. The expansion of DG in this area will soon be hampered by these cable limits.

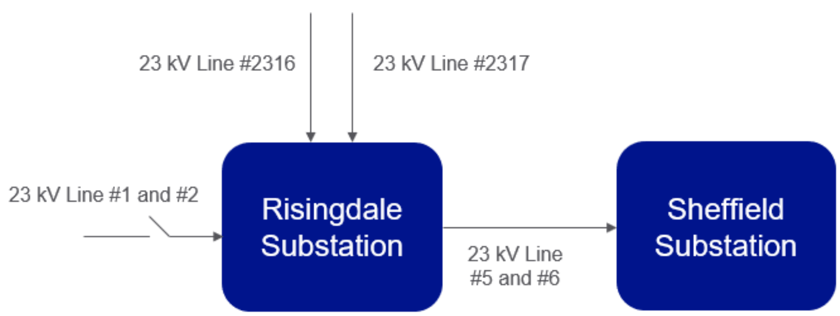

Figure 23: Simplified one-line diagram displaying 23 kV supply lines serving the Risingdale Area

Under business as usual, the Company would require any developers interconnecting above this limit in Risingdale to install a third 23kV supply cable along the same 9.1-mile manhole and duct system as the existing supply cables. The estimated cost for this third 23 kV supply cable is approximately $55 million. With the cost of the system upgrade required and the expected construction duration, the Risingdale substation constraint is an example where active management of DG presents the opportunity to defer system upgrades, while accelerating DG interconnection with existing infrastructure, if the required level of curtailment is acceptable to developers.

Using historical 8760 system load and forecasted PV generation data of the Risingdale and Sheffield area, the Company performed a preliminary 8760 curtailment analysis based on 2021 load forecasts under a 50-50 weather scenario to estimate the amount of hourly curtailment expected from existing and forecasted PV DG interconnected downstream of Lines #2316 and #2317. Based on a preliminary curtailment analysis modeled with PV under a flexible interconnection, the Company believes it can interconnect up to 15 MW of DG under a flexible interconnection service in this demonstration with the assumption that the level of generation curtailment risk identified is within acceptable financial tolerance of developers. Discussions with developers and other potential external stakeholders will further inform generation curtailment risk appetite in lieu of significant upfront system upgrades, as there is a tradeoff between operating all year to receive maximum state incentives and curtailing generation to reduce system modification costs.

Proposed Demonstration Plan

National Grid will work with participating developers through the DG interconnection process to consider and study how flexible interconnections can be used as an alternative to a traditional firm interconnection in certain situations. This may reduce end to end interconnection time by potentially reducing study durations and time for system modifications. ARI would not eliminate the need for typical interconnection studies and/or upgrades in overly saturated areas, however it would greatly assist in areas that are near hosting capacity under worst case conditions.

National Grid plans to study and interconnect DG sites up to 15MW through flexible interconnection contracts in the Risingdale area. The Company anticipates leveraging the learnings from its ongoing investigations to accelerate the process of flexible interconnections if they prove to be a viable interconnection option to the affected parties. Although the Company does not foresee significant challenges to gather developer interest in the Risingdale area based on the history of the interconnection queue, National Grid may consider another similar location if it cannot identify enough developer participants in the Risingdale area for this demonstration.

The Company will work with the DG community to develop the customer-facing aspects of offering a flexible interconnection option. This effort will include investigating how to fairly allocate the necessary curtailment to mitigate real-time system constraints across multiple DG sites under a flexible interconnection service. The Company will solicit input on this and other decisions both from participating developers and the broader DG community to understand what new contractual terms and agreements may be required between the Company and the interconnecting customer.

To optimize system utilization and maintain grid security through the ARI demonstration, the Company will develop, implement, and test new DG monitoring and control and active management solutions further described in Key Equipment Section below that will allow the Company to autonomously manage multiple customer-owned DG on a specific circuit to mitigate real-time system constraints. Operating the demonstration project will provide crucial learnings regarding the ability of dispatchable renewable DG to comply with curtailment signals from the Company within acceptable performance parameters. The Company will also assess fail-safe provisions in case of a failure of the management scheme to ensure system reliability and safety is upheld.

Key Equipment Needed

A list of solution requirements was developed by the Company. Major devices and systems include a secure communication gateway located at DG sites to facilitate dispatch instructions with proper fail-safe features and the curtailment management system which contains the curtailment rules and calculated curtailment dispatches to each DG in real-time with the necessary measurement and verification to confirm compliance. The Company is currently testing a feature-limited gateway at two Company-owned solar sites to validate the feasibility of communicating curtailment requests directly with a DG site through the Company's SCADA network. The Company also expects that the curtailment management system represents a subset of capabilities available in commercially available DERMS solutions.

Some IT/OT integrations that will facilitate the monitoring (i.e., grid visibility), command and control required to manage DG within real-time system constraints include integration with the Company's EMS/ADMS, DG interconnection database ("DER Registration"), SCADA and PCC recloser equipment for DG monitoring and control, and the proposed granular short-term load forecasting under National Grid's ASTLF investment.

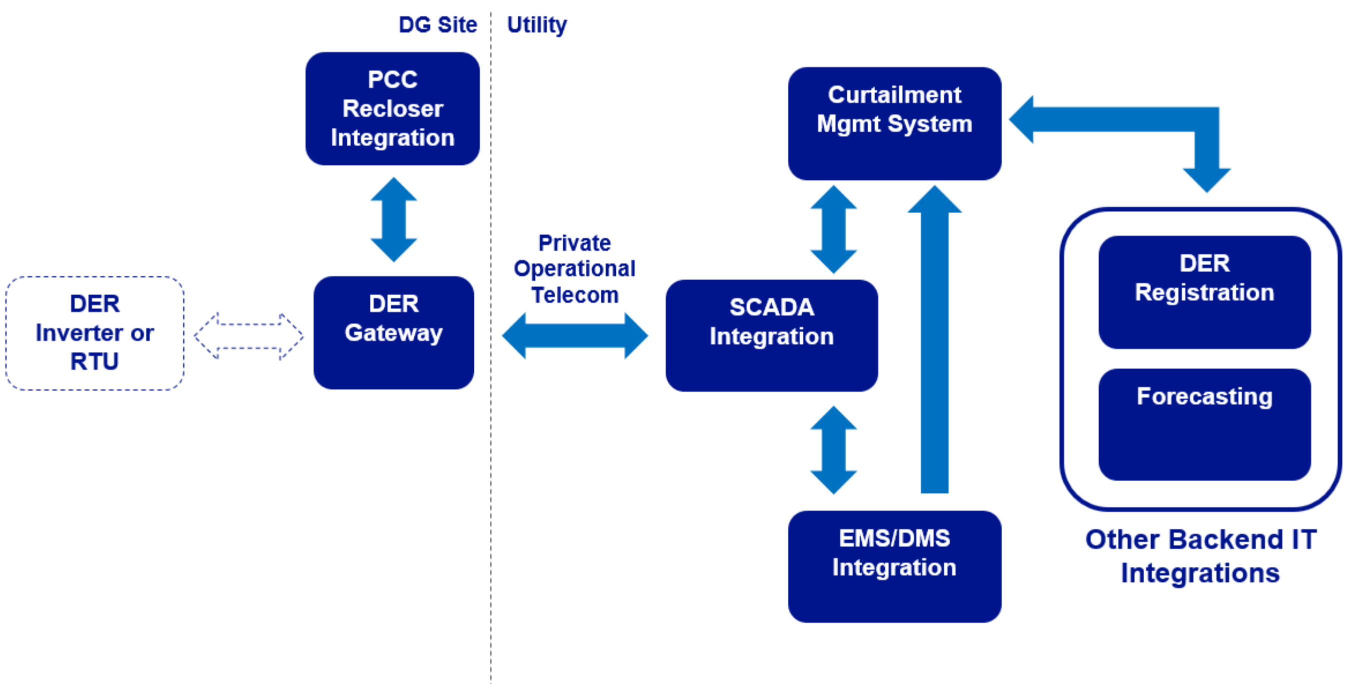

Figure 14: Preliminary ARI solution architecture

Proposed Project Schedule

The Company anticipates completing the following activities prior to demonstration project approval:

- **Operational Requirements Test:** The Company is currently developing and testing some foundational technical and operational capabilities of flexible interconnections, including the hardware and software to curtail DG, as well as integrating communications and control with the Company's SCADA and control center. The Company will leverage advanced inverters and site controllers that have already been deployed at Company-owned solar sites in Massachusetts and build out additional supporting infrastructure to deploy and test advanced remote system controls. The Company will autonomously curtail these sites based on simulated system conditions, which allows a limited way to demonstrate the feasibility of integrating resources with a flexible interconnection. This test system will only be feasible in the controlled environment of Company-owned sites, as it is not capable of scaling to support customer-owned DG. This test is expected to be operational by the end of 2021. The demonstration project will expand from these learnings to contract, interconnect, and coordinate multiple, customer-owned DG behind a constraint.
- **Flexible Interconnection Impact Modeling:** The Company has commissioned the Electric Power Research Institute ("EPRI") to perform a technical and economic feasibility assessment of flexible curtailment on representative feeders to be completed by mid-2022. This assessment will determine the constrained areas on the Company's distribution system that potentially would be best suited for this solution and will DG developer economics under a flexible interconnection contract. The Company is also working with EPRI to develop a method for assessing the anticipated location-specific hourly curtailment when studying a specific DG site location for flexible interconnection.
- **Solicit Developer Community Interest and Input:** The Company plans to host listening sessions to engage with the developer community to solicit input on program design and implementation. The Company is interested in exploring topics that include how curtailment risk will be assessed and evaluated by developers and their financiers, the impact flexible interconnection would have on system design, and how developers may choose to leverage on-site storage to mitigate the impact of curtailment on project revenues.

The Company propose to complete the following activities:

- Technology Deployment Activities:
    - Develop or procure Control Technology: As detailed above, while the Company may seek to build strategic assets, the Company may choose to procure control technology elements similar to that of commercially available DERMS solutions to realize the goals of this program. The Company will seek to leverage findings from its New York affiliate's ARI pilot to inform this process. This will occur approximately one year following approval of this demonstration project.
    - Deploy and Integrate Control Technology: In line with DG development and interconnection of flexible DG.
    - Control System End to End Testing: 6 months following deployment

- Measurement and Verification: Review and assess the performance of demonstration DG sites to respond to real-time and dynamic curtailment requests and the back-end curtailment management system to accurately evaluate and determine the necessary curtailment needs of the distribution circuits of the Risingdale area.

- Developer Facing Activities:
  - Solicit Developer Applications to Demonstration Project: As noted above, this demonstration project may host up to 15 MW of additional DG capacity. The Company would seek to enroll sufficient capacity, limiting participation to one project per developer to ensure maximum learnings.
  - Perform Site-Specific DG Curtailment Analysis: For each site in the demonstration project, perform curtailment analysis as part of the interconnection application process.
  - Develop Curtailment Contract: Working with participating developers as well as the broader developer community, propose language to govern flexible interconnection expectations and requirements, subject to Department approval as appropriate.
  - Interconnect Flexible DG: Approximately two years following approval of this demonstration project, contingent on DG developer interest and interconnection application.
  - Observe Operation of Flexible DG: Two years following interconnection.

<u>Reasonableness of Size, Scope and Scale of the Demonstration Project</u>

The size, scope, and scale of this project is reasonable in comparison to the likely benefits to be achieved in the future for interconnecting DG projects. This will be accomplished by interconnecting several DG projects, aggregating up to 15MW behind a single thermal constraint, at a total cost over four years of approximately $6 million. The technology and benefits are scalable for other DER interconnections such as wind and energy storage. The expected benefits would include lower interconnection costs and reduced interconnection timeline constraints due to deferred system modifications. This technology could enable additional DG interconnections in areas currently experiencing thermal hosting capacity constraints and allow for greater energy production per unit of system capacity for both current and future infrastructure. A successful ARI demonstration would benefit all customers by enabling the increased interconnection and integration of DG in support of the Commonwealth's climate goals.

<u>Scalability</u>

For this demonstration project, the Company intends to validate its ability to offer a flexible interconnection alternative for solar PV resources. The demonstration project should provide learnings to inform how the Company can intelligently manage flexible interconnections in a way that minimizes the economic impact from curtailment for participating DG projects while maintaining the reliability and safety of the distribution system subject to a specific grid constraint.

The intent is that the findings from this project should inform considerations of an expanded offering of flexible interconnection as an alternative to a traditional "firm" interconnection. As shown below in Figure 3, the ARI concept is most applicable in areas where the loss of revenue due to curtailment does not exceed the cost of a system upgrade. Therefore, ARI would most likely would not be able to alleviate concerns in heavily saturated areas with significant, concentrated amounts of new applications due to the increased amount of curtailment that would be required. However, at scale, this project could incrementally enable additional interconnections across the territory, enabling increased volume of DG interconnections in the aggregate. Wide-scale deployment of flexible interconnections could accelerate the pace of the DER interconnection and integration across the MECO service territory by offering an economic alternative for future DER interconnection requests in constrained locations. While this demonstration would be limited to a single type of DER (solar PV or solar PV with storage) and a single type of constraint (thermal), the aspiration would be for the learnings from developing interconnection agreements and deploying active management technology to inform applicability to other types of DER, use cases (e.g., contingency support, peak loading) and to address constraints at other voltage levels (e.g., sub-transmission, transmission) via DERMS. Thus, at scale, ARI could enable the Company to offer an alternative interconnection option in the future for other DER types based on the relevant system constraints in the interconnection location.

This demonstration project will also provide valuable learnings to inform the continued development of the Company's plans for grid modernization infrastructure and digital solutions, especially DERMS. A key future integration need that the Company will consider in this demonstration is the required interface between a DERMS and the Company's ADMS that may indicate the eventual need for optimal power flow capabilities to inform near-term and real-time system constraints. The Company also sees ASTLF as an essential component in supporting these active management solutions and to provide operational awareness so that the Company can optimally plan its system operations ahead of time to efficiently mitigate security violations such as excessive generation backfeed.

Flexible interconnections will not be a substitute for standard unconstrained, firm interconnections in all instances, but rather provides an alternative option to support interconnection in certain specific situations. It is also not a substitute for the build-out of distribution system infrastructure.

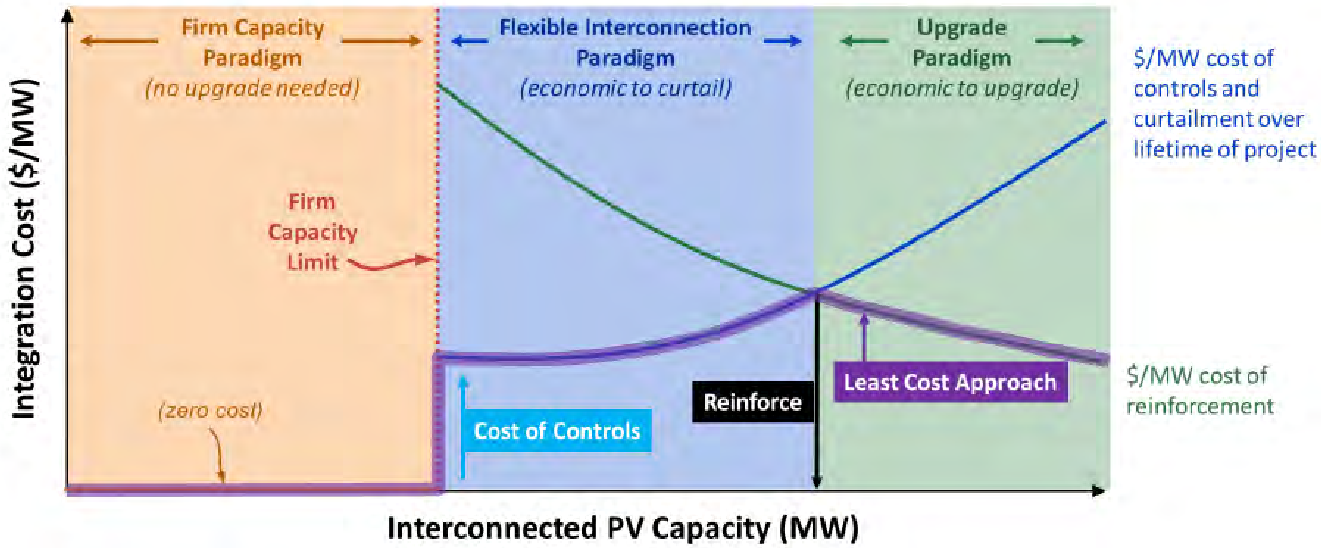

Figure 25: Illustration of three least-cost solar PV integration approaches by interconnected PV capacity[37]

The EDCs have agreed to collaborate and work together to align in determining increased value created through monitoring, controlling and utilizing non-utility owned DER assets in a variety of different use cases beyond those in operation today (i.e., DG optimization). Together, the EDCs will explore the value and compensation mechanisms to the DER owners that can be implemented across the state for these incremental DER managed use cases. National Grid and the other EDCs intend to leverage the collective knowledge and experience from DER integration demonstrations like ARI as an input to this collaborative effort.

<u>Performance Metrics and Evaluation Plan</u>

The results of the demonstration will be evaluated by tracking the following metrics:

[37] EPRI. The Value of Flexible Interconnection for Solar Photovoltaics Enabled by DERMS – Detailed Techno-Economic Analysis in New York State, Final Report, March 2021

ARI Demonstration Goals	KPIs
System Benefits	• Aggregate DG MW nameplate capacity that can be accommodated through a flexible interconnection option without a system upgrade for a third 23 kV supply line serving Risingdale, with and without ARI • Annual forecasted curtailment vs. estimated actual annual curtailment • Number of days and hours of curtailment based on Company curtailment requests
Participant Benefits	• Number of DG participants with an executed contract through a flexible interconnection • Estimated total avoided developer system upgrade costs for all DG projects connecting through a flexible interconnection • Flexible DG curtailment performance in response to Company curtailment requests • Estimated average incremental cost borne by developer to implement ARI on a DG project

Budget

Table 20 presents the 4-year budget for the ARI demonstration project. The Company estimates investing approximately $6.20 million through CY 2025.

Table 20: ARI Demo Project– 4-Year Plan Budget

Active Resource Integration	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	**CY 2023**	**CY 2024**	**CY 2025**	**CY22-25**
CAPEX ($M)	$2.03	$1.39	$0	$0	$3.43
OPEX ($M)	$0.22	$0.72	$0.90	$0.93	$2.78
Total ($M)	$2.26	$2.11	$0.90	$0.93	$6.20

Bill Impacts

The Company anticipates that the proposed costs for this demonstration project will have minimal bill impacts on the Company's customers over the four years of this demonstration project.

3.4.3 Local Export Power Control

Introduction

In addition to the front-of-the-meter projects addressed in the previous section, rising interconnection costs are also impacting customers installing DG projects behind-the-meter. Due to rules and regulations surrounding these service connections, many projects require a full distribution system impact study that could result in significant costs and timelines, which could be challenging for DER projects. An example of this may be a school or commercial building looking to add solar and storage. Typically, installations like this are location-specific and tied to a facility, making it infeasible for them to change the location. Also, the size and scale make the system economics sensitive to interconnection costs. Today, the solution to avoiding full system impact studies requires the BTM DER to have zero net thermal impact to the grid with protection that would operate and trip the DER should any export try to occur. This can become burdensome on small to medium commercial customers due to cost for additional engineering as well as potential loss of production should the site go over the export restrictions momentarily. These issues can derail project momentum and end up voiding the viability of smaller projects.

National Grid proposes an investigation of DER tested to UL 1741 CRD[38] for Power Control Systems (PCS).[39] Under this scheme, a behind the meter ("BTM") customer would utilize tested technology in order to maintain a net-export limit at the site. In other words, this would leverage on-site technology to use a customer-owned storage system to charge when their solar generation is more significant than on-site load. If the storage system reaches its capacity, the storage system will ramp down site generation to ensure that the storage system would not export back onto the distribution system. In order to pursue this opportunity to increase DER enablement, National Grid is proposing to demonstrate the use of a customer control system at a behind the meter (BTM)[40] solar inverter customer paired with or without battery energy storage to manage the associated output to keep below the net zero thermal

[38] Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources, Certification Requirement Decision – Subject for Power Control Systems.

[39] As noted in the February 26, 2020 cover letter to the proposed consensus revisions to the Standards for Interconnection of Distributed Generation tariff to address the interconnection of energy storage systems filed in D.P.U. 19-55, the Joint Stakeholders (as defined in the letter) spent considerable time attempting to identify specific power control technologies that could, if deployed, establish an export capacity that would be considered limited for certain specific purposes for the EDCs to consider, as appropriate, when performing reviews and/or engineering analyses. Although the Joint Stakeholders were unable to arrive at complete consensus, they retained the concepts of export capacity and export-limiting technologies in the proposed consensus language. This demonstration project proposes to test such a power control technology, as a follow up to the Joint Stakeholders' attempts to reach consensus on this topic.

[40] Behind the meter refers to a DER project that is connected with an onsite customer load. This does not include DER that is paired with battery energy storage but not connected with an onsite customer load.

impact protection trip threshold. National Grid proposes to test this solution in the Barre-Athol region, an area where cost and timeline for system upgrades due to area saturation makes smaller BTM projects economically infeasible. In this demonstration the DER project will be obligated to maintain a net-zero impact to the system. This will be accomplished via a battery energy storage system ("BESS") creating additional load as well as the PCS providing the net zero thermal impact limitations. A backup export relay and monitoring system will be installed for validation of parameters.

Demonstration Project Objectives, and Consistency with Applicable Laws, Policies and Precedent

The BTM CRD demonstration project will be used to explore the capabilities of customer-owned PCS or local plant master controllers to performing functions that are typically done by utility grade relays. This project could also provide a more efficient interconnection design by removing secondary relay protection requirements. A successful demonstration would result in significantly lower interconnection costs, expedited timelines, and increased interconnections in congested areas for appropriate BTM projects. The risk to the distribution system associated with this demonstration project would be monitored via a validation system that verifies the customer's net zero thermal impact on site. This demonstration project is consistent with and promotes the Department's objective to interconnect and integrate more distributed energy resources, and with the Commonwealth's goal of 45% emissions reduction by 2030 that could be achieved through 7 GW of new clean energy projects. As part of this demonstration, National Grid will work with the participating developer to follow the expedited interconnection process because the DG project would have net-zero thermal impact and therefore would not require a full distribution impact study. In summary, through this demonstration project the Company will investigate the ability to enable BTM net-zero impact projects in areas of high DG saturation to connect faster and more cost-effectively.

In order to test the technology, the Company will work with a BTM customer to verify that the technology meets all applicable UL 1741 CRD for PCS testing standards, validate that the PCS is being installed in accordance with all National Grid standards, witness the functionality of the equipment onsite under a variety of constraints and monitor the site to make sure true net-zero thermal impact is maintained. The Company will also perform studies to determine the applicability of this technology to stand-alone interconnection projects.

Proposed Demonstration Plan

The Company will work with the developer to perform the following tasks:

- Develop methodology to expedite projects that meet requirements
- Work with Customer to interconnect DG projects to the Company's local distribution system
- Validate PCS is performing as expected
- Use lessons learned to expand program to other DER interconnections

The demonstration will evaluate multiple testing scenarios in order to verify that the project technology is operating as expected such as time of day constraints, different export constraints, PV in service, and/or BESS in service.

Reasonableness of Size, Scope and Scale of the Demonstration Project

The modest size, scope, and scale of this demonstration project is reasonable in comparison to the likely benefits to be achieved in the future for net-zero thermal impact BTM DG projects if the technology proves out. This will be accomplished by testing at a single customer on a single feeder at a total cost over four years of approximately $170,000. The technology and benefits are scalable for other DER interconnections. The expected benefits would include significantly lower interconnection costs, expedited interconnection timelines, reduced loss of production from export relays, and the ability to connect in electrically congested areas. In the aggregate, this would expedite interconnecting additional DG/DER to the Company's electric power system, particularly in densely populated areas and for small commercial and industrial customers.

Scalability

The Company anticipates that validation of UL 1741 CRD for PCS could significantly benefit future BTM interconnections to the grid. By initially studying a complex case of PV + Storage behind a net load, National Grid believes a PCS can be implemented in a multitude of use cases. Examples of where this type of technology may become widespread are:

- Solar utilized to offset renovation/upgrade costs
- Storage utilized to smooth the output profile of sites
- EV charging stations that utilize storage

Developers who choose to pursue this type of an interconnection for a BTM project would avoid the significant timelines and cost associated with the standard interconnection track, which includes full distribution system impact study and potential system modifications. As such, this project could potentially enable more BTM interconnections. Of particular benefit would be enablement of connections in portions of the service territory that do not have open land available for large solar farms. For example, this would enable interconnections in the Company's heavily populated areas, such as the Company's northern territory, where customers such as small commercial/industrial customers have no choice but to consider rooftop or other BTM connections due to the lack of available land to site DG projects. Developing more tools to allow for developers to affordably and efficiently connect to the Grid is a key goal for National Grid and testing and proving this type of technology could lead to future deployment of variations such as customer owned BESS to offset stand-alone DER requirements.

Performance Metrics and Evaluation Plan

The results of the demonstration will be evaluated by tracking the following metrics:

BTM CRD Demonstration Goals	KPIs
System Benefits	• Ability to progress applicable BTM projects through the interconnection process more quickly • Net-zero thermal impact of applicable BTM projects on the grid. • Lessons to scale to other types of DER projects
Participant Benefits	• Lowered interconnection cost by accounting for negligible impacts of net zero thermal impact DG projects and avoiding potential system modifications such as a non-export relay • Reduced timeline for applicable BTM projects by placing them into the expedited interconnection process instead of the standard interconnection process • Reduced loss of production by curtailing a project site instead of tripping the system offline.

Budget

Table 21 presents the 4-year budget for the Local Export Power Control demonstration project. The Company estimates investing approximately $170,000 through CY 2025.

Table 21: Local Export Power Control Demo Project – 4-Year Plan

Local Export Power Control	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$-	$0.02	$-	$-	$0.02
OPEX ($M)	$-	$0.13	$0.01	$0.02	$0.15
Total ($M)	$-	$0.15	$0.01	$0.02	$0.17

Bill Impacts

The Company anticipates that the proposed costs of this demonstration project will result in minimal bill impacts to the Company's customers over the four years of this demonstration project.

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3.5. Measurement, Verification & Support

3.5.1 M&V

In D.P.U. 15-120, at 204, the Department determined that it is appropriate to establish a formal evaluation process, including an evaluation plan and evaluation studies, for the Companies' preauthorized grid modernization plan investments. The evaluation plan will provide, to the extent possible, a uniform statewide approach and standards to study the deployment of the preauthorized grid modernization investments to ensure that benefits are both maximized and achieved with greater certainty, and that future investments are more effective.

As part of the evaluation process, the Companies, in consultation with DOER, selected Guidehouse (formerly Navigant Consulting) as the evaluation consultant to conduct studies on appropriate topics related to the deployment of the preauthorized investments. The Company has included estimated costs for the ordered Evaluation Plan.

Budget

Table 22 presents the 4-year budget for Measurement & Verification. The Company estimates investing approximately $1.66 million through CY 2025.

Table 22: M&V – 4-Year Plan

M&V	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$0.0	$0.0	$0.0	$0.0	**$0.0**
OPEX ($M)	$0.40	$0.41	$0.42	$0.43	**$0.43**
Total ($M)	$0.40	$0.41	$0.42	$0.43	**$1.66**

3.5.2 Project Management

The Company established a new organization in August 2018, the Grid Modernization Execution organization, to drive the delivery of the grid modernization investment areas approved in the Order. This organization performs the functions of a project management office and manages the overall delivery of services which includes: portfolio management and reporting, business process design and requirements definition, solution architecture, requirements management, change management, testing management, training and transfer planning and coordination, deployment operations, vendor technical implementation coordination and performance monitoring and reporting. The costs represented here are for a subset of incremental employee costs or third-party services for delivering the grid modernization portfolio.

Budget

Table 23 presents the 4-year budget for Project Management. The Company estimates investing approximately $1.71 million through CY 2025.

Table 23: Project Management – 4-Year Plan

Project Management	Yr 1	Yr 2	Yr 3	Yr 4	Total
	CY 2022	CY 2023	CY 2024	CY 2025	CY22-25
CAPEX ($M)	$0.0	$0.0	$0.0	$0.0	**$0.0**
OPEX ($M)	$0.65	$0.67	$0.69	$0.70	**$2.71**
Total ($M)	**$0.65**	**$0.67**	**$0.69**	**$0.70**	**$1.71**

3.5.3 Incremental FTEs

In order to determine the needs for training, ongoing support and maintenance, and incremental resources required by grid modernization, the Company considered the needs within each of the components of its GMP and leveraged experience during the delivery of the initial plan period. These provided the basis of the analysis and shaped recommendations about the type and quantity of additional incremental resources necessary for years CY22 to CY25.

The results of the Company's high-level analysis indicated the need for training resources to both develop and deliver technical and process content, in order to operate successfully new grid modernization technologies and systems and to enable new ways of working in this modernized environment. Personnel in support and maintenance roles will fulfil a variety of needs in the GMP including: network planning to determine where smart devices are most beneficial; engineering design and support services; customer outreach; and program management.

Table 24: Incremental FTEs by Category

Grid Modernization Investments		
Category	**Subcategory**	**Total # of additional FTE**
Monitoring & Control	Feeder Monitors	0
VVO	VVO/ CVR	10
ADA	ADA/ FLISR	9
ADMS	ADMS Core Functionality Mobile Dispatch RTU Separation Distribution PI Historian GIS Data Enhancements	7
Information Technology	Enterprise Integration Platform Data Management Cyber Services	2
Communications	Communication & Networking INOC	14
Measurement, Verification & Support	M&V Project Management	0
DERMS	DERMS Investigation DERMS Implementation Advanced S-T Load Forecasting	3
Demonstration Projects	Active Resource Integration Local Export Power Control	3
FERC O2222	Settlement System DERA Operations Portal	12
Total		**60**

4. Costs and Benefits for Grid Modernization

This section presents a comprehensive BCA for the proposed GMP, consistent with the Department's grid modernization business case filing requirements set forth in the D.P.U. 12-76-C Order. The Order states that "the business case will serve as the vehicle by which the Department and other parties will evaluate whether the benefits, both quantified and unquantified, justify the costs of the proposed STIP investments". The Company's BCA shows that the benefits justify the costs of the proposed grid-facing grid modernization investments. The

BCA for the Company's AMI proposal is addressed separately in the testimony and exhibits of the Company's AMI Panel.

4.1. Approach

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

- **Counterfactual Treatment**: Future grid modernization investments are compared to a counterfactual or reference case (i.e., no new grid modernization investment) in a consistent and comprehensive manner.
- **Energy Policy Goals**: To the extent possible, the BCA accounts for the Commonwealth's various policy goals, in particular, the BCA assumptions are consistent with the Resilient Massachusetts Act's 80x50 Goal and the more recent Climate Act's net-zero by 2050 goal.[41]
- **Symmetry**: The BCA includes all quantifiable costs and benefits for each GMP investment including capitalized overhead costs, as well as non-capitalized operations and maintenance ("O&M") costs that are integral to implementation of the proposed GMP and achievement of its benefits.
- **Forward Looking**: The D.P.U. 12-76-C Order states that "the company must identify any incremental STIP capital investments for which it plans to seek cost recovery in a later capital expenditure tracker proceeding." Therefore, the BCA captures costs and benefits of the proposed GMP using a projected ten-year investment of the solutions over a 20-year period, disregarding sunk costs and benefits.

For each GMP investment category, the Company attempted to monetize all costs and benefits to the extent possible utilizing vendor quotes, estimates from in-state demonstration projects, data from relevant case studies in other jurisdictions, or modeling. To ensure the BCA covered all the potential benefits and costs of grid modernization investments, the Company surveyed several other utility filings for AMI and grid modernization plans to understand the scope of the BCA (i.e., which grid modernization functionalities and investments were included) as well as the type of cost-effectiveness test that was being applied (e.g., least-cost/best fit, societal cost test). This survey also provided a benchmark for benefit and cost categories to be included in the Company's grid modernization BCA. The results of the survey indicated that the scope and breadth of the Company's BCA for Massachusetts is more thorough than the other filings in the survey as a result of the Company having applied D.P.U. 12-76-C.

Due to the significant customer benefits enabled by AMI, two separate, but consistent, quantitative BCA models were developed: grid-facing GMP BCA model and an incremental customer-facing AMI BCA model. The GMP BCA model assumptions and results are described in detail in this section and the AMI BCA is described in detail in the AMI Panel Testimony. The following key assumptions are used in the base case BCA for both GMP and AMI:

- Plan Investment Period = 10 years
- Financial Analysis Period = 20 years
- Nominal Discount Rate = 7.56% (After-Tax WACC)
- Escalation (Inflation) Rate = 2.671%

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[41] n Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, Chapter 8 of the Acts of 2021.

The detailed BCA assumptions and results presented in this section are focused on the grid-facing GMP BCA model only.

4.1.1 Building a Benefit-Cost Analysis

To evaluate the cost effectiveness of the proposed grid modernization portfolio of investments, the Company developed a quantitative BCA based on the Department's grid modernization objectives. The GMP BCA is intended to compare the relative costs and benefits of GMP solution investments anticipated through calendar year (CY) 2031 compared to traditional solutions (i.e., reference case). The financial analysis uses an NPV calculation over a twenty-year period (i.e., through CY 2041). The assessment compares distribution system plans that utilize technologies that provide integrated modern grid capabilities (i.e., "Grid Modernization Case") versus a plan that is limited to traditional infrastructure (i.e., "Reference Case"). In addition to providing directional information in terms of how the quantifiable benefits and costs compare to a Reference Case, the GMP BCA also provides the Company and external stakeholders with a better understanding of the key factors that impact the quantifiable benefits and costs and allows all parties to focus future efforts on better understanding and influencing those factors in a positive way.

The GMP BCA is based on the Company's best available knowledge at this time and may be updated if new benefit or cost information is developed.

4.1.2 Benefit Impacts

For the purposes of estimating power system (e.g., avoided utility O&M and capital costs), customer, and societal benefits, the Company developed several benefit impact areas, which are either quantified or qualified in the BCA. Each quantified benefit impact area has been defined and categorized based on the GMP benefit categories below.

Avoided O&M Costs

- OPEX Labor Efficiency: Improvements in operational efficiency, such as reducing labor hours to perform normal (blue sky) or storm-related operational tasks due to digitization (e.g., Mobile Dispatch)

Avoided Capital Costs

- Avoided Legacy CAPEX Investments: Avoiding "legacy" CAPEX system investments, such as DS0 to T1 network conversion costs, due to the proposed grid modernization investments.

Customer Benefits

- Reduced Customer Energy Use: Reductions in electrical energy used by a customer, which can be a result of utility action, such as operating distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption from customer appliances (i.e., VVO/CVR).

- Reduced System Capacity Requirements: Reductions in system capacity requirements in either the generation, transmission or distribution systems, which can be a result of utility action (i.e., VVO/CVR).
- Reduced Outage Restoration Time:[42] Reductions in customer outage durations due to the ability of the system operator and control system to quickly locate and isolate a fault and restore power (e.g., ADA/FLISR) rather than waiting for field crews to locate, isolate, and restore power.

Societal Benefits

- Reduced Customer Energy Use: Reductions in non-embedded central power plant emissions of carbon dioxide (CO_2) resulting from reductions in electrical energy used by a customer, which can be a result of utility action (i.e., VVO/CVR).[43]

Additional qualitative benefit impact areas were identified and categorized based on the GMP benefit categories in Table 25. Each of the qualitative benefits and their drivers are described in *Section 4.3: Qualitative Assessment*. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

[42] This benefit is based on sustained outages (as opposed to momentary outages), which are defined as lasting longer than five minutes.

[43] The Commonwealth's new climate legislation signed by Governor Baker on March 26, 2021, requires that Energy Efficiency Program Administrators incorporate the social value of carbon in the BCA models used in the Total Resource Cost Test when evaluating the cost-effectiveness of energy efficiency measures. The GMP also included the societal cost of carbon for consistency with the Energy Efficiency Program's BCA.

Table 25: Grid Modernization Qualified Benefits and Drivers

GMP Benefit Category	Benefit Impact Area	Benefit Driver
Avoided O&M Costs	OPEX Labor Efficiency	Communications Network Refresh
	Avoided Legacy OPEX Investments	Flexible Communications Network
	Improved Long-Term Forecasting for Planning	Granular Data
	Improved Operational Efficiency	Granular Data
		Mobile Dispatch
		Protection Coordination
		Accurate Short-Term Load Forecasts
Avoided Capital Costs	Avoided Distribution-System Infrastructure	Load Optimization
Customer Benefits – Empowerment	Improved Customer Choice and Control	Customer Information Sharing
	Improved DER Experience	DER Integration
		Accurate Short-Term Load Forecasts
	More Equitable Benefit Allocation	Granular Data
Customer Benefits – Energy Savings	Reduced DG Curtailment	Renewable DG Optimization
	Reduced Customer Energy Use	Network Model Integration
	Reduced Customer Energy Costs	Enhanced Load Shift
	Improved Short-Term Forecasting for Operations	Granular Data
	Reduced System Loss	Local Generation Sources
		Optimized Reactive Power Control
Customer Benefits – Reliability Improvements	Reduced Customer Outages	Granular Data
		Communications Network Refresh
	Improved Storm Recovery	Granular Data and Distributed Automation
	Improved Resilience	Situational Awareness and Distributed Automation
	Improved Customer Satisfaction	Outage Notification
		Better Access to Markets
	Grid Modernization Performance Benefits	Reliable Private Communications Network
	Economic Development Benefits due to GMP Investment	GMP Investments
Societal Benefits	Economic and Environmental Benefits	DER Integration
	Reduced Damage from Wide-scale Blackouts	Situational Awareness
	Improved Grid Stability and Data Protection	Cyber Security

4.2. Quantitative Benefit-Cost Analysis

The grid-facing GMP BCA uses a Societal Cost Test[44] to identify where grid modernization solutions contribute to specific cost or benefit categories. Where possible, these benefits are quantified. In cases where benefits cannot be quantified due either to lack of data or lack of an accepted method, the Company conducted a qualitative analysis of the benefits. The qualitative explanation of benefits is provided in *Section 4.3: Qualitative Assessment*.

Many of the functionalities and benefits available through the GMP occur when multiple solutions interact. This increases the challenge for stakeholders and decision-makers who would like to consider GMP solutions on an individual solution basis. In general, the overall GMP benefit-cost ratio (BCR) is presented in terms of the full portfolio of inter-related investments, and therefore the GMP BCA quantifies benefits based on assuming that the solutions interact with each other as opposed to stand-alone or siloed investments.

4.2.1 Summary BCA Results

A summary of the quantitative BCA results is shown in Figure 26. The blue bar represents the costs of deploying the GMP portfolio, and the orange bar represents the quantified benefits of the portfolio. Both costs and benefits are presented on a 20-year NPV basis.

[44] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, National Energy Screening Project, August 2020 (https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/)

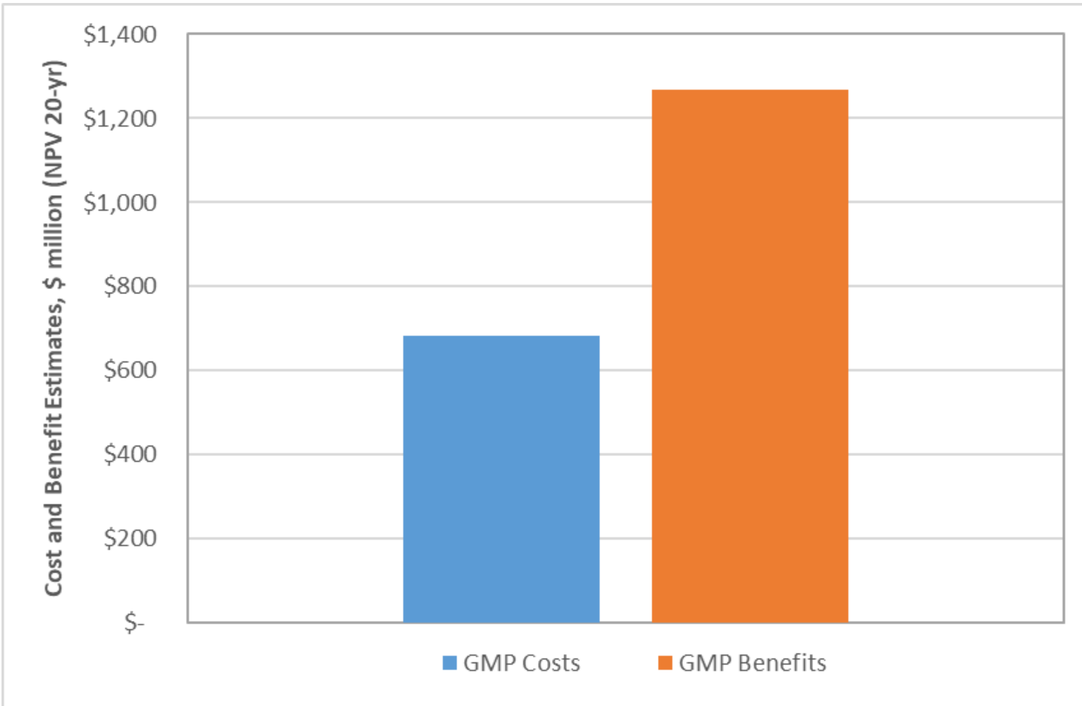

Figure 26 Summary of Estimates for Cost and Benefits of GMP[45]

The resulting BCR estimate is 1.86 for the full portfolio of the ten-year GMP investments on a 20-year NPV basis. Note that additional qualitative benefits described in *Section 4.3: Qualitative Discussion* are also significant.

Alternative BCA Formulations

The effect of alternative BCA formulations for a range of key input assumptions is shown in Table 26. These sensitivities all produce BCRs greater than 1 with some as high as 2.19 (i.e., "Societal Discount Rate").

Table 26: Summary of Benefit-Cost Ratios for Alternative BCA Formulations

MA GMP Alternative BCA Formulation	Benefit-Cost Ratio (20-yr NPV)
Base Case	1.86
Societal Discount Rate	2.19
ROP DRIPE Included	1.92
FLISR SAIFI Excluded	1.62
15-Yr Analysis Period	1.60

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

Annual Costs and Benefits

Estimated annual costs and benefits are shown in Figure 27 on a nominal basis. Most costs occur throughout the program based on deployment schedules developed by the Company for each grid modernization solution through 2031. Note that these costs include the revenue requirement for capital investments in Advanced Field Devices. The revenue requirement cost contribution continues through 2041, even though Advanced Field Device deployment ends in 2031. Most benefits occur in the later years due to steady deployment of grid modernization and its associated benefits compared to the Reference Case. Simple payback, or the length of time an investment reaches a break-even point, is estimated to be achieved in less than nine years based on the quantified costs and benefits included in this GMP.

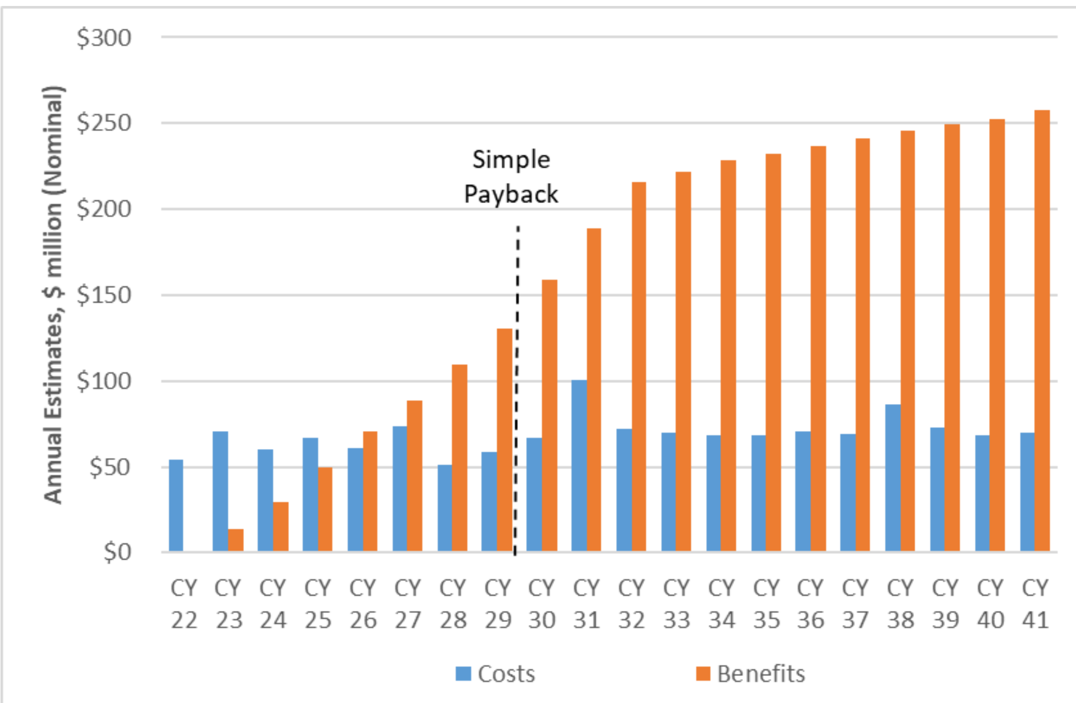

Figure 27: Annual BCA Results for GMP

All cost and benefit results are described in more detail in *Section 4.2.2: Cost Estimation* and *Section 4.2.3: Benefit Estimation.*

4.2.2 Cost Estimation

The cost estimates used in the BCA include all costs incurred to deploy and maintain 10 years of grid modernization investments through the end of the 20-year financial analysis period, including capital expenditures (CAPEX) and operating expenditures (OPEX). OPEX includes both run-the-business (RTB) OPEX and non-RTB OPEX for all solutions presented in the GMP roadmap. Each of these types of cost are described below.

- Capital Expenditures (CAPEX): Labor and non-labor costs related to system specification, design, testing, equipment and software purchase, installation, and cost of removal
- Run-the-Business Operating Expenditures (RTB): A category of OPEX that typically extends beyond the plant-in-service or go-live date for the investment, and includes on-going support (e.g., administrative, G&A overhead), software maintenance fees, monthly cellular service fees, and equipment maintenance
- Non-RTB Operating Expenditures (Non-RTB OPEX): Typically, labor costs related to strategic work (e.g., develop roadmaps, research alternative business systems), evaluation and selection of alternatives, vendor selection, and training

Table 27 summarizes the GMP cost categories and associated grid modernization solutions mapped to the MA GMP investment categories in Figure 2.

Table 27: Grid Modernization Cost Categories and Solutions

GMP Cost Category	GMP Solution (MA GMP Investment Category)
Advanced Field Devices	• Feeder Monitors (Monitoring & Control, VVO, ADA, MV&S) • Advanced Capacitors & Regulators (VVO/CVR, MV&S) • Advanced Reclosers & Breakers (ADA, MV&S)
Control Center and Back Office	• ADMS Core Functionality (ADMS) • Mobile Dispatch (ADMS) • RTU Separation (ADMS) • Distribution PI Historian (ADMS) • GIS Data Enhancements (ADMS) • Enterprise Integration Platform (IT) • Data Management (IT) • Cyber Services (IT) • FERC Order 2222 (FERC O2222)
Telecommunications	• Communications & Networking (Communications) • INOC (Communications)
Modular Optimizing Applications	• VVO/CVR Platform/Controller (VVO) • FLISR Platform/Controller (ADA) • DERMS (DERMS)

Cost estimates are summarized in Figure 28 and more detailed cost estimates for each GMP investment are presented in Table 28. Costs are presented on a 20-year NPV basis. The major investments for the GMP are due to the deployment of the Advanced Field Devices (i.e., Feeder Monitors, Advanced Capacitors and Regulators, Advanced Reclosers and Breakers), ADMS Core Functionality, and Communications & Networking.

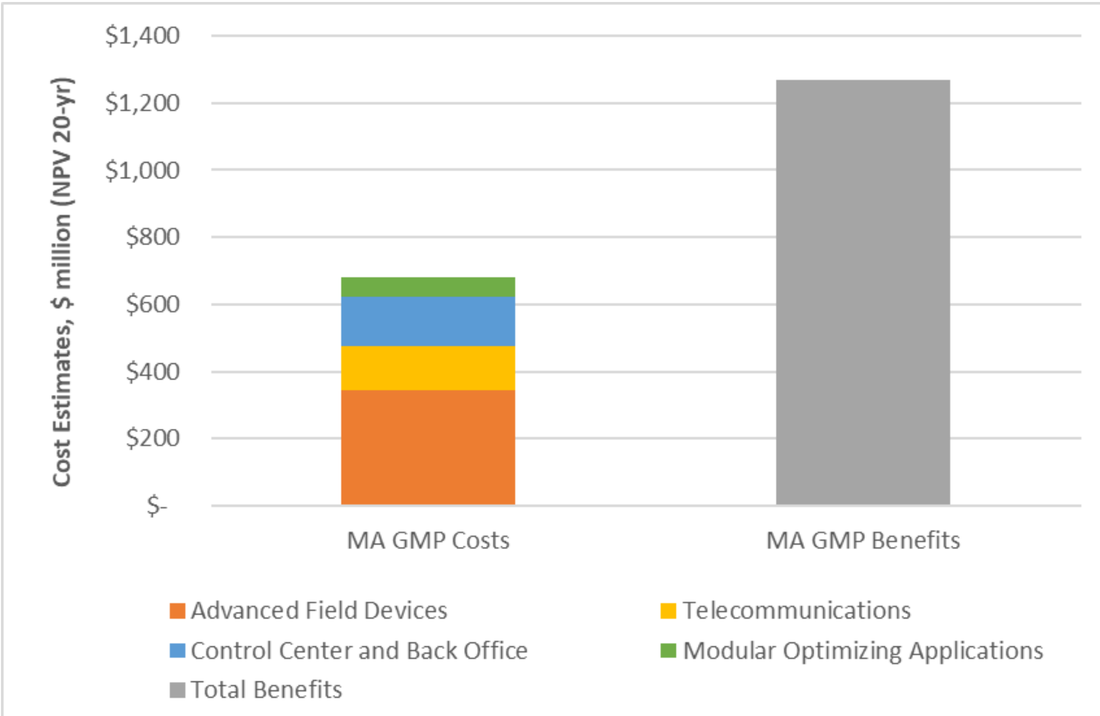

Figure 28: Cost Estimates for GMP

Table 28: Cost Estimates for All Cases and Scenarios

GMP Cost Estimates	20 Year NPV ($ million)
Feeder Monitors (Monitoring & Control, VVO, ADA, MV&S)	$80.47
Advanced Capacitors & Regulators (VVO, MV&S)	$152.36
Advanced Reclosers & Breakers (ADA, MV&S)	$111.65
ADMS Core Functionality (ADMS)	$62.26
Mobile Dispatch (ADMS)	$17.58
RTU Separation (ADMS)	$4.51
Distribution PI Historian (ADMS)	$2.24
GIS Data Enhancements (ADMS)	$16.78
Enterprise Integration Platform (IT)	$6.95
Data Management (IT)	$6.85
Cyber Services (IT)	$4.47
FERC Order 2222 (FERC Order 2222)	$37.89
Communications & Networking (Communications)	$109.73
INOC (Communications)	$22.18
VVO/CVR Platform/Controller (VVO)	$31.14
FLISR Platform/Controller (ADA)	$0.26
DERMS (DERMS)	$13.45
Total	**$681.06**

The horizon of the GMP BCA spans 10 years of investment and the maturity of the cost estimates presented and utilized in the BCA are of varying levels of refinement. Some of the projects in the GMP are still in the requirements definition phase of development at this time (e.g., DERMS Implementation), so these cost estimates are still in the initial stage of estimation. Cost estimates will be refined over time, and the closer an investment gets to implementation, the more detailed and precise the estimate will become. Also, note that while the cost estimates used in the BCA include all the costs necessary to deploy and maintain the grid modernization investments proposed in this GMP, costs associated with complementary and supporting elements outside of the GMP were excluded from this analysis.

4.2.3 Benefit Estimation

Many of the benefit impacts resulting from the proposed GMP portfolio of solutions have been quantified using the previously described BCA methodology and inputs based on detailed modeling. The Company used well-established BCA methodologies from other Company BCA efforts, including the Energy Efficiency and Demand Response (DR) Program's Total Resource Cost test. The source for many of the avoided cost value components is the "*Avoided Energy Supply Costs in New England: 2021 Report*" (AESC 2021 Study) prepared by Synapse Energy

Economics for the AESC 2021 Study Group, May 15, 2021. This report was sponsored by the electric and gas energy efficiency program administrators in New England and is designed to be used for cost-effectiveness screening in 2022 through 2024.

The quantified GMP benefit descriptions are presented in Table 29. In many cases, the quantified benefit is an avoided cost that is calculated based on the difference (or "delta") between the Reference Case and the Grid Modernization Case. Benefits that were qualitatively addressed are presented in *Section 4.3: Qualitative Assessment*.

Table 29: Quantified GMP Benefit Category Descriptions

GMP Benefit Category	Description of Quantified Benefit
Avoided O&M Costs	OPEX Labor Efficiency due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise; due to GIS automation decreasing time spent creating and maintaining the various network models used for distribution system planning and operational models; and due to ADMS-based mobile dispatch digitizing field information, improving customer outage notification and ETR communications, increasing crew visibility and automating dispatch
	Avoided Legacy OPEX Investments in RTB telecoms costs from future DERs, due to the proposed investments in Communications & Networking
Avoided Capital Costs	Avoided Legacy CAPEX Investments in recurring standalone OMS license, VVO/CVR license (for existing deployments), and telecommunication investments necessary to convert DS0 to T1 circuit technology due to the proposed investments in ADMS, ADMS-based VVO/CVR App, and Communications & Networking
Customer Benefits	Reduced Customer Energy Use and System Capacity Requirements as a result of operating distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand from customer appliances (i.e., VVO/CVR)
	Reduced Outage Restoration Time due to the ability of the system operator and control system to quickly generate switch orders (i.e., ADMS-based SOM) and locate and isolate a fault and restore power (i.e., ADA/FLISR) rather than waiting for field crews to locate, isolate, and restore power
Societal Benefits*	Benefits due to a reduction in non-embedded central power plant emissions of CO_2 resulting from Reduced Customer Energy Use

* Note that while most emissions reductions benefits are included in Societal Benefits, some are included as Customer Benefits due to "embedded" CO_2 costs associated with requirements of the Regional Greenhouse Gas Initiative (RGGI), 310 CMR 7.74, and 310 CMR 7.75.

Benefit estimates are summarized in Figure 29. Benefits are presented on a 20-year NPV basis. The largest single benefit category is Customer Benefits, which exceeds grid modernization costs even before Societal Benefits, Avoided O&M Costs, and Avoided Capital Costs are included.

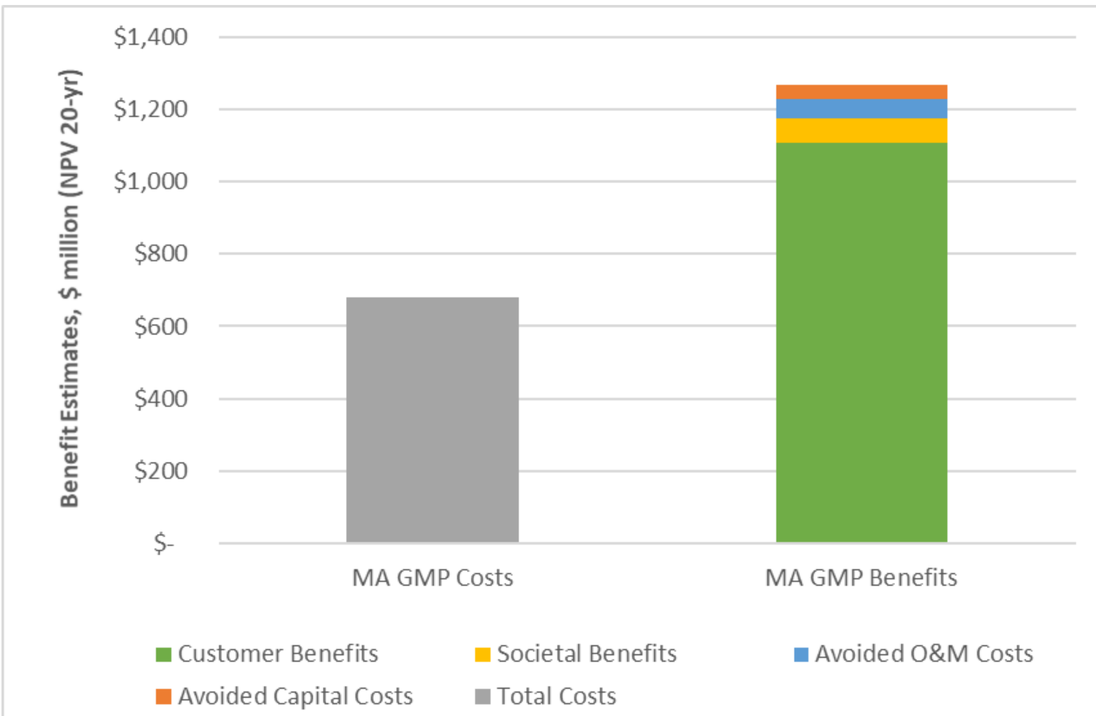

Figure 29: Benefit Estimates for GMP

Benefit estimates for each specific quantified benefit are presented in Table 30. Benefits are presented on a 20-year NPV basis. The top five benefits are summarized below.

- FLISR value of reliability improvement due to Reduced Outage Restoration Times
- Reclosers value of reliability improvement due to Reduced Outage Restoration Times
- Energy spot market price savings due to Reduced Customer Energy Use from VVO/CVR
- Non-embedded CO_2 benefit due to Reduced Customer Energy Use from VVO/CVR
- Transmission capacity savings due to Reduced System Capacity Requirements from VVO/CVR

Table 30: Detailed Benefit Estimates

Benefit Categories	Benefit Impact	Quantified Benefit	20 Year NPV ($ million)
Avoided O&M Costs	OPEX Labor Efficiency	DER RTB Telecoms Savings	$23.30
		Mobile Dispatch Savings	$22.92
		GIS Network Model Savings	$4.50
		Maintenance Response Savings (NRAs)	$2.43
Avoided Capital Costs	Avoided Legacy CAPEX Investments	DS0 to T1 Telecoms Savings	$32.49
		Stand-alone VVO/CVR License Savings (Existing)	$4.17
		Stand-alone OMS License Savings	$3.05
Customer Benefits	Reduced Customer Energy Use (VVO/CVR)	Energy Spot Market Price Savings (Excluding RGGI Cost)	$97.35
		DRIPE Energy Benefit	$17.75
		Embedded CO2 Benefit (RGGI Cost)	$8.21
		Cross-DRIPE Benefit	$5.74
	Reduced System Capacity Requirements (VVO/CVR)	Transmission Capacity Savings	$43.69
		Distribution Capacity Savings	$34.81
		Generation Capacity Savings	$25.48
		DRIPE Capacity Benefit	$13.64
	Reduced Outage Restoration Time	FLISR Value of Reliability Improvement	$615.14
		Reclosers Value of Reliability Improvement	$227.20
		SOM Value of Reliability Improvement	$16.81
Societal Benefits	Reduced Customer Energy Use (VVO/CVR)	Non-Embedded CO2 Benefit	$69.90
Total			**$1,268.59**

4.2.4 Alignment with D.P.U. 12-76

The GMP benefit category alignment with the D.P.U. 12-76-C benefit categories is presented in Table 31. Twelve D.P.U. 12-76-C benefits were quantified in the Company's GMP BCA. Other benefits are qualitatively addressed in *Section 4.3: Qualitative Assessment*.

Table 31: Quantifiable Benefit Category Mapping to DPU Order 12-76 Benefits

GMP Benefit Category	DPU Order 12-76 Benefit Category	DPU Order 12-76 Benefit Name	GMP Quantified Benefit	20-Year NPV ($ million)
Avoided Capital Costs	Distribution Capital Savings	Deferred Capital Replacement	DS0 to T1 Telecoms Savings	$32.49
			Stand-alone VVO/CVR License Savings (Existing)	$4.17
			Stand-alone OMS License Savings	$3.05
Avoided O&M Costs	Distribution O&M Savings	Reduced Distribution Equipment Maintenance Cost	Maintenance Response Savings (NRAs)	$2.43
		Reduced Distribution Operations Cost	DER RTB Telecoms Savings	$23.30
			Mobile Dispatch Savings	$22.92
			GIS Network Model Savings	$4.50
Customer Benefits	System Optimization	Reduced Energy Use Due to Optimized System Voltages	Energy Spot Market Price Savings (Excluding RGGI Cost)	$97.35
			Cross-DRIPE Benefit	$5.74
	Electricity Cost Savings	Reduced Electricity Cost	DRIPE Energy Benefit	$17.75
			DRIPE Capacity Benefit	$13.64
		Capacity Savings	Capacity Savings (Transmission, Generation, and Distribution)	$103.98
	Power Interruptions	Reduced Sustained Outages	Value of Reliability Improvement (FLISR, Advanced Reclosers, and SOM)	$859.15
		Reduced Outage Frequency		
		Avoided Cost to Restart C&I Business Operations		
		Avoided Cost of Spoiled Inventory		
Societal Benefits	Air Emissions	Avoided GHG Emissions Compliance Cost	Embedded CO_2 Benefit (RGGI Cost)	$8.21
		Avoided SO_2, NO_x, and PM-10 Emissions Compliance Cost	Included in "Energy Spot Market Price Savings (Excluding RGGI)"	$-
		N/A	Non-embedded CO_2 Benefit	$69.90
Total				**$1,268.59**

4.2.5 Sensitivity Analysis

Developing a 10-year plan in a fast-changing environment requires acknowledgement that there are a number of uncertainties. These uncertainties create risks with respect to the scope and timing of investments within the GMP and the benefits to be achieved. The Company has taken several steps to better understand uncertainties and manage the associated risks, most notably creating this 10-year GMP roadmap to guide the development of projects and programs.

The GMP BCA provides the Company and external stakeholders with a better understanding of the key factors that impact the quantified benefits and costs and allows all parties to focus future efforts on better understanding and influencing those factors in a positive way. The following sensitivity analysis quantitatively evaluates the BCA impact of some of the key factors.

4.2.5.1 Alternative BCA Formulations

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

1. Use lower societal discount rate (i.e., Inflation = 2.33%) instead of the Company's after-tax weighted average cost of capital (WACC = 7.56%)
2. Include Rest of Pool (ROP) DRIPE effects
3. Exclude SAIFI value of reliability improvement benefit due to FLISR
4. Use 15-year financial analysis period for the NPV calculation instead of 20-years

Societal Discount Rate

The Company maintains that the most reasonable rate to discount future year costs and benefits for GMP investments is the Company's after-tax WACC (currently 7.56% nominal) due to the fact that the GMP investments are utility investments, and after-tax WACC is the Company's effective discount rate. However, some stakeholders requested to see results given a lower societal discount rate. Using a lower nominal discount rate of 2.33%, which is consistent with the Company's 2019-2021 Energy Efficiency Plan discount rate,[46] values cash flows in later years more than a higher discount rate. Since most costs occur in early years, but benefits occur in later years, the net effect is an increase in the benefit-cost ratio.

ROP DRIPE Included

Demand Reduction Induced Price Effect (DRIPE) is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to reduced demand from electric system investments. AESC provides values for two types of DRIPE benefits: "Intrastate" and "Rest of Pool" (ROP). Intrastate DRIPE benefit takes credit for the reduced clearing price for Massachusetts customers, while ROP DRIPE benefit takes credit for the reduced clearing price for customers across New England. The base case BCA results exclude ROP DRIPE based on the Company's interpretation of the Societal Cost Test used for this filing, which focuses on benefits accrued to Massachusetts customers. While the base case BCA includes only Intrastate DRIPE,

[46] The Company's 2019-2021 Energy Efficiency Plan uses a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a discount rate that indicates that energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk. The 2019-2021 Energy Efficiency Plan uses a nominal discount rate of 2.33% (real discount rate of 0.46%).

stakeholders expressed an interest in seeing results that include the ROP portion of DRIPE as well. Including ROP DRIPE will increase the GMP benefits, which will increase the benefit-cost ratio.

FLISR SAIFI Benefit Excluded

The targeted deployment of Advanced Reclosers and Breakers, which is part of the Company's GMP, can reduce both the duration and frequency of all outages including momentary outages (i.e., outages lasting less than 1 minute). The addition of FLISR to the deployment of Advanced Reclosers and Breakers will reduce outage duration and frequency, but only the frequency of sustained outages (i.e., outages greater than 1 minute). Without FLISR, outage durations might be an hour or more for some customers while crews are dispatched to locate and isolate the fault and restore power to customers downstream of the fault. With FLISR, these steps can be performed in a matter of seconds, so outages can be converted from sustained to momentary outages. Typical reliability metrics include outage duration, which is reported based on the System Average Interruption Duration Index (SAIDI) and outage frequency, which is reported based on the System Average Interruption Frequency Index (SAIFI). In Massachusetts, SAIFI is reported based on the frequency of sustained outages lasting greater than 1 minute. So, reducing customer outages to less than 1 minute will reduce the reported SAIFI.

The GMP's "FLISR value of reliability improvement" benefit is estimated based on the monetization of customer impacts as presented in the US Department of Energy's (DOE's) Interruption Cost Estimate (ICE) Calculator, which uses SAIDI and SAIFI improvements as inputs to the Calculator.[47] The Company believes it is appropriate to quantify the FLISR benefit using both the estimated SAIDI and SAIFI improvements as inputs to the DOE ICE Calculator. However, some internal stakeholders expressed concern over the uncertainty of the actual customer value of converting a sustained outage to a momentary outage. Therefore, this sensitivity case was developed to show the impact to the BCA if SAIFI reductions were excluded for the FLISR benefit. Excluding the FLISR SAIFI benefit will decrease the GMP benefits, which will reduce the benefit-cost ratio.

15-Year Analysis Period

The base case GMP and AMI BCAs use a financial analysis (i.e., NPV) period of twenty-years (i.e., CY22-41). Twenty years was selected for the base case because it is close to the expected life of many of the GMP and AMI investments, and it also provides a reasonable amount of time for benefits to be realized, particularly for investments made towards the end of the Plan period, which spans from CY22-31. However, D.P.U. 12-76-C requested a "BCA time horizon" of 15 years, which the Company interprets to mean a financial analysis period of 15 years. Therefore, this sensitivity case was developed to show the impact of a shorter 15-year NPV. Reducing the NPV to 15 years results in higher GMP costs relative to benefits, because most costs occur in early years, but benefits occur in later years. The net effect is a decrease in the benefit-cost ratio.

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

Results

A summary of BCR results for the alternative BCA formulations is shown in Figure 30. Table 32 provides the specific cost and benefit increases and decreases estimated. The Company notes that, while some of the alternative formulations could be combined in an “a la carte” manner to surmise combined effects (e.g., ROP DRIPE, FLISR SAIFI Excluded), the effect of the Societal Discount Rate and 15-Year Analysis Period formulations are more complex and cannot be combined with other alternative formulations without additional analysis.

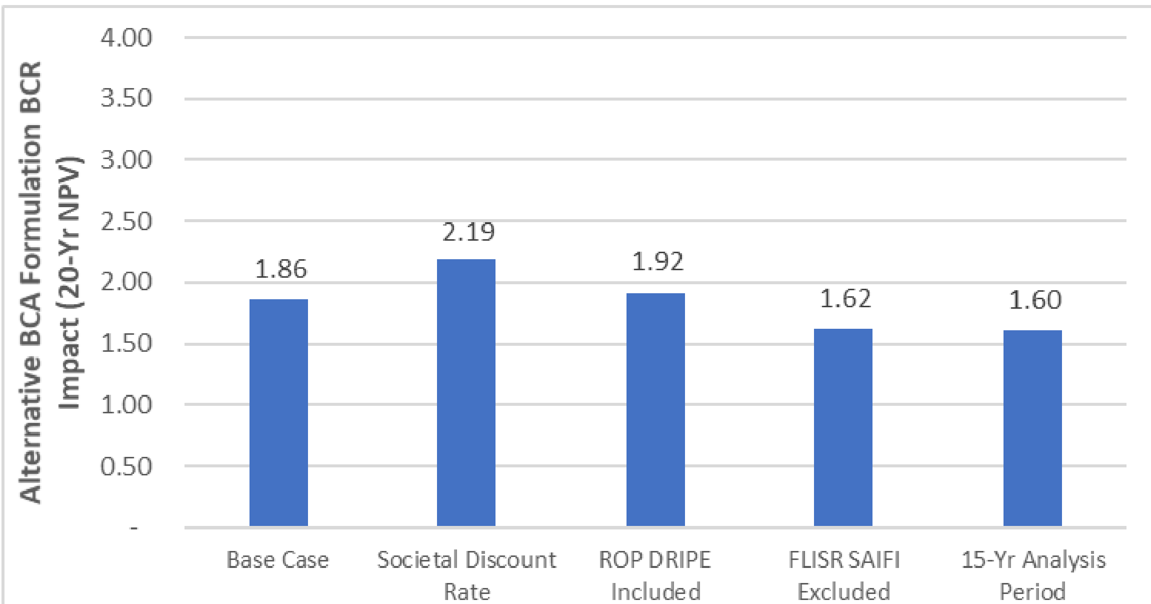

Figure 30: Impact of Alternative BCA Formulations on BCRs

Table 32: Impact of Alternative BCA Formulations on BCA Results

GMP Alternative BCA Formulations, 20-Yr NPV	Effect on Costs ($M)	Effect on Benefits ($M)	BCR
Base Case	$ 681.06	$ 1,268.59	1.86
Societal Discount Rate	$ 401.64	$ 1,102.29	2.19
ROP DRIPE Included	$ -	$ 36.11	1.92
FLISR SAIFI Excluded	$ -	$ (167.22)	1.62
15-Yr Analysis Period	$ (99.58)	$ (336.76)	1.60

The quantified benefits attributed to the GMP outweigh the costs in all alternative scenarios. ROP DRIPE effects, and a lower societal discount rate resulted in additional quantified benefits, which increased the BCR results by between about 3-17% compared to the base case. While excluding the FLISR SAIFI benefits and using a 15-year financial analysis period had negative impacts on the quantified benefits, the BCR was still greater than one.

4.2.5.2 Key Input Assumptions Sensitivity

In order to assess the impact of important variables on the BCA results, a range of values was developed for a set of key input assumptions for the GMP investments. This sensitivity analysis uses a range of more conservative and less conservative assumptions than the base case, as summarized below.

- Avoided Cost of Carbon benefit assumption range from 75% to 125% of the base case input assumption. Note that this sensitivity also addresses the added uncertainty of future electric sector emissions rates.
  - Base case = \$125/short ton CO_2 equivalent based on New England marginal abatement cost estimates assuming a cost derived from electric sector technologies. This cost is based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard.[48]
  - Low end of the range was selected to capture future "global" marginal abatement cost based on the cost of large-scale carbon capture and sequestration (e.g., \$92/short ton CO_2 equivalent).[49]
  - High end of the range was selected to capture damage cost estimates, which can be much higher than abatement cost estimates.
- VVO/CVR-based customer energy use and system capacity requirement reduction range from 2% to 4%
  - Base case = 2.72% based on early results from the National Grid's VVO/CVR Projects.
  - Range was selected to capture the variability of early measurement and verification (M&V) results from National Grid's VVO/CVR Pilot in Rhode Island. The high end of the range also captures the 4% energy savings the Company's VVO/CVR industry partner has demonstrated with other utilities.
- GMP portfolio investment cost assumptions range from 70% to 130% of the base case input assumption
  - Base case = \$681 million (20-year NPV) based on CAPEX, OPEX, and RTB cost estimates for each GMP solution
  - Range of +30% and -30% was selected for consistency with other National Grid BCA sensitivity analyses

Results

Figure 31 shows the range of benefit-cost ratios achieved by each key input assumption sensitivity.

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[48] Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2021 Report*, 16 (Orig. released March 15, 2021, amended May 14, 2021).

[49] *Id.*

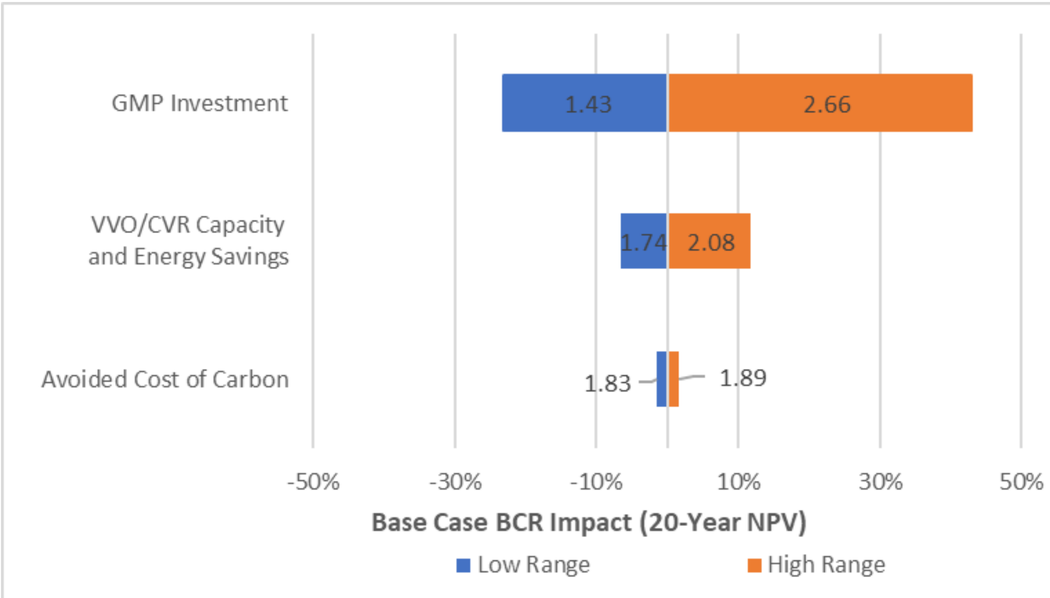

Figure 31: Impact of Key Input Assumption Sensitivity on the Base Case Benefit-Cost Ratio

As can be seen, uncertainty in the GMP investment cost estimates creates the widest range of potential BCR results. Fortunately, a large fraction of the GMP investment cost estimate is based on the deployment of solutions that the Company has significant experience with, including Advanced Reclosers and Breakers, Advanced Capacitors and Regulators, and Feeder Monitors. However, an exact cost estimation for all solutions in the GMP can be challenging given the long timeframe of the GMP analysis.

Another key uncertainty is the VVO/CVR energy savings. Uncertainty in VVO/CVR energy savings is expected to be reduced over time as the Company continues VVO/CVR pilot projects and M&V in all of its jurisdictions. The avoided cost of carbon uncertainty has relatively smaller impacts.

4.3 Qualitative Benefits Assessment

In addition to the quantified benefits presented in this BCA, the Company is providing additional non-quantified benefits that should be recognized qualitatively. These benefits are not quantified at this time due to lack of data or lack of an accepted method. However, these benefits represent important additional grid modernization value, as is explained in this section. If considered as part of the BCA, these benefits can be thought of as directionally increasing the BCR and potentially making the grid modernization programs even more valuable and cost-effective. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

4.3.1 Avoided O&M Cost

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

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

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

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

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

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

Improved Operational Efficiency and DER Utilization due to Accurate Short Term Load Forecasts: Through advanced notification of granular forecasted system constraints from load forecasting and integration of load forecasts with ADMS applications (e.g., load flow simulation and contingency analysis), operational data used to inform distribution system operational planning, optimal system reconfiguration, what-if studies and scheduling of field workforce can lead to more efficient distribution system operations. In addition, greater certainty of near-term system needs informed by accurate short-term load forecasts can lead to more efficient activation of existing and new DER programs for DER grid services, and the opportunity to evolve the use of demand response, distributed generation, and storage resources to support grid needs and balance load and supply on the system.

4.3.2 Avoided Capital Costs

Avoided Distribution-System Infrastructure: VVO/CVR, ADA, ADMS, and other supporting solutions will enable load optimization (i.e., ability of the system operator to autonomously or remotely control power flows on the distribution system, by maintaining voltage compliance across all times of the year and across the distribution system with various levels of DER penetration), rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.

4.3.3 Customer Benefits

Improved DER Experience due to DER Integration: Grid Optimization and DER Operational Control through ADMS and DERMS will allow for a higher level of DER operational integration and could be used to reduce interconnection costs and enable larger DER interconnections making DERs more cost effective to deploy in the state. These investments enable improved customer DER experience, such as better informed DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third-party information sharing and services. By reducing costs and other barriers to interconnection, grid modernization will help more Massachusetts customers invest in their own DER technologies in areas where these technologies are most cost-effective. The grid modernization capabilities that provide this benefit include:

Improved DER Experience and Operation due to Accurate Short-Term Load Forecasts: More accurate short-term load forecasts as input into distribution system security analysis and feasibility assessment of DER schedules, especially for DERs participating in the ISO-NE wholesale market, can reduce the need to redispatch DER and provide advance notice of potential operational restrictions of DER due to distribution system constraints.

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

Reduced DG Curtailment: ADA/FLISR, ADMS, DERMS, and other supporting solutions enable the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance.

Reduced Customer Energy Use due to Network Model Integration: Beyond FY26, when VVO/CVR is centralized and controlled by ADMS rather than the existing standalone VVO/CVR platform, the Company anticipates additional energy saving benefits beyond what has been assumed in the quantitative BCA, because the ADMS-based VVO/CVR platform will operate on the "as-switched" network model informed by underlying real time load flow. This also allows VVO/CVR to operate when the grid is in an abnormal configuration due to emergency or planned circuit reconfigurations resulting in additional incremental benefits in addition to the baseline VVO/CVR energy savings.[50] Additional analysis and experience with the ADMS-based VVO/CVR controller is necessary to accurately quantify this benefit.

Reduced Customer Energy Costs due to Enhanced Load Shift: Grid modernization investments, especially when coupled with AMI and TVR, can facilitate load shifting from high demand periods to lower or even negative load (i.e., excessive renewable DG generation) periods by enabling flexible demand. Examples of flexible demand include customer demand response, EV charging, stationary energy storage, smart appliances including thermostats, and perhaps in the future, electric vehicle-to-grid discharging. This shifting of energy consumption between time periods can reduce customer energy costs, avoid distribution system costs, and maximize renewable generation utilization. Impacts of this large a load shift on customer energy prices were not quantified due to a number of uncertainties at this time.

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

Improved Short-Term Forecasting for Operations due to Granular Data: Better forecasting and monitoring of load, generation, and grid performance enabled by AMI, ADMS (i.e., ADMS-based load forecasting application), Advanced Field Devices, and DERMS can enable grid operators to further optimize system configuration and actively manage grid demand and grid supply to maximize asset utilization and allow dispatch of a more efficient mix of generation and ancillary services (e.g., spinning reserve, frequency regulation)[51]. Improved forecasting and monitoring of load and generation may also allow for less restricted DER operation in areas susceptible to system voltage or thermal constraints and allow NWA assets to be utilized for other beneficial uses if the grid operator can forecast that it does not need the NWA for reliability needs during a certain time period.

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

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

In addition, the current method to addressing voltage issues due to DERs is setting a fixed absorbing power factor. This functionality can be extremely helpful but is limited by the fact that it is always absorbing reactive power at a fixed rate even at times when the system does not need it. Today, the reactive power absorbed often comes from a transmission source, which results in losses in the system. With investments in DERMS and the ability to adjust power factor settings dynamically using customer owned smart inverters,[52] reactive power absorption would only occur when needed, which can decrease losses in both the DG inverter output power and generating transmission-sourced VARs.[53] EPRI has done some work to quantify this value, but the value is highly dependent on the location of the DER on the feeder and the penetration of DER on that feeder. Given the complexity of these calculation and the early stage of its development, the Company has not quantified this benefit in the GMP.

Reduced Customer Outages due to Granular Data: The granular and more frequent operational and performance data collected from AMI, Advanced Field Devices and ADMS, will help the Company determine the asset health of equipment and identify where maintenance should be performed and may help detect asset failures earlier, which would support condition-based maintenance and mitigate possible equipment failure related outages. AMI meters will be capable of providing granular data that can be used to analyze equipment performance such as transformer health analysis. This will be achieved through ongoing investment and future expansion of the Data Management investments which includes data capture and storage, data backhauling requirements, analytics

[51] Ancillary services are necessary to ensure the reliable and efficient operation of the grid.
[52] Smart inverter power factor adjustments can be made seasonally or based on a Volt/Volt-Ampere Reactive (VAR) function where reactive power is injected based on voltage.
[53] Electric Power Research Institute, *Tailoring IEEE 1547 Recommended Smart Inverter Settings Based on Modeled Grid Performance* (December 2020). https://www.epri.com/research/products/000000003002020102

tools, and system integration. In addition, AMI provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of ADMS, which can improve the isolation and restoration capabilities of FLISR.

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

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

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

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

Improved Customer Satisfaction due to Better Access to Markets: In line with the discussion above regarding FERC O2222, the flexibility to eventually tie into competitive distributed grid energy markets and products will provide customers with options for less costly, and more readily available, electric services. The ADMS advanced applications platform and DERMS solution will be foundational enablers of this benefit, in conjunction with a yet to be standardized industry exchange platform. The ability to procure grid support for customers from the market on a transactive energy basis is envisioned. As detailed in the FERC O2222 section, the creation of this market and its products are still nascent, thereby the full impact of this benefit, and how these products would be used, can only be qualitatively noted at this time.

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

4.3.3 Societal Benefits

Economic Development Benefits due to GMP Investments: The proposed GMP investments will result in positive economic impacts due to increased economic activity, which can manifest itself in the form of increased gross domestic product (GDP) for the Commonwealth. Positive economic impacts can encompass increased job years, incomes, state tax revenues and the increased competitiveness of Massachusetts business firms. While economic development benefits are important, quantifying these benefits and including them in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits related to GMP investments, which can discredit other components of the BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the Company did not include a quantification of the economic development benefits due to the GMP investments.

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

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

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

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

5. Conclusion

By 2030, the Company envisions that households and businesses will be connected to millions of DERs, smart devices, and other innovative technologies that have yet to be invented. At the same time, customers and communities will also likely experience more extreme weather conditions and outages due to climate change. The Company's second GMP will continue to implement critical, foundational investments across the distribution system and unlock the advanced capabilities that will enable the Company to interact with these devices in real-time in order to optimize generation and demand, while at the same time maintaining reliability of the distribution system under the increasing challenges of unpredictable and dynamic conditions.

As described previously, the Company's second GMP contains a comprehensive suite of investments and initiatives that will modernize the Company's distribution system and deliver significant customer benefits, including energy supply savings, reduced outage duration, reduced numbers of customers impacted by outages, and improved system operations and system planning. With this plan, the Company will be well-prepared to play a transformative role in achieving the Commonwealth's and the Department's goals for a clean and affordable energy future.

Exhibit NG-GMP-3 CONFIDENTIAL

Grid Facing Investments Benefit-Cost Analysis Model

(See Excel file)

Exhibit NG-GMP-4

Proposed Changes to Existing Performance Metrics

Grid Modernization Plan
Performance Metrics
Revised July 11, 2019

Massachusetts Department of Public Utilities
D.P.U. 15-120, 15-121, 15-122

1 INTRODUCTION

In D.P.U. 12-76-B, the Department of Public Utilities (the "Department") directed NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid") and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (individually, the "Company" and collectively, the "Companies") to include in their Grid Modernization Plans ("GMPs") two types of company-specific metrics: (1) infrastructure metrics that track the implementation of grid modernization technologies and systems; and (2) performance metrics that measure progress towards the objectives of grid modernization. D.P.U. 12-76-B, at 30. In addition to the company-specific metrics, the Department directed the Companies to jointly propose a common list of statewide metrics to be included in each GMP. Id., at 31. Furthermore, the Department directed the Companies to solicit stakeholder input in developing both statewide and company-specific metrics. Id., at 33.

Pursuant to the directives from the Department, each Company filed a GMP that included a list of proposed statewide and company-specific metrics for both infrastructure and performance. On May 10, 2018, the Department issued its Order regarding the individual GMPs filed by Eversource, National Grid and Unitil, respectively. In the Order, the Department preauthorized grid-facing investments over three-years (2018-2020) for the Companies and adopted a three-year (2018-2020) regulatory review construct for preauthorization of Grid Modernization investments. D.P.U. 15-120/15-121/15-122, at 137-173. The Department recognized that achievement of its Grid Modernization objectives[1] is a complex, long-term, and evolving endeavor and that, in the early stages of Grid Modernization, it is reasonable to expect that significant changes will take place associated with the introduction of new technologies and the costs associated with existing and new technologies. Id., at 107-108. Furthermore, the Department found that it is reasonable to expect that the Companies' understanding of how best to deploy Grid Modernization technologies to optimize their performance will evolve over time. Id.

As part of its decision regarding the Companies' GMPs, the Department approved the Companies' proposed statewide and company-specific infrastructure metrics. Id., at 198-201. In approving the infrastructure metrics, the Department found that the purpose of the metrics will be to record and report information: the metrics will not, at present, be tied to incentives or penalties. Id., at 197.

[1] The Department approved a modified set of Grid Modernization objectives, specifically: (1) optimizing system performance; (2) optimizing system demand; and (3) facilitating the interconnection of distributed energy resources. Id., at 95-106.

The Department ordered the Companies to establish baselines by which the grid-facing performance metrics will be measured against and to file them within 90 days of the Order. Id., at 203. To assist in the development of these baselines, the Department directed each of the Companies to develop and maintain information on its system design, operational characteristics (e.g., voltage, loading, line losses), and ratings prior to any deployment of preauthorized grid-facing technologies. Id. Additionally, the Department directed the Companies, when developing the proposed baselines to use, to the extent possible, information reported in the annual service quality filings, as well as other publicly available information. Id.[2]

Regarding the performance metrics proposed by the Companies in the GMPs, the Department determined that additional work was needed to develop metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the Grid Modernization objectives. Id., at 95-106. The Department ordered the Companies to file revised proposed performance metrics designed to address the preauthorized grid-facing investments and noted that it would convene a stakeholder process to facilitate review of the revised performance metrics. Id., at 202.

Consistent with the Department's directives, the Companies worked closely and collaboratively to develop a set of proposed performance metrics. This document describes the statewide, as well as company-specific, performance metrics that the Companies propose to use for evaluating their progress towards the Grid Modernization objectives. This document will also identify how the baseline for each metric is calculated and reported. Due to the complexity and data intensive nature of these metrics, the Company has not yet had the opportunity to calculate a baseline for all metrics. Additionally, the Company is undertaking the detailed design and planning analysis necessary to implement its GMP, which will necessarily inform several of the infrastructure metric baselines. Prior to undertaking the detailed data analysis necessary to develop the baselines, the Companies wanted to engage with the Department and stakeholders in the stakeholder process to determine if refinements to the proposed metrics were necessary, as well as receive final approval for the metrics. Following the Department's approval of a final set of performance metrics, the Companies will undertake the data analysis and report on the baselines in their respective initial annual GMP filings.

The chart below provides the complete set of metrics, both approved infrastructure metrics and proposed performance metrics, that the Companies will be utilizing to track and report on their progress under their individual GMPs, as well as their progress in achieving the Department's Grid

[2] The infrastructure metrics baselines are being filed separately by each Company.

Modernization goals.

Metric Type	Metric	Investment Category					
		Monitoring and Control	Distribution Automation	VVO	ADMS	Communications	Advanced Load Flow*
Performance	Volt Var Optimization (VVO) Baseline			X			
Performance	VVO Energy Savings			X			
Performance	VVO Peak Load Impact			X			
Performance	VVO Distribution Losses w/o AMF (Baseline)			X			
Performance	VVO Power Factor			X			
Performance	VVO – GHG Emissions			X			
Performance	Increase in Substations with DMS Power Flow and Control Capabilities				X		
Performance	Control Functions Implemented by Circuit				X		
Performance	Numbers of Customers that benefit from GMP funded Distribution Automation Devices		X				
Performance	Grid Modernization investments' effect on outage durations	X	X				
Performance	Grid Modernization investments' effect on outage frequency	X	X				
Performance	Advanced Load Flow - Percent Milestone Completion						X
Infrastructure	Grid Connected Distribution Generation Facilities						X
Infrastructure	System Automation Saturation	X	X				
Infrastructure	Number/ Percentage of Circuits with Installed Sensors	X					
Company Infrastructure	Number of devices or other technologies deployed	X	X	X		X	
Company Infrastructure	Cost for deployment	X	X	X		X	
Company Infrastructure	Deviation between actual and planned deployment for the plan year	X	X	X	X	X	X
Company Infrastructure	Projected deployment for the remainder of the three year term	X	X	X	X	X	X

On August 15, 2018, the Companies filed the proposed performance metrics as required by the Department following its approval of the Companies' modified GMPs. Each Company also filed baseline and target information for the statewide and Company-specific infrastructure metrics approved by the Department. D.P.U. 15-120/15-121/15-122 at 198-201. Following this submission, the Companies responded to information requests issued by the Department, the Department of Energy Resources ("DOER") and the Cape Light Compact ("CLC") consistent with the procedural schedule included in the September 28, 2018 Procedural Memorandum ("Memorandum") issued by the Department.

Additionally, the Department's Memorandum scheduled a technical session on the Companies' August 15, 2018 performance metrics filing. The Companies participated in the technical session, including presenting on the proposed performance metrics.[3] Following the technical session, the Department issued a Memorandum that set out required revisions to the August 15, 2018 performance metrics, as well as directed the Companies to develop additional performance metrics ("Metrics Revision Memorandum"). The Metrics Revision Memorandum set April 2, 2019 as the deadline for the Companies to file the revised and new performance metrics, with initial comments on the Companies' filing due on April 16, 2019 and reply comments due on April 23, 2019. Consistent with the directives contained in the Metrics Revision Memorandum, the Companies provided on April 9, 2019the required revisions to the initial set of performance metrics, as well as the new metrics required by the Department. Following further directives from the Department, the Companies filed additional revisions on June 6, 2019. National Grid made further revisions to its company-specific reliability performance metric located in Appendix C, pursuant to a Department directive, on July 11, 2019.

3 The Companies' February 13, 2019 technical session presentation can be found at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10379369

2 STATEWIDE PERFORMANCE METRICS

The Companies worked collaboratively to develop a list of statewide performance metrics for each Company to use to measure progress towards grid modernization. These statewide performance metrics were developed using many different resources. The Companies started by reviewing the metrics filed in each of their respective GMPs. In addition, Eversource had developed a comprehensive listing of potential metrics in its recent base rate case, D.P.U. 17-05, which included input from a large and varied group of stakeholders. Lastly, the Companies also reviewed performance metrics that other utilities throughout the country have used to measure their progress towards grid modernization.

Under their individual service quality plans, most recently revised in D.P.U. 12-120, the Companies are currently required to report on their performance in relation to numerous service quality metrics. The statewide performance metrics developed by the Companies in relation to their GMPs, as detailed below, are designed to be in addition to and not duplicate or modify the service quality metrics.

2.1 VOLT VAR OPTIMIZATION AND CONSERVATION VOLTAGE REDUCTION BASELINE

Volt VAR Optimization and Conservation Voltage Reduction ("VVO/CVR") is a solution that reduces energy consumption and demand without the need for customer interaction or participation. The core principle behind VVO/CVR is that load is more optimally utilized at lower voltages. The primary focus of VVO/CVR is to reduce circuit demand and energy consumption by flattening and lowering voltage profile on the circuit while maintaining customer service voltage standards. In addition, VVO/CVR systems allow for more gradual and responsive control of reactive power devices, such as capacitors, which will help improve the overall system power factor and reduce system losses. VVO/CVR allows customers to realize lower consumption without experiencing a reduction on the level of comfort and service.

Quantifying the exact impact of VVO/CVR is difficult to achieve given the Companies' current level of visibility into their systems. In a VVO/CVR system, the Companies will not have visibility into exactly what customer loads are being impacted, nor will they be able to identify the impact of the VVO/CVR system at any specific point in time. In order to have this level of visibility, the Companies would need to have interval metering at each residential customer's premises. At this time, none of the Companies have this level of residential metering. The metrics discussed below are all based on a measurement and verification ("M&V") process, which uses a statistical process to quantify the impact the VVO/CVR system has on the customers it serves.

2.1.1 Type of Metric

Statewide Performance Metric

2.1.2 Objective

Establish an impact factor for each VVO enabled circuit which will be used to quantify the peak load, energy savings, and greenhouse gas ("GHG") impact measures.

2.1.3 Assumptions

VVO dynamically controls and coordinates multiple devices to manage both voltage and reactive power. System-wide efficiency is achieved by simultaneously coordinating operations using continuous measurements from multiple sensors distributed across the circuit.

Once a circuit has VVO enabled, a M&V process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level VVO impact and baseline will be created.

2.1.4 Calculation Approach

The following data will be tracked and reported on a system and circuit basis:

a. Determine circuit loads through measurements during VVO on/off periods
b. Apply temperature corrections.
c. Develop load profiles.

As part of the baseline data capture, each VVO circuit will, at a minimum, capture hourly circuit data for real and reactive power.

2.1.5 Organization of Results

This information will be provided for each VVO enabled circuit and serve as the variable for calculating demand reductions or serve as variables for other calculations, such as reductions in GHG emissions. This calculation will be performed once and will support both circuit and system level impacts.

2.1.6 Baseline

The baseline will be calculated through M&V after each circuit and/or substation is placed into service. The baseline will be constructed using data collected when VVO is off during the VVO M&V period. The Company recommends that each VVO/CVR circuit undergo a nine- to twelve-month M&V period to capture one winter, one summer, and either the fall or spring shoulder seasons. The results from this M&V process will be used to estimate the impact the system has on system load for the next five-years. At the end of five years, the VVO M&V would be repeated to ensure that each Company is using recent and relevant results for metric reporting. Baselines will be reported during the first annual report following the field verification.

2.2 VOLT VAR OPTIMIZATION (VVO) ENERGY SAVINGS

2.2.1 Type of Metric

Statewide Performance Metric

2.2.2 Objective

This metric is designed to quantify the energy impact VVO/CVR has on the system with the intent of optimizing system performance.

2.2.3 Assumptions

Once a circuit has VVO enabled, a M&V process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level energy baseline and energy savings will be created.

2.2.4 Calculation Approach

The following data will be tracked and reported upon on a system and circuit basis after the VVO M&V process is complete:

a. VVO Energy Savings: Net energy savings (kWh), calculated by estimating the observed difference in load profiles for each circuit between the VVO enabled and VVO disabled states during the M&V period. This difference in load profiles is estimated via statistical analysis.
b. VVO Energy Baseline: Counterfactual energy usage (kWh), derived using statistical models constructed to estimate VVO energy savings and data collected when VVO is disabled during the M&V period. The VVO energy baseline assumes that VVO is disabled for the entirety of the M&V period.

2.2.5 Organization of Results

This information will be provided for each VVO enabled circuit at the end of the VVO M&V period and will support both circuit and system level impacts.

2.2.6 Baseline

VVO-related pre-investment baseline of energy delivered in kilowatt hours ("kWh") will be provided for each feeder and substation within the service territory for the years 2015, 2016, and 2017 to the extent that historical metering data are available. The pre-investment baseline of energy delivered will not be used to calculate VVO energy savings. Baseline for VVO energy savings is kWh observed during VVO disabled state during the M&V period and will be reported in the first annual report after the VVO M&V process is complete.

2.3 VVO PEAK LOAD IMPACT

2.3.1 Type of Metric

Statewide Performance Metric

2.3.2 Objective

This metric is designed to quantify the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand.

2.3.3 Assumptions

For this metric, the Companies will utilize active circuit M&V peak demand reduction results from individual circuits. No M&V results older than 5 years will be used.
Calculation Approach
The following data will be tracked and reported upon on a system and circuit basis:

a. VVO Peak Load Reduction: Net peak load reduction (kW), calculated by estimating the observed difference in load profiles for each circuit between the VVO enabled and VVO disabled states during peak hours during the VVO M&V period. This difference in load profiles is estimated via statistical analysis.

Each Company's individual peak load reduction attributed to VVO/CVR will be aggregated, resulting in the statewide estimated peak load reduction.

2.3.4 Organization of Results

Each Company will provide individual circuit VVO/CVR performance, GWs estimated demand reduction, as well as the summation of total system impact.

2.3.5 Baseline

VVO-related pre-investment baseline of annual peak load in million-volt ampere ("MVA") will be provided for each circuit and substation within the service territory for the years 2015, 2016, and 2017. The pre-investment baseline of annual peak load will not be used to calculate VVO peak load reductions. Baseline for VVO peak load reductions is kW observed during VVO disabled state during system peak hours during the VVO M&V period and will be reported in the first annual report after the VVO M&V process is completed.

2.4 VVO – DISTRIBUTION LOSSES WITHOUT AMF (BASELINE)

2.4.1 Type of Metric

Statewide Performance Metric

2.4.2 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. At the same time, VVO actively controls capacitor banks to maintain circuit power factors near unity. This distribution automation project will implement better voltage regulation to improve power quality and reduce losses. This includes the coordinated operation of a voltage regulator with a transformer load-tap changer at a substation.

Electrical loss in the circuit can be investigated using the difference between power provided by the circuit regulator and the total power delivered to the consumer loads. Electrical loss can also be investigated using amperage interval data and EDC-specific assumptions surrounding resistance.

2.4.3 Assumptions

There are many elements that contribute to distribution losses. These factors include:
• Unmetered load, such as street lights
• Electricity theft
• Circuit line losses

2.4.4 Calculation Approach

Using hourly data for real and reactive power, one can determine hourly line losses. This represents both technical and non-technical (e.g., theft) losses.

2.4.5 Organization of Results

This information will be provided on an annual basis for VVO enabled circuits. Results will be based upon the results at the end of each calendar year.

2.4.6 Baseline

The baseline for line losses will need to be developed once the circuit is enabled and the data is captured. The baseline for this metric will be reported in the first annual report after the M&V is completed.

2.5 VVO POWER FACTOR

2.5.1 Type of Metric

Statewide Performance Metric

2.5.2 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. Simultaneously, VVO actively controls capacitor banks to maintain circuit power factors near unity. Power factor is an indication of how efficiently the distribution system is delivering power. A distribution system operating at unity power factor delivers real power more efficiently than one operating at either a leading or lagging power factor. This performance metric seeks to quantify the improvement in power factor that VVO/CVR is providing. However, power factor alone is not sufficient to accurately describe the impact VVO/CVR has on the system. At low demand levels, a poor power factor is not as significant than at high demand levels. Therefore, some qualifications must be made to accurately track power factor.

2.5.3 Assumptions

Performance will be based on circuit level hourly power quality measurements at the substation.

2.5.4 Calculation Approach

This metric will use the following data:

- Circuit level hourly Power Factor
- Circuit level hourly on/off VVO/CVR Status

For this performance metric, only power factors corresponding to greater than 75 percent of a circuit's peak annual demand will be used to calculate power factor improvement.

The following data will be tracked and reported upon on a system and circuit basis:

a. VVO Power Factor: Power factor improvement, calculated by estimating the observed difference in power factor for each circuit between the VVO enabled and VVO disabled states during the VVO M&V period during hours corresponding to greater than 75 percent of a circuit's peak annual demand. This difference in power factor is estimated via statistical modeling for each circuit. A system power factor performance will be calculated by weighting circuit-level power factor estimates by the peak demand of each respective circuit.

2.5.5 Organization of Result

The results of this metric will be reported in a tabular format on a circuit-by-circuit basis and a total system tally. Power factor is a dimensionless metric.

2.5.6 Baseline

The baseline is power factor observed during VVO disabled state during the VVO M&V period during hours corresponding to greater than 75 percent of a circuit's peak annual load . The baseline for this metric will be reported in the first annual report after the VVO M&V process is completed.

2.6 VVO ESTIMATED VVO/CVR ENERGY AND GHG IMPACT

2.6.1 Type of Metric

Statewide Performance Metric

2.6.2 Objective

This metric is designed to quantify the overall GHG impact VVO/CVR has on the system. A GHG reduction estimate will be derived from the circuit level energy savings.

2.6.3 Assumptions

For this metric, each Company will utilize active circuit M&V energy reduction results from individual circuits. No M&V results older than five years will be used. To calculate GHG reductions, each Company will use GHG emissions factors consistent with those used in the 2019-2021 Three-Year Energy Efficiency Plans for displaced GHG.

2.6.4 Calculation Approach

This metric will use the following data:

- Circuit level M&V estimated VVO Energy Savings
- GHG emissions factors consistent with those used in the 2019-2021 Three-Year Energy Efficiency Plans

Each Company will use the energy reduction (MWh) attributed to VVO/CVR for each Company, and, when combined with other companies, statewide. CO2 avoided due to VVO/CVR will be calculated by multiplying the above energy reduction by a typical generation emissions factor based upon metric tons per MWh.

$$CO_2\ Emissions\ (tons) = Energy\ Savings\ (MWh) * CO_2\ Emissions\ Factor\ (tons/MWh)$$

The calculation will use the GHG emissions factors consistent with those used in the most recent version (currently 2019-2021) Three-Year Energy Efficiency Plans.

2.6.5 Organization of Results

Each Company will provide individual circuit VVO/CVR MWh estimated energy reduction and GHG impact, as well as the summation of total system impact.

2.6.6 Baseline

The baseline for this metric will be reported in the first annual report after the VVO M&V process is completed.

2.7 INCREASE IN SUBSTATIONS WITH DISTRIBUTION MANAGEMENT SYSTEM ("DMS") POWER FLOW AND CONTROL CAPABILITIES

2.7.1 Type

Statewide Performance Metric

2.7.2 Objective

This metric will demonstrate the progress in the Advanced Distribution Management System ("ADMS") investment by tracking the substations that have been equipped with power flow capabilities as well as the number of customers benefitting from the technology on each feeder. This metric will support the objective of optimizing system performance and more specifically improve asset utilization, improve reliability and integrate distributed energy resources. ADMS gives system operators increased visibility on the real time output of generating facilities. This metric is designed to demonstrate that the model is an accurate representation of field conditions.

2.7.3 Assumptions

A substation will be assumed to have DMS power flow capability when all feeders are modeled daily with no unwarranted voltage or capacity violations over a consecutive 30-day period.

2.7.4 Calculation Approach

This metric will track and report on the following:
From the time that a substation model is available on a daily basis, for each substation, number of voltage or capacity violations for a consecutive 30-day period, with explanation of any warranted voltage or capacity violations.

In addition, the Companies will report on the number of customers on each feeder benefitting from this technology.

2.7.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

2.7.6 Baseline

The baseline for this metric will start at zero since no feeders have been equipped with this technology. A chart with the total number of feeders installed each year along with a detailed report supporting the chart will be provided to support the tracking of this metric.

2.8 CONTROL FUNCTIONS IMPLEMENTED BY CIRCUIT (VVO, AUTO RECONFIGURATION)

2.8.1 Type

Statewide Performance Metric

2.8.2 Objective

This metric will show the progress in the ADMS investment by tracking the control functions implemented at the circuit level as well as the number of customers affected by the technology on each feeder. This metric will support the objective of optimizing system performance and more specifically minimize electrical losses and improve reliability.

2.8.3 Assumptions

A control function will be defined as the ability for the DMS to automatically issue command to field devices based on real time system condition, and a circuit will be included in this metric when all devices defined as "fully automated" can be automatically controlled.

2.8.4 Calculation Approach

This metric will track and report on the following:

- Circuits with control function implemented
- Type of control function implemented

In addition, the Companies will report on the number of customers on each feeder affected by this technology.

2.8.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

2.8.6 Baseline

The baseline for this metric will start at zero since the specific control functions laid out as part of the Companies' respective GMPs have never been deployed. A table outlining the details behind the control functions implemented at the circuit level will be provided to support the tracking of this metric.

2.9 NUMBERS OF CUSTOMERS THAT BENEFIT FROM GMP FUNDED DISTRIBUTION AUTOMATION DEVICES

2.9.1 Type

Statewide Performance Metric

2.9.2 Objective

This metric will show the progress in the Distribution Automation investment by tracking the numbers of customers that have benefitted from the installation of Distribution Automation devices. This metric will support the objective of optimizing system performance and more specifically reduce the duration and number of customers impacted by outage events. These investments will also allow for a reduction in manual switching operations, reduce operations cost and potentially defer capital upgrades with enhanced flexibility to shift load.

2.9.3 Assumptions

A customer will benefit from distribution automation when their automated zone size is reduced.

2.9.4 Calculation Approach

This metric will track and report on the following:

Circuit number
Number of customers impacted

2.9.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

2.9.6 Baseline

The baseline for this metric will start at zero since this will be tracking only the customers that benefit from GMP investments. A table with the type of device, circuit number where installed and number of customers benefitted will be provided to support the tracking of this metric.

2.10 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS' EFFECT ON OUTAGE DURATIONS

2.10.1 Type

Statewide Performance Metric

2.10.2 Objective

This metric will compare the experience of customers on GMP DA-enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how DA can reduce the duration of outages.

2.10.3 Assumptions

Outages and their impact are typically situational in nature. The DA solutions must be capable of performing intended actions in under the one-minute threshold set by the Department. There may be circumstances where more complex FLISR schemes may take longer than one minute, but less than five, to properly locate, isolate and restore an impacted area safely. The circuit must have three years of SAIDI history to be included in the metric. Additionally, numerous factors, such as a Company's tree trimming cycle, weather and vehicular accidents, can impact system reliability, regardless of a Company's grid modernization investments.

2.10.4 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIDI for circuits that have DA enabled in the GMP plan year
- Three-year average circuit level SAIDI covering the years 2015, 2016, and 2017
- Compare the current year circuit SAIDI with the three-year historic average SAIDI of the circuit

AVERAGE (‘CKAIDI 2015’+’ CKAIDI 2016’+’ CKAIDI 2017’) - ‘CKAIDI Year n’ = if greater than 0, positive impact.

2.10.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

2.10.6 Baseline

The pre-investment baseline of a static three-year average circuit level SAIDI in 2015, 2016, and 2017 shall be provided for each feeder within the service territory. Additionally, the baseline shall be provided with and without Excludable Major Events[4] along with a summary of the main causes of outages on each feeder. The metric will use the circuit three-year SAIDI covering the years 2015-2017 average as the baseline. It will compare the SAIDI results of the plan year to the circuit’s 2015-2017 three-year historic average.

2.11 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS’ EFFECT ON OUTAGE FREQUENCY

2.11.1 Type

Statewide Performance Metric

2.11.2 Objective

This metric will compare the experience of customers on DA-enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how DA can reduce the frequency of outages.

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[4] The Department has defined an “Excludable Major Event” as a major interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned interruption of service to fifteen percent or more of an Electric Company’s total customers in its entire service territory; or (3) the event was a result of the failure of another company’s transmission or power supply system. D.P.U. 12-120-D, §I.B (2015). An interruption event caused by extreme temperature condition is not an Excludable Major Event. Id.

2.11.3 Assumptions

Outages and their impact are typically situational in nature. The DA solutions must be capable of performing intended actions in under the one-minute threshold set by the Department. There may be circumstances where more complex FLISR schemes may take longer than one minute, but less than five, to properly locate, isolate and restore an impacted area safely. The circuit must have three years of SAIFI history to be included in the metric.

2.11.4 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIFI for circuits that have DA enabled in the GMP plan year
- Three-year average circuit level SAIFI covering the years 2015, 2016, and 2017
- Compare the current year circuit SAIFI with the three-year historic average SAIFI of that circuit

AVERAGE (‘CKAIFI 2015’+’ CKAIFI 2016’+’ CKAIFI 2017’) - ‘CKAIFI Year n’ = if greater than 0, positive impact.

2.11.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

2.11.6 Baseline

The pre-investment baseline of a static three-year average circuit level SAIFI in 2015, 2016, and 2017 shall be provided for each feeder within the service territory. Additionally, the baseline shall be provided with and without Excludable Major Events along with a summary of the main causes of outages on each feeder. The metric will use the circuit three-year SAIFI average covering the years 2015-2017 as the baseline for this metric. It will compare the SAIFI results of the GMP plan year to the circuit’s 2015-2017 three-year historic average.

2.12 VVO RELATED VOLTAGE COMPLAINTS PERFORMANCE METRIC AND BASELINE

2.12.1 Type of Metric

Statewide Performance Metric

2.12.2 Objective

The primary focus of the VVO investments is to manage circuit voltages at a lower threshold while maintaining minimum voltage service requirements for all customers on a substation and circuit. Since VVO will be actively managing voltages, there is a desire to track and report on the potential for the introduction of VVO-related voltage complaints. While VVO is not an active solution in use by the Companies today in Massachusetts, there may be historical low voltage causes that exist outside of a customer's service connection and equipment. Certain voltage issues, such as those that are ultimately determined to have been caused by customer-owned equipment, will not be mitigated by the Companies' VVO investments. The Companies will measure the change in voltage complaints following deployment of VVO technology to determine the impact relative to a pre-deployment baseline.

2.12.3 Assumptions

Prior to the requirement to track and report on whether VVO investments could potentially contribute to customer voltage complaints, there was never a need for the Companies to track customer voltage complaints in this manner. For instance, in some cases large commercial and industrial ("C&I") customers' voltage complaints were processed through their customer account executives and were not necessarily logged in the Companies' work management systems: thus, there is no data as to the cause of the voltage issue that gave rise to the complaint. While residential customer voltage complaints were logged in the respective systems, given that VVO is a new investment the Companies cannot reasonably associate these historical complaints as being caused or impacted by VVO investments. In an effort to develop a baseline for this metric, the Companies must manually review the available records to determine the cause and remedy of the voltage issue that led to the customer complaint.

Going forward, the Companies intend to specifically track customer voltage complaints to determine if VVO investments led to the voltage condition giving rise to the customer complaint. Eversource currently has a tracking and reporting process in its Western Massachusetts ("WMA") service territory that enables it to capture and categorize the necessary data related to these voltage complaints. Eversource will expand this process into its Eastern Massachusetts ("EMA") service territory in the near-term to ensure that all relevant data related to the impact of VVO investments on customer voltage complaints is tracked and reported. Unitil currently tracks customer voltage complaints in its Customer Information System ("CIS") and plans to revise the system coding to better capture the data necessary to determine if a voltage issue was impacted by VVO investments. National Grid is currently exploring system and process improvements and enhancements to ensure it is able to track the necessary data on these customer complaints.

Given the lack of consistent and comprehensive data as to whether a customer's voltage complaint was influenced by VVO investments, the Companies propose to utilize all customer voltage complaints received in 2015, 2016 and 2017 to develop the baseline for this performance metric. Additionally, since the compilation of the voltage complaints is a significant manual process, the Companies propose, for the 2022-2025 GMPs, to utilize the following circuits to establish the initial baseline for this performance metric.

Eversource – In its 2018-2020 GMP plans, Eversource will deploy VVO on circuits in Western MA. As previously mentioned, there was a voltage complaint tracking system in Western MA so Eversource will establish a baseline based on the information included in the Western MA tracking system and report on the Western MA performance. There are no VVO investments planned in Eastern MA during 2018-2020. Eversource will incorporate Eastern MA in its baseline, tracking and reporting process in 2021 for the next four-year plan (2022-2025).

Unitil – Under its approved GMP, Unitil intends to install VVO investments on all of the circuits in its service territory. For this performance metric, Unitil proposes to utilize all of its circuits in establishing the baseline

National Grid – National Grid proposes, as an initial baseline, to use the 16 feeders on which it intends to install VVO investments under its 2018-2021 GMP. National Grid is targeting larger circuits in its service territory, that serve approximately 1000 customers or more. National Grid will, following its development and implementation of system and process improvements and enhancements to track these customer complaints and the relevant data, incorporate the remainder of the GMP circuits targeted as VVO/CVR in its service territory into the baseline for this performance metric for the 2022-2025 GMP.

Eversource and National Grid propose to update the baseline for this metric with respect to the 2022-2025 GMPs to include all GMP circuits targeted as VVO/CVR circuits within their respective service territories.

2.12.4 Calculation Approach

This metric will track and report on the following:

- Quantity of voltage complaints for the current year that are deemed caused by VVO voltage management by circuit for circuits that will have VVO installed.
- Three-year average of all voltage complaints by circuit covering the years 2015, 2016, and 2017

- Compare the current year quantity of voltage complaints with the three-year historic average

AVERAGE (‘Voltage Complaints 2015’+ ‘Voltage Complaints 2016’ + ‘Voltage Complaints 2017’) = Voltage Complaint Baseline

2.12.5 Organization of Result

The baseline voltage complaints and the annual VVO related voltage complaints (once VVO investments are active and enabled) will be provided on an annual basis for each circuit. Results will be based upon the results at the end of the calendar year. This will provide the DPU an opportunity to assess the effectiveness of the VVO investments while minimizing the introduction of new customer impact.

2.12.6 Baseline

Utilizing the assumptions discussed above, the Companies will calculate the 2015 through 2017 baseline to use to measure progress under this metric. Given the manual and time-consuming nature of the process to review and compile the customer complaint data, the Companies have determined that this process can be undertaken and completed by June 28, 2019 for incorporation into the Companies’ respective 2018 GMP Annual Reports.

APPENDIX A

Eversource-Specific Performance Metrics

App.A.2.0 EVERSOURCE CUSTOMER OUTAGE METRIC

App.A.2.1 Objective

This metric is intended to measure progress in sectionalizing circuits into protective zones designed to limit outages to customers located within the zone. This metric will measure progress in achieving the grid modernization objective of reducing the impact of outages.

App.A.2.2 Assumptions

A protective zone is defined as the portion of a circuit or circuits that would be isolated by automated backbone devices that will operate automatically to minimize the number of customers affected in the event of an outage.

App.A.2.3 Calculation Approach

For each circuit and for the sum of circuits in eastern and western MA, the metric will track and report on the average zone size in terms of number of customers interconnected in each protective zone.

App.A.2.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

App.A.2.5 Baseline

The Company will provide the average zone size by circuit as of the end of 2017 as the baseline for this metric.

APPENDIX B

Unitil-Specific Performance Metric

App.B.1.0 UNITIL RELIABILITY-RELATED COMPANY-SPECIFIC PERFORMANCE METRIC (CP-1)

App.B.1.0 Type of Metric

Company-Specific Performance Metric

App.B.1.0.1 Objective

The objective of this metric is to track the customer minutes saving per outage on each feeder.

App.B.1.0.2 Assumptions

Outages and their impact are typically situational in nature. However, certain projects are designed to shorten the duration of the outage by improving the initial response to the outage.

App.B.1.0.3 Calculation Approach

The following data will be tracked and reported upon on an individual outage basis:

a. Time of first notification from AMI to OMS
b. Time of first customer call from IVR to OMS
c. Outage duration
d. Feeder and substation level CAIDI for the years 2015, 2016 and 2017

(Time of first notification from AMI to OMS) - (Time of first customer call from IVR to OMS) = number of minutes saved

Number of minutes saved * number of customers affected = customer minutes saved\

AVERAGE (‘Circuit CAIDI 2015’+’ Circuit CAIDI 2016’+’ Circuit CAIDI 2017’) - ‘Circuit CAIDI Year n’ = if greater than 0, positive impact.

App.B.1.0.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

This metric is a study of the overall duration of outages and the number of customer minutes saved based upon grid modernization investments. Data will be provided in a tabular basis by feeder and substation.

App.B.1.0.5 Baseline

The pre-investment baseline of a static three-year average circuit level CAIDI in 2015, 2016, and 2017 shall be provided for each feeder within the service territory. The metric will use the circuit three-year CAIDI average covering the years 2015-2017 as the baseline for this metric. It will compare the CAIDI results of the GMP plan year to the circuit's 2015-2017 three-year historic average.

App.B.1.0.6 Target

Unitil estimated that the grid modernization projects would save on average 5 minutes per outage.

APPENDIX C

National Grid-Specific Performance Metric

App.C.1.0 NATIONAL GRID RELIABILITY-RELATED COMPANY-SPECIFIC PERFORMANCE METRIC

App.C.1.0.1 Type of Metric

Company-Specific Performance Metric

App.C.1.0.2 Objective

This metric is designed to measure the impact of Advanced Distribution Automation (ADA) investments on the customer minutes of interruption (CMI) for main line interruptions.

App.C.1.0.3 Assumptions

The Company intends to rely on existing classifications for mainline interruptions to provide the customer minutes of interruption for both the baseline and to measure the future years CMI for ADA enabled circuits only.

App.C.1.0.4 Calculation Approach

The following information will be tracked and reported for ADA investment at the substation and circuit level where appropriate:

a. Historical customer minutes of interruption for mainline interruptions
b. Calendar year customer minutes of interruption for mainline interruptions

App.C.1.0.5 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year. The metric will be reported upon at the substation and circuit level where ADA is enabled.

App.C.1.0.6 Baseline

The pre-investment baseline of a static three-year average customer minutes of interruption from mainline interruptions in 2015, 2016 and 2017 shall be provided for each feeder within the Company's service territory. The metric will use the circuit three-year CMI average covering the years 2015-2017 as the baseline for this metric. The Company will compare the CMI results of the GMP plan year to the circuit's 2015-2017 three-year historic average.

APPENDIX D

Hosting Capacity Status Reporting

In their initial Grid Modernization Plans ("GMPs"), each Distribution Company described, and in some cases proposed investments related to, the development of hosting capacity maps. D.P.U. 15-120/15-121/15-122, at 42, 86. The Department of Public Utilities (the "Department"), in limiting GMP investments to grid-facing investments, did not authorize the inclusion of hosting capacity map-related investments in the GMPs. Id. at 134, nt. 70. Instead, the Department noted that it would open a separate proceeding into the investigation of cost-effective deployment of customer-facing grid modernization investments. Id. at 135. Accordingly, the Distribution

Companies, following the issuance of the order, shifted their attention and resources to implementing their approved grid modernization investments.

Following the March 14, 2019 technical session on the proposed Grid Modernization Annual Report templates, the Department issued a Memorandum on March 19, 2019 requiring the Distribution Companies to make certain revisions to the grid modernization performance metrics as originally filed on August 15, 2018. As part of the performance metric reporting in the Annual Grid Modernization Reports, the Department also required the Distribution Companies to provide details of their hosting capacity analyses, including the feeder hosting capacity data, for each feeder and substation within their service territories in 2018, 2019, and 2020. Memorandum at 6.

Given that the Distribution Companies' proposed hosting capacity investments were not approved as part of the 2018-2020 GMPs, the Distribution Companies have not progressed hosting capacity analyses as part of this docket. Investments planned over the course of the 2018-2020 GMPs in system visibility and load flow model capabilities are required in order for the Distribution Companies to calculate detailed hosting capacity values. In addition, the Distribution Companies need to work collaboratively with the stakeholders to develop common assumptions and establish load flow and hosting capacity calculation methodologies. This is required so stakeholders that are using the hosting capacity calculations have a common understanding of the approach as they interpret the information provided by the Distribution Companies (see Distribution Companies' responses to DPU-PM-2-1; DPU-PM-2-2 and DPU-PM-3-2).

The Distribution Companies propose to provide the Department and stakeholders with an update on the status of hosting capacity within their respective Grid Modernization Annual Reports. The narrative status update would be supported with a schedule of when each substation and feeder is projected to be ready for a hosting capacity analysis. The Distribution Companies would propose to include the hosting capacity value for those feeders where the models and data is available. The Distribution Companies would also submit a schedule of when they would be able to provide a hosting capacity value for those feeders where the models and data to calculate hosting capacity does not currently exist.

As was clear from the discussion at the March 19, 2019 technical session, the Distribution Companies, the Department, the DOER and other stakeholders are interested in developing robust, comprehensive and useful hosting capacity maps to assist in the interconnection of DG facilities in Massachusetts. To that end, the Distribution Companies look forward to actively participating in the separate proceeding on the deployment of customer-facing grid modernization investments. This separate proceeding will allow for a more comprehensive and efficient approach to developing customer-facing tools and capabilities. Additionally, the Distribution Companies note that the separate proceeding could address the requirement to file heat maps as directed by St. 2018, c. 227.[5]

[5] The Act to Advance Clean Energy, St. 2018, c. 227, §18, requires the Distribution Companies to file an annual electric distribution system resiliency report with the Department, which shall include heat maps that: (i) show the electric load on the electric distribution system, including electric loads during peak electricity demand time periods; (ii) highlight the most congested or constrained areas of the electric distribution system; and (iii) identify areas of the electric distribution system most vulnerable to outages due to high electricity demand, lack of local electric generating resources and extreme weather events.

Exhibit NG-GMP-5

Proposed Metrics for New Investments

In this Exhibit, the Company is proposing Company-specific and statewide performance metrics for its newly-proposed investments.

FERC Order No. 2222 Customer Participation Metric

Type
Statewide Performance Metric

Objective
This metric will demonstrate the number of National Grid customers (*customer count* and *total kilowatt (kw) of DER*) participating in the DER aggregation models in ISO-NE resulting from FERC O2222. The Company's investments related to FERC O2222 included in this filing should help improve market access for DER aggregations by improving the ease and speed of certain distribution utility functions critical to FERC O2222 including those related to the DER aggregation registration and review, metering and settlement, and operational coordination processes. The pace and scale of wholesale market participation by DER aggregations, however, will be dependent on a variety of external factors beyond distribution utility control that may shape the economic viability of market participation.

Assumptions
Reporting information for this metric assumes that ISO-NE's proposed compliance filing for FERC O2222 is submitted to FERC, approved by FERC, and implemented as operational in ISO-NE. For years prior to implementation all values for this metric will be zero or considered non-applicable.

Calculation Approach
This metric will track and report on the following:

At the end of the calendar year how many (1) customers and (2) associated kw of DER are enrolled as part of aggregated DER resources in the ISO-NE wholesale market.

Organization of Results
This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

Baseline
The baseline for this metric will start at zero since ISO-NE has not implemented the new DER aggregation participation models that will result from FERC O2222. A chart with the total number of customer participants and associated kw of DER enrolled each year will be provided to support the tracking of this metric.

DERMS SOFTWARE

Type
Statewide Performance Metric

Objective
This metric is intended to track and monitor the execution of the Distributed Energy Resource Management System ("DERMS") through the number of sites with DER that are managed by DERMS and the quantity of dispatchable kilowatts ("kW") that the utility can dispatch

Assumptions
Distributed Energy Resources ("DER") nameplate and operational parameters are provided by customers to the Company in a timely manner.

DER assets will be added to the DERMs database via direct I.T. platform interface or manual entry.

The Company intends to include existing Demand Response ("DR") customers and their specific use-cases into the DERMS.

- All prior DR data will be rebaselined to zero. See "Baseline" section below.
- It is currently unknown if the DERMS functionality can match the existing DR customer use cases.

Calculation Approach
The following metrics will be used to monitor the participation rate and dispatched kilowatts for DER assets.

- ***Number of Participating Sites:*** This metric will be a direct number of sites being managed by DERMS.
- ***Total kW of Dispatchable DER that is managed by DERMS:*** This metric will be a number of kW nameplate capacity of DER that are managed by DERMS for a given period.
- ***Number of Instances[1] Sites are Dispatched:*** This metric will be a direct number of instances, per site, that are dispatched as part of the DERMS program, for a given period.

Organization of Results
This data will be provided on an annual basis with the Grid Modernization Annual report, for the year prior. Data will be arranged by the following:

- ***Number of Participating Sites:*** The number of participating sites will be presented by feeder.
- ***Total kW of Dispatchable DER that is managed by DERMS:*** A single kW value will be provided for total DER managed by DERMS.

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[1] "Instances" is to mean the number of days in a given period that a site received any centrally communicated dispatch by DERMS.

- ***Number of Instances Sites are Dispatched:*** A direct number will be provided, for each specific site, by feeder.

Baseline

Because the Company has not had the ability to allow customers to participate in this type of DER system management before, the baselines for these metrics will be zero. This is inclusive of any existing DR assets that will be migrated into the DERMS from the Company's existing Demand Response Management System (DRMS).

Increase in Feeders with Advanced Short-Term Load Forecasting Capabilities

Type
Company-Specific Performance Metric

Objective
This metric will demonstrate the progress in the Advanced Short-Term Load Forecasting ("ASTLF") investment by tracking the number of feeders that the Company has deployed advanced short-term load forecast capabilities. This metric will support the objective of optimizing system performance and more specifically improving grid visibility, improving reliability and integrating distributed energy resources. ASTLF capabilities give system operators increased visibility on near-term system loading conditions including potential impacts from DER.

Assumptions
A feeder will be assumed to have ASTLF capability when the feeder or its associated substation has an advanced short-term load forecast model developed and trained where a short-term forecast can be generated to support distribution system operations.

Calculation Approach
This metric will track and report on the following:
From the time that a feeder or substation forecast model is available on a daily basis to generate a short-term hourly load forecast.

Organization of Results
This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

Baseline
The baseline for this metric will start at zero since no feeders have been equipped ASTLF capabilities. A chart with the total number of feeders with ASTLF capabilities each year along with a detailed report supporting the chart will be provided to support the tracking of this metric.

DERMS Investigation

Type
Company-Specific Performance Metric

Objective
This metric will demonstrate the progress in the Distributed Energy Resource Management System ("DERMS") Investigation investment by tracking the progression of scheduled milestones in the Company's proposal for this investment. This metric is designed to demonstrate achievement of milestones and tasks completed in driving towards the Company's preparation to implement DERMS 2.0 and the DERMS Platform that is currently anticipated to start in CY25.

Assumptions
It is assumed that there are no significant changes in need or reprioritization of DER management capabilities identified during the DERMS Investigation that may shift the order or effort required for the major tasks.

Calculation Approach
This metric will track and report on the following:
From the date that a major task is completed to when it is scheduled to be completed in the proposed DERMS Investigation project schedule of this grid modernization plan.

Organization of Results
This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

Baseline
The baseline for this metric will be based on the proposed DERMS Investigation project schedule in this grid modernization plan.

Massachusetts Electric Company and
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July 1, 2021
H.O. ________________

Exhibit NG-GMP-6

Grid Modernization Provision Tariff, M.D.P.U. No. 1469 (clean)

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GRID MODERNIZATION FACTOR

1.0 APPLICABILITY

This Grid Modernization Factor ("GMF") tariff provides for the recovery of incremental costs associated with the Company's Grid Modernization Plan ("GMP") approved by the Department of Public Utilities (the "Department"). To be eligible for recovery, GMP costs must: (1) be preauthorized by the Department; (2) be incremental relative to the Company's current investment practices or new types of technology for capital investments; (3) be incremental to those costs that the Company currently recovers through its base distribution rates for operation and maintenance ("O&M") expenses and solely attributable to preauthorized grid modernization investments; (4) be prudently incurred; (5) have aggregate total expenditures for preauthorized Eligible GMP Projects less than the four-year expenditure cap determined by the Department; and (6) be recorded as in-service by December 31 of each GMP Investment Year.

The Company's rates for retail Delivery Service are subject to adjustment to reflect the operation of this GMF tariff. The Grid Modernization Factor ("GMF"), as defined herein, shall be applied to all retail delivery service kilowatt-hours ("kWhs") as determined in accordance with the provisions of Section 3.0 below. The GMF shall be determined annually by the Company, subject to the Department's review and approval. The operation of this GMF tariff is subject to Chapter 164 of the General Laws.

2.0 DEFINITIONS

2.1 <u>Accumulated Deferred Income Taxes (ADIT)</u> means the accumulated deferred income taxes associated with cumulative Eligible GMP Investments as of the end of the respective GMP Investment Year. For the year in which the Eligible GMP Investment was placed into service, the accumulative deferred income taxes will be determined on a monthly basis. The accumulated deferred income taxes for subsequent years shall be calculated based upon the average the beginning and ending calendar year balances.

2.2 <u>Accumulated Reserve for Depreciation (ARD)</u> means the Accumulated Reserve for Depreciation, including net salvage, associated with cumulative Eligible GMP Investments as of the end of the respective GMP Investment Year. For the year in which the Eligible GMP Investment was placed into service, the Accumulated Reserve for Depreciation will be determined on a monthly basis. The Accumulated Reserve for Depreciation for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

2.3 <u>Allowed O&M Expense (O&M)</u> is the incremental O&M expense that is incurred by the Company as a result of implementing its GMP and is solely attributable to preauthorized grid modernization investments, including incremental GMP development and evaluation costs, the cost of which is not being recovered in base distribution rates or through another cost recovery mechanism. Eligible O&M costs are the actual monthly GMP-related O&M expenses incurred in the GMP Investment Year prior to the Recovery Year. Allowed O&M Expense will exclude all overhead and burdens O&M expenses, including pension and post-retirement benefits other than pension costs recovered through any other reconciling mechanism.

2.4 Depreciation Expense (DEPR) is the annual depreciation expense associated with the average annual cumulative Eligible GMP Investments placed into service through the end of the calendar year prior to the Recovery Year. For the year during which the Eligible GMP Investment is placed into service, the Company shall calculate depreciation expense for use in the GMP Revenue Requirement by (1) dividing the annual depreciation accrual rates determined in the Company's most recent base distribution rate case by 12, and (2) applying the resulting rate to the average monthly plant balances during the year. Depreciation expense for subsequent years may be calculated based on the average of the beginning and end of year plant balances.

2.5 Eligible GMP Investments are the cumulative capitalized costs of Eligible GMP Projects recorded as in-service, including net salvage, and are used and useful at the end of the GMP Investment Year that is prior to the GMP Recovery Year.

2.6 Eligible GMP Project is a project contained in the Company's GMP and preauthorized by the Department to be eligible for cost recovery as a project which contributes towards achieving the Department's grid modernization objectives to: (1) optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing; (2) optimize system demand by facilitating consumer price-responsiveness; and (3) interconnect and integrate distributed energy resources.

2.7 GMF is the Grid Modernization Factor that recovers the annual GMP Revenue Requirement approved by the Department.

2.8 GMP is the Company's five-year Grid Modernization Plan which includes a four-year short-term investment plan consisting of Eligible GMP Projects, plus a five-year strategic plan outlining how the Company intends to meet the Department's grid modernization objectives.

2.9 GMP Investment Year is the annual period beginning on January 1 and ending on December 31.

2.10 Recovery Year is the 12-month period for which the GMF is in effect beginning on May 1 and ending on April 30 of each year.

2.11 GMP Revenue Requirement is the revenue requirement associated with GMP plant-in-service for each GMP Investment Year prior to the Recovery Year, plus Allowed O&M Expense. For the year in which an Eligible GMP Investment is placed into service, the GMP Revenue Requirement will be calculated on a monthly basis. The GMP Revenue Requirement for subsequent years shall be calculated based upon the average of the

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beginning and ending calendar year balances. The GMP Revenue Requirement will be calculated to recover (1) the monthly revenue requirement for Eligible GMP Investments placed into service in the GMP Investment Year immediately prior to the Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the GMP Investment Year immediately prior to the Recovery Year, for cumulative Eligible GMP Investments placed into service in GMP Investment Years two years prior to the Recovery Year; and (3) Allowed O&M Expense.

2.12 Gross Plant Investments are the capitalized costs of Eligible GMP Investments recorded on the Company's books for Eligible GMP Investments. Actual capitalized cost of Eligible GMP Investments shall include applicable overhead and burden costs subject to the test provided in Section 4.0.

2.13 Pre-Tax Rate of Return (PTRR) shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period for which the GMP Revenue Requirement is calculated.

2.14 Property Tax Expense (PTE) means the property taxes calculated based on Eligible net GMP Investments multiplied by the Property Tax Rate. Property taxes will be excluded in the GMP Revenue Requirement in the first Recovery Year following the GMP Investment Year in which the eligible taxable plant went into service. Property taxes will be included in the GMP Revenue Requirement beginning in the second Recovery Year at 50% of the annual property tax amount. In subsequent years, the GMP Revenue Requirement will reflect a full year of property taxes.

2.15 Property Tax Rate is the Company's composite property tax rate determined in the Company's most recent base distribution rate case, calculated as the ratio of total annual property taxes paid to total taxable net plant in service.

2.16 Rate Base (RB) is the investment value upon which the Company is permitted to earn its authorized rate of return.

3.0 GRID MODERNIZATION FACTOR ("GMF")

3.1 Rate Formula

$$GMF_c = \frac{(GMR + PPRA) \times DRA_c}{FkWh_c}$$

Where:

c — Designates a separate factor for the following rate classes: R-1/R-2, G-1, G-2, G-3, and Streetlighting.

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GMF_c The Grid Modernization Factor, by rate class, as defined in Section 2.7.

GMR The GMP Revenue Requirement as defined in Section 2.11.

PPRA The Past Period Reconciliation Amount defined as the difference between (a) the amount authorized to be recovered through the prior year's GMFs as approved by the Department and (b) the actual revenue billed through the applicable GMFs. Interest calculated on the average monthly balance using the customer deposit rate, as outlined in 220 CMR 26.09, shall also be included in the PPRA.

DRA_c The Distribution Revenue Allocator representing the percentage of final revenue requirement allocated to each rate class as determined in the Company's most recent general rate case as follows:

Rate R-1/R-2	57.7%
Rate G-1	12.9%
Rate G-2	11.9%
Rate G-3	16.9%
Streetlighting	0.6%

$FkWh_c$ The forecasted kWh to be delivered to the Company's retail delivery service customers.

3.2 Request for GMFs

The Company shall submit annually to the Department its proposed GMFs by March 15 to become effective for usage on and after May 1.

3.3 Application of GMFs on Customer Bills

For billing purposes, the GMF will be included with the distribution kWh charge on customers' bills.

4.0 OVERHEAD AND BURDEN ADJUSTMENTS

For purposes of GMF calculations, the actual overhead and burdens shall be reduced to the extent that actual O&M overhead and burdens in a given year are less than the amount included in base distribution rates as determined in the Company's most recent base distribution rate case. Such reduction shall be the difference between the actual O&M overhead and burdens and the amount included in base distribution rates.

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In addition, the percentage of capitalized overhead and burdens assigned to GMF projects shall be set equal to the ratio of GMF to non-GMF direct costs in any given year.

5.0 FILINGS WITH THE DEPARTMENT

5.1 GMP Term Filing.

The Department preauthorized the Company's first short term investment plan Eligible GMP Projects and spending cap in D.P.U. 15-120 (2018), establishing four years of GMP spending for the GMP Investment Years 2018 through 2021 (first authorization term) and the second short term investment plan Eligible GMP Projects and spending cap in D.P.U. 21-81 (2021), establishing four years of GMP spending for the GMP Investment Years 2022 through 2025 (second authorization term). The operation of this GMF tariff is applicable to Eligible GMP Investment and Allowed O&M Expense associated with the first two GMP terms (2018 through 2021, and 2022 through 2025).

5.2 Annual GMP Cost Recovery Filing.

The annual GMP cost recovery filing shall be submitted to the Department by March 15 and include, but not be limited to:

(1) Full project documentation of all Eligible GMP Projects' capital investment recorded as in-service during the Prior GMP Investment Year and documentation of Allowed O&M Expense, with narrative providing justification that the costs meet the cost recovery eligibility requirements in Section 1.0;

(2) Supporting documentation demonstrating that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable);

(3) Any cost variances as defined in the Company's capital authorization policies;

(4) A demonstration that the proposed factors are calculated appropriately;

(5) Bill impacts; and

(6) Demonstration that aggregate total of expenditures for preauthorized Eligible GMP Projects is under the four-year expenditure cap determined by the Department. This information shall also be included in the Term Report indicated below.

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5.3 Grid Modernization Annual Report.

The Grid Modernization Annual Report shall be submitted to the Department by April 1 following the completion of the GMP Investment Year.

5.4 Grid Modernization Term Report.

The Grid Modernization Term Report shall be submitted to the Department by April 1 following the completion of the four-year short term investment plan.

Exhibit NG-GMP-7

Grid Modernization Provision Tariff, M.D.P.U. No. 1469 (redlined)

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1.0 APPLICABILITY

This Grid Modernization Factor ("GMF") tariff provides for the recovery of incremental costs associated with the Company's Grid Modernization Plan ("GMP") approved by the Department of Public Utilities (the "Department"). To be eligible for recovery, GMP costs must: (1) be preauthorized by the Department; (2) be incremental relative to the Company's current investment practices or new types of technology for capital investments; (3) be incremental to those costs that the Company currently recovers through its base distribution rates for operation and maintenance ("O&M") expenses and solely attributable to preauthorized grid modernization investments; (4) be prudently incurred; (5) have aggregate total expenditures for preauthorized Eligible GMP Projects less than the ~~three~~four-year expenditure cap determined by the Department; and (6) be recorded as in-service by December 31 of each GMP Investment Year.

The Company's rates for retail Delivery Service are subject to adjustment to reflect the operation of this GMF tariff. The Grid Modernization Factor ("GMF"), as defined herein, shall be applied to all retail delivery service kilowatt-hours ("kWhs") as determined in accordance with the provisions of Section 3.0 below. The GMF shall be determined annually by the Company, subject to the Department's review and approval. The operation of this GMF tariff is subject to Chapter 164 of the General Laws.

2.0 DEFINITIONS

2.1 Accumulated Deferred Income Taxes (ADIT) means the accumulated deferred income taxes associated with cumulative Eligible GMP Investments as of the end of the respective GMP Investment Year. For the year in which the Eligible GMP Investment was placed into service, the accumulative deferred income taxes will be determined on a monthly basis. The accumulated deferred income taxes for subsequent years shall be calculated based upon the average the beginning and ending calendar year balances.

2.2 Accumulated Reserve for Depreciation (ARD) means the Accumulated Reserve for Depreciation, including net salvage, associated with cumulative Eligible GMP Investments as of the end of the respective GMP Investment Year. For the year in which the Eligible GMP Investment was placed into service, the Accumulated Reserve for Depreciation will be determined on a monthly basis. The Accumulated Reserve for Depreciation for subsequent years shall be calculated based upon the average of the beginning and ending calendar year balances.

2.3 Allowed O&M Expense (O&M) is the incremental O&M expense that is incurred by the Company as a result of implementing its GMP and is solely attributable to preauthorized grid modernization investments, including incremental GMP development and evaluation costs, the cost of which is not being recovered in base distribution rates or through another cost recovery mechanism. Eligible O&M costs are the actual monthly GMP-

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related O&M expenses incurred in the GMP Investment Year prior to the Recovery Year. Allowed O&M Expense will exclude all overhead and burdens O&M expenses, including pension and post-retirement benefits other than pension costs recovered through any other reconciling mechanism.

2.4 Depreciation Expense (DEPR) is the annual depreciation expense associated with the average annual cumulative Eligible GMP Investments placed into service through the end of the calendar year prior to the Recovery Year. For the year during which the Eligible GMP Investment is placed into service, the Company shall calculate depreciation expense for use in the GMP Revenue Requirement by (1) dividing the annual depreciation accrual rates determined in the Company's most recent base distribution rate case by 12, and (2) applying the resulting rate to the average monthly plant balances during the year. Depreciation expense for subsequent years may be calculated based on the average of the beginning and end of year plant balances.

2.5 Eligible GMP Investments are the cumulative capitalized costs of Eligible GMP Projects recorded as in-service, including net salvage, and are used and useful at the end of the GMP Investment Year that is prior to the GMP Recovery Year.

2.6 Eligible GMP Project is a project contained in the Company's GMP and preauthorized by the Department to be eligible for cost recovery as a project which contributes towards achieving the Department's grid modernization objectives to: (1) optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing; (2) optimize system demand by facilitating consumer price-responsiveness; and (3) interconnect and integrate distributed energy resources.

2.7 GMF is the Grid Modernization Factor that recovers the annual GMP Revenue Requirement approved by the Department.

2.8 GMP is the Company's five-year Grid Modernization Plan which includes a ~~three~~four-year short-term investment plan consisting of Eligible GMP Projects, plus a five-year strategic plan outlining how the Company intends to meet the Department's grid modernization objectives.

2.9 GMP Investment Year is the annual period beginning on January 1 and ending on December 31.

2.10 Recovery Year is the 12-month period for which the GMF is in effect beginning on May 1 and ending on April 30 of each year.

2.11 GMP Revenue Requirement is the revenue requirement associated with GMP plant-in-service for each GMP Investment Year prior to the Recovery Year, plus Allowed O&M Expense. For the year in which an Eligible GMP Investment is placed into service, the GMP Revenue Requirement will be calculated on a monthly basis. The GMP Revenue Requirement for subsequent years shall be calculated based upon the average of the

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beginning and ending calendar year balances. The GMP Revenue Requirement will be calculated to recover (1) the monthly revenue requirement for Eligible GMP Investments placed into service in the GMP Investment Year immediately prior to the Recovery Year; (2) the average annual revenue requirement for the calendar year ending December 31 of the GMP Investment Year immediately prior to the Recovery Year, for cumulative Eligible GMP Investments placed into service in GMP Investment Years two years prior to the Recovery Year; and (3) Allowed O&M Expense.

2.12 Gross Plant Investments are the capitalized costs of Eligible GMP Investments recorded on the Company's books for Eligible GMP Investments. Actual capitalized cost of Eligible GMP Investments shall include applicable overhead and burden costs subject to the test provided in Section 4.0.

2.13 Pre-Tax Rate of Return (PTRR) shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period for which the GMP Revenue Requirement is calculated.

2.14 Property Tax Expense (PTE) means the property taxes calculated based on Eligible net GMP Investments multiplied by the Property Tax Rate. Property taxes will be excluded in the GMP Revenue Requirement in the first Recovery Year following the GMP Investment Year in which the eligible taxable plant went into service. Property taxes will be included in the GMP Revenue Requirement beginning in the second Recovery Year at 50% of the annual property tax amount. In subsequent years, the GMP Revenue Requirement will reflect a full year of property taxes.

2.15 Property Tax Rate is the Company's composite property tax rate determined in the Company's most recent base distribution rate case, calculated as the ratio of total annual property taxes paid to total taxable net plant in service.

2.16 Rate Base (RB) is the investment value upon which the Company is permitted to earn its authorized rate of return.

3.0 GRID MODERNIZATION FACTOR ("GMF")

3.1 Rate Formula

$$GMF_c = \frac{(GMR + PPRA) \times DRA_c}{FkWh_c}$$

Where:

c Designates a separate factor for the following rate classes: R-1/R-2, G-1, G-2, G-3, and Streetlighting.

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GMF_c The Grid Modernization Factor, by rate class, as defined in Section 2.7.

GMR The GMP Revenue Requirement as defined in Section 2.11.

PPRA The Past Period Reconciliation Amount defined as the difference between (a) the amount authorized to be recovered through the prior year's GMFs as approved by the Department and (b) the actual revenue billed through the applicable GMFs. Interest calculated on the average monthly balance using the customer deposit rate, as outlined in 220 CMR 26.09, shall also be included in the PPRA.

DRA_c The Distribution Revenue Allocator representing the percentage of final revenue requirement allocated to each rate class as determined in the Company's most recent general rate case as follows:

Rate R-1/R-2	57.7%
Rate G-1	12.9%
Rate G-2	11.9%
Rate G-3	16.9%
Streetlighting	0.6%

$FkWh_c$ The forecasted kWh to be delivered to the Company's retail delivery service customers.

3.2 Request for GMFs

The Company shall submit annually to the Department its proposed GMFs by March 15 to become effective for usage on and after May 1.

3.3 Application of GMFs on Customer Bills

For billing purposes, the GMF will be included with the distribution kWh charge on customers' bills.

4.0 OVERHEAD AND BURDEN ADJUSTMENTS

For purposes of GMF calculations, the actual overhead and burdens shall be reduced to the extent that actual O&M overhead and burdens in a given year are less than the amount included in base distribution rates as determined in the Company's most recent base distribution rate case. Such reduction shall be the difference between the actual O&M overhead and burdens and the amount included in base distribution rates.

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In addition, the percentage of capitalized overhead and burdens assigned to GMF projects shall be set equal to the ratio of GMF to non-GMF direct costs in any given year.

5.0 FILINGS WITH THE DEPARTMENT

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5.3 Grid Modernization Annual Report.

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5.4 Grid Modernization Term Report.

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