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

Grid Modernization Plan
Annual Report Calendar Year 2019

D.P.U. 15-120

April 1, 2020

Submitted to:
Massachusetts Department of
Public Utilities

Table of Contents

I. Introduction

On May 10, 2018, the Department of Public Utilities (the "Department") issued a decision (the "Order") approving in part the grid modernization plans ("GMPs") for Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or "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 dockets D.P.U. 15-120, 15-121 and 15-122. In the Order, the Department pre-authorized grid-facing investments over three-years (2018-2020) for National Grid, Eversource and Unitil, respectively, and adopted a three-year (2018-2020) regulatory review construct for preauthorized Grid Modernization investments. Order at 106-115. The Order provided that the Companies will submit GMPs every three years, which will be addressed in separate proceedings, and that the Companies must submit "Grid Modernization Term Reports" at the end of each three-year term, which document performance during the term. Id. at 111-112. The Order also provided that the Companies must submit "Grid Modernization Annual Reports" to document performance during the applicable year and that these will be docketed for informational purposes only, but the Department may formally investigate a company's performance during the term of the plan if the Department determines this is warranted. Id. These Grid Modernization Annual Reports are due on April 1 of the year following the first and second plan years. Id. at 114.

The Department has established the outline/table of contents to be included in the annual report. D.P.U. 15-120/15-121/15-122, Hearing Officer Memorandum (March 29, 2019). The Department has approved the metrics to be reported on in the annual reports. D.P.U. 15-120/15-121/15-122, Stamp Approval (July 25, 2019). The Department also has adopted templates to be completed and included with the annual reports. D.P.U. 15-120-C/15-121-C/15-122-C (December 6, 2019). This filing is National Grid's second Grid Modernization Annual Report, which contains the narrative documenting the Company's performance on its Grid Modernization Plan for the time period January 1, 2019 through December 31, 2019 ("Report") and is accompanied by the templates the Department has approved.

Key elements of the Department's Order approving in part the GMPs, and which are reflected in this Report, include:

- Objectives: The Department refined their grid modernization objectives to place additional focus on improved access to the distribution system planning process, in order to ensure a cleaner, more efficient and reliable grid.

- Grid-Facing Investments: The Department approved National Grid's proposed grid-facing investments and preauthorized $82 million in spending for these investments over three years from January 1, 2018 through December 31, 2020. The Department held that these investments may be treated as incremental to current investments if a "primary purpose" of the proposed investment is to accelerate progress in achieving the grid modernization objectives.

- Customer-Facing Investments: The Department did not pre-authorize: smart meters and Advanced Metering Infrastructure ("AMI") back office infrastructure; customer load management; communications and information/operational technologies related to AMI; cybersecurity related to customer-side investments; workforce training and asset management; marketing, education and outreach; and project management office.

- Cost Recovery: The Department approved a short-term targeted cost recovery mechanism, the Grid Modernization Factor ("GMF"), for pre-authorized grid modernization investments. This is a reconciling mechanism that: (1) includes both capital and operations and maintenance ("O&M") costs; (2) includes incremental grid modernization costs that are prudently incurred, in service, and used and useful to customers; and (3) applies to investments made in the first six years of the GMPs only.

A. Progress Toward 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 Companies' GMPs, and described the objectives as follows:

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.[1]

National Grid's GMP contained a comprehensive suite of investments and initiatives that will modernize the Company's infrastructure 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. National Grid reviewed the approved elements of the GMP in the context of the revised objectives and aligned and revisited the plan elements in order to ensure progress towards the revised grid modernization objectives during calendar year 2018. In calendar year 2019 National Grid developed detailed plans for each investment area and continued executing those plans through the end of 2019.

With respect to optimizing system performance, the Company completed planning and engineering efforts for the selection of locations for both feeder monitors and advanced distribution automation. Once locations were identified and selected, the investments were progressed to our engineering design organization. The Company also completed analysis and identification of circuits to deploy Volt/VAR Optimization ("VVO"), which will help to optimize system demand. Once circuits were identified and selected, the investments were progressed to our engineering design organization.

National Grid completed a strategic assessment of the telecommunications information technology/operational technology ("IT/OT") approach for connecting, communicating and operating grid devices. As a component of the strategy, National Grid identified short term and long-term plans for building the enabling communications necessary to achieve visibility, control and operation of the first term investments.

Lastly, the Company has progressed planning and design of the Advanced Distribution Management System ("ADMS")/Distribution Supervisory Control and Data Acquisition ("DSCADA") platform, which supports all three Grid Modernization objectives. This includes initiation of efforts to perform data clean up and validation of the connected model within our GIS to support ADMS requirements.

---

[1] Previously the Department had included a fourth objective, "improve workforce and asset management," as a stand-alone objective. In the Order the Department determined that this would be eliminated as a stand-alone objective and would be considered within the context of the other three objectives.

B. Summary of Grid Modernization Deployment (Actual v. Planned)

The Company's GMP organized its grid modernization investments into three primary groupings:

(1) field deployments,
(2) enabling infrastructure/initiatives, and
(3) other required components.

Field deployments consist of devices and technology which are interconnected to the distribution system within the Company's service territory. These devices and technology provide benefits directly to the system and to customers, and are the GMP components with significant visibility. Enabling infrastructure is the required back office systems and field devices which enable these field-deployed devices to operate, and enabling initiatives would include the project management office which will help with implementation.

The other required components grouping included metrics and research, development and deployment ("RD&D").

The Company progressed investments across all the approved categories. The plans developed did result in a change in the calendar year 2018 assumptions for planned deployment. The changes resulted in shifting of field device deployment into plan year 2020. In addition, the revised plans for progressing the ADMS/DSCADA and back-office IT infrastructure initiatives resulted in changes to assumptions for development and implementation of these investments. Some of these investments will require a shift to the next three-year plan period.

The Company has provided the summary of planned versus actual deployment of devices as of December 31, 2019 in Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 20-24.

National Grid completed a detailed review and solutions assessment which laid out a five-year deployment effort to implement an ADMS and DSCADA system to support the increased number of distribution devices (including Fault Location, Isolation, and Service Restoration, or "FLISR"; Conservation Voltage Reduction ("CVR")/ VVO, telecommunications and feeder monitors) in the GMP (as well as Distributed Energy Resources, or "DERs") to meet the requirements for grid modernization. The development and implementation effort begin during the 2020 plan year with completion anticipated during the next three-year plan period.

C. Summary of Spending (Actual v. Planned)

The Department approved a budget of up to $82 million in incremental spending for grid-facing investments over three years. The investments' primary purpose must be to accelerate progress in achieving grid modernization objectives and they must be either (1) new types of technology or (2) an increase in the level of investment a company proposes relative to its current investment practices.[2] Incremental O&M expenses must be (1) incremental to the representative level of expenses recovered through rates, and (2) solely attributable to preauthorized grid modernization expenses.[3]

The Company filed its documentation for its incremental operations and maintenance ("O&M") costs for its GMP in CY 2018 of $98,935, in Docket D.P.U. 19-36. Due to the small amount of these costs, they did not generate a Grid Modernization Factor ("GMF") to bill to customers. The Company deferred its request to recover these costs from customers to its next GMF filing on March 15, 2020. The Company included these costs with the costs for CY 2019 for recovery through the GMF that the Company has requested to go into effect beginning May 1, 2020 in D.P.U. 20-31.

The CY 2019 spending includes costs for cybersecurity, ADA, ADMS, Feeder Monitors, VVO, GIS, and telecommunications. The Company has also included costs associated with managing and delivering the portfolio, required change management and the evaluation plan.

The Company is providing the summary of planned versus actual spending as of December 31, 2019 in Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L.

[2] Order at 221-222.

[3] Id.

II. Program Implementation Overview

A. Organizational Changes to Support Program Implementation

The Company established a new organization in August 2018, the Grid Modernization Execution organization, to drive the delivery of the Grid Modernization program. The Company has been actively pursuing the right candidates to fill the organizational needs. This activity is ongoing and will continue into calendar year 2020. The Company has organized delivery of the core grid modernization investments, initiatives and capabilities into the following areas listed below: 1) Physical Infrastructure, 2) Platforms and Advanced Applications, 3) Grid and Network Communications, and 4) Program and Change Management.

To take advantage of grid modernization platform investments across the other jurisdictions in which the Company's affiliates operate, and to leverage synergies across National Grid business units, a central Transformation Office was formed in 2019. ADMS is one of the major initiatives to be managed and delivered by the Transformation Office.

Physical Infrastructure (sensing & operating)

What's included:
- VVO/CVR
- Distribution Automation
- Feeder Monitoring Sensors

Type of work:
- Primarily consists of installation and commissioning of new field devices for sensing and automated field operation

Current status of the work:
- Majority of the work is currently between the engineering and construction phase. Primarily delivered by operational groups

Scope of the work:
- Identify investment details in alignment with Grid Mod objectives
- Progress investment sanction
- Manage and support progression of investments
- Develop and deliver training

IT and Cyber involvement:
- IT: Low to Medium
- Cyber: Medium

Responsibilities of Grid Mod team:
- Project Management
- Technical support (engineering)
- Field coordination
- Standards development
- Training

Platform and Advance Applications

What's included:
- ADMS
- DSCADA
- DERMS (future project)

Type of work:
- Upgrade and integrate existing systems and incorporate advanced applications to improve operational performance.

Current status of the work:
- Currently the projects are in the requirement definition phase. Primarily delivered by IS and the Project team

Scope of the work:
- Progress investments through systems development lifecycle
- Develop and deliver change management
- Business process design

IT and Cyber involvement:
- IT: High
- Cyber: High

Responsibilities of Grid Mod team:
- Project Management
- Business requirement
- Technical support (engineering)
- Change management

Grid and Network Communications

What's included:
- TOMS
- DMX
- INOC
- Network Tiers

Type of work:
- The work in this space falls in 3 categories: strategy, market research, and network (IT/OT) investments.

Current status of the work:
- Most of the projects are in the scoping or investigation phase and the development of RFPs.

Scope of the work:
- Identify investment needs in alignment with Grid Mod objectives
- Progress investment sanction
- Manage and support progression of investments

IT and Cyber involvement:
- IT: High
- Cyber: High

Responsibilities of Grid Mod team:
- Strategy development
- Market exploration
- Investment planning
- Coordination with telecom engineering

PMO, Change and Data Management

What's included:
- Project Financial Controls
- Project Management Office
- Data Management
- Regulatory Reporting and Metrics
- Change Management

Type of work:
- Drive successful program delivery in accordance with business management system and project management principles

Current status of the work:
- PMO active with change and data completing resourcing and prioritization

Scope of the work:
- Program PMO
- Change Management strategy and execution
- Data Architecture Design
- Data Analysis and Reporting
- Regulatory Reporting
- Value and Risk Management
- Business Process Definition and Mapping

Responsibilities of Grid Mod team:
- Regulatory filings
- Steer Co and Mgmt reporting
- Program Controls and Assurance
- Business Readiness and Change

B. Cost and Performance Tracking Measures Adopted

The Company has developed protocols and measures for identifying and tracking incremental capital and O&M expenses. The Company has grid modernization-specific work orders to distinguish the preauthorized grid modernization investments within its accounting system. The charges are reviewed on a monthly basis for verification and any charges that are deemed unrelated to the eligible grid modernization investments are reclassified to the appropriate organization.

The Department's Order provides that the Companies must demonstrate that all O&M expenses proposed for recovery through the GMF are: (1) incremental to the representative level of O&M expenses recovered through rates; and (2) solely attributable to preauthorized grid modernization expenses.

This overarching two-prong test has been applied to all O&M expenses sought for recovery, including the two broad categories of: (a) internal O&M labor expenses; and (b) third-party/contractor costs.

The Company also has established its own formal Project Management Office ("PMO") and will drive GMP cost and performance controls through the PMO.

The Company has adopted and provided both infrastructure and performance metrics described later in this Report. The EDCs have also progressed the Evaluation Plan, which will be formally file PY2019 Evaluations and revisions to the Evaluation Plans for future years on April 1, 2020.

C. Project Approval Process: Description and how it is different from process for standard capital investments

The Company recognizes the requirement to maintain grid modernization investments separate from other capital investments, as described in the prior Section. The Company also sought to maintain process efficiencies and alignment with core controls for progressing project approvals. The Company leveraged its existing sanctioning and approval process for capital investments, and applied this process to grid modernization investments as well. This ensures alignment with core controls and visibility of grid modernization investments for proper prioritization.

III. Implementation by Investment Category

A. System Level Narrative by Investment Category

The Department preauthorized the following categories of grid-facing investments for a combined three-year budget of $82 million: (1) VVO; (2) ADA; (3) feeder monitors; (4) communications and IT/OT; and (5) ADMS/SCADA.[4] National Grid's cost estimates for the proposed enabling infrastructure include: (1) a proposed budget of $48.4 million for three years for ADMS/SCADA; and (2) a proposed budget of $1.8 million over three years for communications and IT/OT. Id. at 29, 35. National Grid's cost estimates for the proposed field deployments include: (1) $10.6 million over three years for deployment of VVO; (2) $13.4 million over three years for deployment of ADA; and (3) $8 million over three years for feeder monitors.[5]

These investments and initiatives make progress on the Department's objectives for grid modernization in the following ways:

(i) They will optimize system performance by providing automated outage and restoration notifications, assisting with determining outage locations and damage, and automatically rerouting power during outages in order to minimize the number of customers impacted and the length of outages. The ADA program is specifically designed to significantly reduce the minutes of customers interrupted by automatically re-routing power in a way that the current system is not capable of, and will be deployed on the most high-value feeders.

(ii) They will optimize system demand by creating a more efficient electric system with more real-time monitoring and control, better-managed system voltage and fewer losses. The CVR/VVO program will intelligently switch reactive power and voltage support devices to reduce losses, improve power factor and reduce demand in a way that the current system is unable to do. This program is designed to provide peak and demand savings to customers, without them having to take any active steps.

(iii) They will help 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 will collectively allow for much more data to be used when determining distributed generation ("DG") impact studies.

4 D.P.U. 15-120, Grid Modernization Plan (filed June 14, 2016) at 29, 32, 35, Atts. 3, 5; Order at 154-155.

5 D.P.U. 15-120, Grid Modernization Plan (filed June 14, 2016) at 29, 32, 35, Atts. 3, 5; Order at 155, n. 81.

The ADMS/DSCADA solution will enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.

(1) Volt Var Optimization (VVO)

VVO is a distribution level program where voltage control devices are intelligently controlled in a coordinated manner to optimize the distribution system. This program is designed to minimize system losses, while simultaneously reducing both demand and energy use of customers.

(a) Description of Work Completed

The Volt Var Optimization (VVO) deployment for Massachusetts was initiated in the first quarter of 2019 with the selection of Substations and Feeders to be upgraded with the new technology. Throughout the year, the Company made continual progress toward the goal of deploying VVO onto 16 feeders. This began with the training of employees and contractors that have a role in the deployment; and will continue through the actual deployment and commissioning of field devices. Successes for the year included:

- Refinement of the selection process to pick the highest priority feeders that will result in expedient deployment and best efficiency performance.
- Streamlining the overall process, from design to commissioning, reducing end-to-end duration of the deployment.
- Documentation for all key processes with updated check sheets, job aids, etc.
- Building a pipeline of equipment (Capacitors, Regulators, Advanced Controls, etc.) to ensure a continuous flow of devices from supplier to meet project demands.
- Completed design for all field work and issued work requests for the entire project
- Completed all device installations for one feeder.
- Gained many insights into the process that allowed the Company to make improvements in design, construction, installation, commissioning and safety.
- Optimization of pole top devices used to obtain voltage monitoring.
- Delivered a central location for VVO device locations and their associated control settings.
- Developed device office commissioning step which led to more efficient field commissioning efforts.
- Regionalized implementation areas and staffed them with proficient project managers whose efforts streamline the deployment process.
- Installed, configured and commissioned the server that runs the VVO software.

- Installed and configured the RTU needed to direct data traffic between the field devices and the VVO server.
- Tested end-to-end data transfer and control functions from the VVO server to the field devices for the feeder that had completed field construction.
- Updated Energy Management System (EMS – Part of DMS system) visual screens with all new VVO field devices.

(b) Lessons learned/challenges and successes.

Lessons Learned

- We determined there were field devices that could be modified to increase the quality of collected data as well as shorten the internal build processes prior to install.
- We recognized the need for a centralized repository for VVO device locations and their associated control settings; as a result, we developed a SharePoint site to collect and share this information.
- During the field commissioning process, we found there were portions of the process we could complete during the internal building phase.
- We developed device office commissioning which led to more efficient field commissioning efforts. We documented this new process as a best practice reference.
- We identified safe working practices for new equipment and trained all work crews.
- We recognized the need to forecast the workload for proper planning of resources (both labor and material) and began a series of meetings with the appropriate teams to keep them aware of the project progress and schedule.

Challenges

- The VVO technology was new to the workforce in Massachusetts. We needed to train the workforce to familiarize them with the operation of VVO and the uniqueness of the equipment used for the program.
- We identified a challenge in our material planning and management processes that limited visibility of material availability and location. This is being addressed for future programs.

Successes

- We were able to build a new streamlined process for Office Commissioning that led to streamlined workflow and reductions in downstream errors.

- We were able to demonstrate that a program like VVO can be completed from end to end within one calendar year (from design to in-service).

(c) Actual verses planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 20-24.

The Company began deploying field devices i.e. Smart Capacitors and Line Voltage Monitors in October 2019. Thus far there has been complete installation of field devices on one feeder out of the Stoughton Substation. In December 2019 the VVO Utilidata AdaptiVolt Server was installed and commissioned at the Northborough Control center.

This deviated from our original plans primarily driven by unavailability of materials required to progress much of the work. An effort to source all the materials was also impacted by longer than expected lead times which shifted the planned projects into the CY 2020 plan year.

(d) Performance on implementation/deployment.

The Company deployed and tested equipment on one feeder out of the Stoughton substation. We will need to complete all feeders and the substation work to activate the VVO system and begin compiling performance data.

(e) Description of benefits realized as the result of implementation.

There are no benefits realized yet for this annual reporting period as the VVO system has not been activated.

(f) Description of capability improvement by capability/status category.

We will begin compiling data related to capability improvements once the VVO system is enabled and operational. Despite not having the VVO system functional yet, there is an ancillary benefit of deploying even a few devices: increased visibility at the Distribution

Control Center ("DCC") level. The team in the DCC can see these deployed devices which leads to more visibility and better response to storm conditions, for example.

After the system is fully operational, the expected benefits of the deployment of VVO include:

- **Improved feeder power factor**
- **Flatter voltage profiles**
- **Reduced feeder losses**
- **Reduced peak demand and reduced energy consumption by customers**
- **Reduction in greenhouse gas (GHG) emissions**
- **Improved management of the distribution system which will assist in the integration of distributed resources**
- **Improve feeder voltage performance**
- **Improved system awareness into the daily operations and planning processes**

(g) Key milestones.

Substation	**E. Methuen**	**Maplewood**	**Stoughton**
Milestone	**Completion Date**		
Complete Project Sanction	May-2019	May-2019	May 2019
Engineering Completed	Jul-2019	Jul-2019	Jul 2019
Design Completed	Dec-2019	Jan-2020	Nov-2019
Construction Completed	May-2020	May-2020	Mar-2020
In service date	Jun-2020	Jun-2020	May-2020

(h) Updated projections for remainder of the three-year term.

The Company is forecasting completion of 16 feeders during the three-year plan period. Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the updated projections. Refer to columns P-R, rows 20-24.

CY2020	Complete installation of VVO on 16 Feeders
CY2020	Initiate Measurement and Verification (M&V) Analysis
CY2021	Determine efficiency/benefits from the VVO technology

The Company is also progressing the design and construction of a modest subset of advanced capacitors that will be deployed in Central and Western Massachusetts to mitigate potential impacts of Distributed Generation. There is a situation where the transmission system is seeing a high voltage concern when they model the high volume of distributed generation proposed for central and western Massachusetts. The voltage increase is due to the offloading of the transmission line, leaving excess VARs, which is driving the voltage up. The solution being pursued is to replace existing capacitor banks on the Distribution system with smart capacitor banks, which will be set to turn off during light load conditions, with a voltage override. The ISO approved this approach through the Company's Transmission Planning organization. The Company has identified 25 capacitor banks to be spread across multiple substations in Central and Western territory. As a result of these emerging Distributed Energy Resource issues and opportunities in Central and Western Massachusetts, the Company is deploying voltage optimization investments to progress grid modernization objectives.

Div.	Operating District	Sub Ref	Substation	City	Feeders	Devices
BSW	Central – 01	607	Crystal Lake	Gardner	4	6
BSW	Central – 01	609	E Westminster	Westminster	2	4
BSW	Central – 01	525	Lashaway	West Brookfield	1	1
BSW	Central – 01	415	W Charlton	Charlton	1	1
BSW	Central – 01	55	Treasure Valley	Rutland	1	1
BSW	Central – 01	612	E Winchendon	Winchendon	1	1
BSW	Western - 09	702	Chestnut Hill	Athol	2	4
BSW	Western - 09	507	Wilbraham	Wilbraham	1	1
BSW	Western - 09	508	E Longmeadow	E Longmeadow	1	1
BSW	Western - 09	503	Palmer	Palmer	2	2

BSW	Western - 09	139	N Hampden	Hampden	1	1
BSW	Western - 09	516	Little Rest Rd	Warren	1	1
BSW	Western - 09	523	Thorndike	Ware	1	1

(2) Advanced Distribution Automation (ADA).

ADA is a Fault Location, Isolation and Service Restoration ("FLISR")-based advanced distribution automation program where sectionalizing protection equipment is automated and controlled in a coordinated manner, to minimize the effects of outages. FLISR reduces the impact of interruptions on the distribution system through the installation of automated switches along the main line and tie points of a feeder. This allows a fault to be automatically isolated into a sub-section of the feeder and the uninvolved sub-sections to be resupplied via automated tie points, significantly reducing both impacted customers and outage durations. National Grid currently has communications capabilities to some of the reclosers on the distribution system but does not currently coordinate their operation during faults beyond their local protective control. The Company also has limited FLISR capabilities still active within the Worcester Smart Energy Solutions Pilot area. The ADA scheme will replace manual tie points between adjacent feeders, to provide for downstream restoration. It also will integrate enhanced telecommunications and additional control on existing protective switches, and potentially add switch locations as necessary to optimize system reliability.

(a) Description of work completed.

The FLISR/ADA program deployment for Massachusetts was initiated in the second quarter of 2019 with the selection of Substations and Feeders to be upgraded with the new technology. Throughout the year, the Company made continual progress toward the goal of deploying FLISR/ADA onto 16 feeders. The FLISR/ADA program has achieved several milestones on the journey to a more modern grid as it moves toward the definitive goal of an automated and reliable infrastructure. The first round of deployment for the FLISR program focused on minimizing complexities while delivering customer benefits. With that intention in mind, the candidates selected for the FLISR schemes avoided feeders with moderate to high amounts of Distributed Energy Resources (DERs) or pre-existing field devices. Other factors considered when determining areas of implementation included but were not limited to: feeder metric data: poor, problem, and worst performing feeders; transformer metric data; feeder length; and number of customers served.

The following is a list of work completed for the year:

- Documentation of all key processes with updated check sheets and job aids.
- Engineering analysis of candidate circuits through evaluation of poor performing feeders and various metrics.
- Streamlining the overall process, from planning and designing to commissioning and implementation to reduce end-to-end duration of deployment.
- Documentation of all key processes with updated check sheets and job aids.
- Verification of good signal for field device communications with telecom surveys.
- Proactive procurement orders with Inventory Management (Reclosers, Control Boxes, Radios, Feeder Monitors, etc.) to get ahead of long lead times and meet project schedules.
- Completed design for all field work and issued work requests for the 16 feeders.
- Successfully identified the need for alternative settings and updated control box settings request forms to include features required for automation.
- Collected lessons learned throughout the process to make improvements in planning, engineering, design and procurement

(b) Lessons learned/challenges and successes.

Although the Company has not initiated deployment, it leveraged the lessons learned from its Worcester Smart Energy Solutions Pilot ("Pilot") which deployed ADA as well as new

learnings since initiating the effort. The key lessons from the grid-facing portions of the Pilot include:

- **The importance of ensuring the communications network required to support grid devices is installed, tested and enabled to provide an efficient deployment and commissioning of distribution automation.**

- **The need for a broader set of employee roles and capabilities than exists in the current utility workforce in order to deliver and manage this new, enhanced equipment and technologies.**

- **Using a hybrid grid communications strategy where a combination of WiMax, cellular, 900Mhz and other solutions can coexist to provide options for connecting to devices when circumstances require it.**

- **The need to establish an independent data analytics solution and information repository for the engineering data required to support the evaluation plan and perform advanced engineering analysis.**

- The significance of communication among stakeholders regarding candidate selection to avoid problematic areas of implementation. Suggestions and open discussion help bring to light the roadblocks that are not otherwise known.
- The need to ensure that zone logic and automation capabilities are programmable within Orion so that scheme can successfully be commissioned once the installation is complete to mitigate problems on the back end.
- The need to verify stable communications of field devices and take proactive measures for telecom signal verification once recloser locations were scoped.
- Prioritization of inventory management by placing proactive material/equipment orders to align the long lead times into the project plans and to avoid delays once installations are ready to mobilize.
- Anticipating unknowns and adapting the plans and response to minimize impacts to plans and schedules. This occurred in the form of the need for alternative settings for reclosers that act as the tie points; this need was identified and implemented ensuring that it will be accounted for in future rollouts.

(b) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 16-19.

The Company planned 20 recloser installations in 2019 but has not actively deployed ADA on circuits during the year. During 2019, efforts to better define and streamline our processes for the design, configuration, testing and construction of field devices was prioritized which altered some initial assumptions for the construction and installation processes. The Company also encountered materials lead time and vendor procurement delays which impacted the ability to schedule work. There is also internal prioritization of materials management and incorporation of materials demand increases described in the lessons learned. The Company progressed procurement of Orion LX servers for the program which will serve as the FLISR Automation Platform until ADMS is implemented.

(c) Performance on implementation/deployment.

The Company has not actively installed or deployed ADA on circuits during 2019. However, key accomplishments from the Company plans were as follows:

- The Company designed eight ADA Schemes on sixteen feeders.
- The Company procured server equipment for the Northborough Control Center which allowed us to test the ADA schemes and verify the proposed logic was functional.
- The Company updated and standardized the new 6IVS reclosers from the vendor.
- The Company verified stable signal strength for field device locations through telecom field surveys.
- The Company completed all designs required for the program to prepare for recloser settings installation.
- The Company implemented and tested alternative settings for tie point reclosers and incorporated the necessary updates to documentation.

(d) Description of benefits realized as the result of implementation.

There are no benefits realized yet for this annual reporting period. The benefits of ADA are expected to include:

- **Optimizing system performance – National Grid anticipates approximately a 25% reduction in main line customer minutes of interruption (“CMI”) on the individual feeders targeted for the ADA deployment. This projected reduction is based on**

historical analysis of actual past performance in the SES Pilot, as well as calculated anticipated reductions from historic outages.

- **Optimizing system demand – The additional operational data collected by the automated switches will support the improved management of the distribution system, assisting in demand optimization.**

- **Interconnecting and integrating distributed energy resources – The additional operational data collected by the automated switches will support the improved management of the distribution system, assisting in the interconnection of DG and potential integration of distributed resources as a tool to operate the system.**

(e) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

ADA capability improvement will enhance reliability and resiliency. These metrics will be tracked once ADA is fully commissioned and live.

(f) Key milestones.

	Area of Scheme & Target Dates		
Milestones	**BSN - 4 ADA Schemes**	**BSS - 3 ADA Schemes**	**BSW - 1 ADA Scheme**
Project Sanction Completed	May 2019	May 2019	May 2019
Engineering Completed	July 2019	July 2019	July 2019
Design Completed	Nov 2019	Nov 2019	Nov 2019
Construction Completed	June 2020	June 2020	June 2020
Commission Completed	July 2020	July 2020	July 2020
In service date	July 2020	July 2020	July 2020

(g) Updated projections for the remainder of the three-year term.

The Company is forecasting deployment of 70 reclosers on 16 feeders during the three-year plan period. Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 16-19.

(3) Feeder Monitors.

The feeder monitors program will install interval power monitoring devices on feeders where the Company does not currently have this information. Feeder monitors will create visibility for the control centers and the information collected will be used to inform the engineering planning and asset management assessments.

National Grid has over 1,100 distribution feeder circuits in Massachusetts. Of these circuits, less than half are monitored by an interval sensor and therefore do not report live data to the operational control centers or inform electric planning with interval data. This lack of historic and live interval data represents a gap in National Grid's situational awareness. While the electric system of the past has been operated and maintained without this data, having this data available in the future is important to enabling the modern electric grid, which has increased reliability requirements and proliferation of DERs. Installing feeder monitors will fill this awareness gap and assist in more efficient operation and maintenance, planning and storm recovery, in furtherance of the Department's objectives for grid modernization.

(a) Description of work completed.

The Company has reviewed the population of feeders, with a focus on overhead feeders, in National Grid's distribution system which lack sensing capabilities. As large upgrades are made to substations and circuits, often this need is addressed with sensing and communicating equipment. National Grid will deploy head-end mainline feeder monitors which would be used to capture real-time voltage, current and power. The operations control center will use this information, as will electric system planners, to help optimize the control and design of the electric system. The Company has undertaken a planning assessment to prioritize the deployment of feeder monitors through the three-year grid modernization plan term.

Over the year of 2019, the preliminary and initial stages were all completed. These stages include: initial location chosen, preliminary engineering completed, sanctioning, design

start, telecom cell strength verified, materials procured, construction started, and commissioning started. Following is a list of work completed this year:

- Preliminary Engineering was completed in order to access and choose the highest areas of impact for feeder monitoring to be installed. These areas were typically categorized as feeders with large customer counts but low historical data.
- Sanctioning was completed for the project and the scope of the project was clearly laid out.
- Design surveyed and checked the locations given to them by preliminary engineering. They take these locations and design each project in accordance with National Grid standards.
- Both Telecom Operations (Telecom Ops) and Distribution Control and Integration (DC&I) completed cellular strength testing for all locations to determine if more advanced designing was needed or location had to be changed.
- Materials were procured and pipelines were established to ensure that consistent delivery times were communicated and maintained.
- Telecom Ops in conjunction with Grid Mod and Engineering created an office commissioning step to ensure that all communication equipment was operational before field deployment.
- Field construction and commissioning of five field devices was completed.

(b) Lessons learned/challenges and successes.

After going through the first five installs there were several lessons learned, including:

1. Assembly of the mounting brackets for the control box should be attached to the box in house.
2. The commissioning process needed to be updated and shared with the control room in order to allow for a smooth commissioning process between the Control Center and the Overhead group.
3. Sensor cables should be phase labeled and the phase diagram of feeder should be given ahead of time to Overhead in order to increase the efficiency of device installation.
4. We began training Overhead to attach sensors to cross arms on the ground and then use two trucks to lift them if the cross arm was being replaced as a work method for increasing efficiency.
5. In order to simplify the process for grounding and tampering of the control box in the field, hardware installation steps were added to the office commissioning phase. With this being addressed in office, it helps reduce the additional work required for field installation.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 12-15.

This year five feeder monitors were completed. The main contributing factor to the 20 sensors deviation was a materials manufacturing issue on the vendor's side that caused a stop ship in the Lindsey sensor. There were no alternative parts available within our standard equipment list that covered similar capabilities. This resulted in a small amount of materials being transferred from the Company's affiliate in Rhode Island to the Company so that five installs could be completed in order to familiarize crews with the install steps and provide onsite training to crews to boost the efficiency of later installations. As of December 2019, the materials issue has been resolved and 125 sensors are on hand currently to pull from for installs with another expected to be delivered in the first quarter of 2020. The 20 additional feeder monitors are planned to be delivered in the first quarter of 2020.

(d) Performance on implementation/deployment.

The deployment of the five sensors was successful. All sensors are reporting data back correctly and completing their designated function. With the completion of preliminary engineering cellular surveys, there have been no issues with the data collection functionality of the feeder monitors. All data is tracked and can be accessed using our PI Historian software. See Benefits in the following sub-section(e).

(e) Description of benefits realized as the result of implementation.

- Visibility of real-time demand.
- During the winter storm event on October 17th, 2019, the feeder monitors saved time in the technical assessment of the 910W2 feeder in Hanover, Massachusetts. During the emergency outage our planning engineers responded to customer calls reporting outages centered around the Water Street 910 Substation Area. Before dispatching damage assessors, planning engineers utilized PI Historian software to verify that there was no major impact to the feeder from the substation level.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

With the five completed installs we have already begun to see an increase in the visibility that the DCC and Distribution Planning and management teams have on the loading of lines. This allows for there to be better response times during storm conditions.

(g) Key milestones.

Milestones	Install Numbers and target dates					
FM installs	1-9	10-25	25-55	55-90	90-125	125-150
Complete Project Sanction	Apr-19	Apr-19	Jul-19	Jul-19	Jul-19	Jul-19
Engineering Completed	Jul-19	Oct-19	Jan-20	Feb-20	Mar-20	Apr-20
Design Completed	Jul-19	Oct-19	Jan-20	Mar-20	Mar-20	Apr-20
Construction Completed	Feb-20	Mar-20	May-20	Jun-20	Jul-20	Aug-20
In-service date	Feb-20	Mar-20	May-20	Jun-20	Jul-20	Aug-20

(h) Updated projections for remainder of the three-year term.

The Company is still targeting completion of 153 feeder monitors during the three-year plan period. Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template

provides the updated projections for the 2020 plan year. Refer to columns M-U, rows 9-14.

Plan Year 2019

District	Town	Device	Qty
Western	Palmer	Lindsey	2
	Ware	Lindsey	1
Total			3

District	Town	Device	Qty
Merrimack Valley	Andover	Lindsey	2
Total			2

District	Town	Device	Qty
North Shore	Beverly	Lindsey	2
Total			2

District	Town	Device	Qty
Southeast	Attleboro	Lindsey	1
	Dighton	Lindsey	1
	Milford	Lindsey	1
	Swansea	Lindsey	2
Total			5

District	Town	Device	Qty
South Shore	Abington*	Lindsey	2
	BridgeWater*	Lindsey	2
	Brockton	Lindsey	2
	Hanover*	Lindsey	1
	Pembroke*	Lindsey	1
	Quincy	Lindsey	2
	Rockland	Lindsey	1
	Scituate	Lindsey	2
Total			13

* Completed = 5

Plan Year 2020

District	Town	Device	Qty
Merrimack Valley	ANDOVER	Lindsey	1
	CHELMSFORD	Lindsey	1
	HAVERHILL	Lindsey	2
	LAWRENCE	Lindsey	5
	NEWBURY	Lindsey	1
Total			10

District	Town	Device	Qty
North Shore	BEVERLY	Lindsey	5
	GLOUCESTER	Lindsey	2
	LYNN	Lindsey	1
	MEDFORD	Lindsey	10
	NAHANT	Lindsey	2
	REVERE	Lindsey	4
Total			24

District	Town	Device	Qty
South Shore	ABINGTON	Lindsey	3
	Bridgewater	Lindsey	4
	BROCKTON	Lindsey	18
	EASTON	Lindsey	4
	GROVELAND	Lindsey	1
	Hanover	Lindsey	2
	HOLBROOK	Lindsey	2
	Pembroke	Lindsey	1
	QUINCY	Lindsey	18
	ROCKLAND	Lindsey	1
	SCITUATE	Lindsey	3
	WHITMAN	Lindsey	1
Total			58

District	Town	Device	Qty
Southeast	ATTLEBORO	Lindsey	3
	DIGHTON	Lindsey	1
	MENDON	Lindsey	1
	REHOBOTH	Lindsey	3
	SWANSEA	Lindsey	3
Total			11

District	Town	Device	Qty
Western	ATHOL	Lindsey	3
	BUCKLAND	Lindsey	1
	NORTHAMPTON	Lindsey	1
	PALMER	Lindsey	2
	ROYALSTON	Lindsey	1
	SHUTESBURY	Lindsey	1
	Ware	Lindsey	1
	WARREN	Lindsey	3
	WENDELL	Lindsey	3
	WMeco	Lindsey	1
Total			17

District	Town	Device	Qty
Central	BARRE	Lindsey	2
	NORTH BROOKFIELD	Lindsey	1
	SPENCER	Lindsey	3
	WINCHENDON	Lindsey	2
Total			8

(4) Communications and Information/Operational \Technologies.

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 factors.**
- **Provide to the operations groups the capability to manage, maintain and troubleshoot the communications network.**
- **Enable new grid technologies as they become available and future-proof the network as much as possible.**

The telecommunications network will be comprised of two main layers. The Field Area Network ("FAN") will provide "last mile" communications to the end devices. Field-installed grid controls are the endpoints on this network layer. The Wide Area Network ("WAN") provides the backbone and ties the end devices to major field communications nodes and ultimately the ADMS and back-end data systems. Substations and other Company facilities make up the major nodes of the WAN.

(a) Description of work completed.

In anticipation of grid modernization, the Company undertook a strategic assessment of operational telecommunications during 2017. This initial assessment identified technologies and opportunities for progressing grid modernization investments. In 2018, the Company leveraged that strategic assessment to identify specific elements that were critical investments for progressing grid modernization. During 2019, the Company commissioned coverage and channel reuse studies for both the 700 MHz and 900 MHz spectrums and evaluated other available spectrums and technologies. Results provided initial baseline costs for the acquisition of 700 MHZ and 900 MHz spectrum and the ability to model implementation costs for base stations across the service territory. The Company has also established a working group with joint utilities to share lessons learned and collaborate on the various types of networks that have been implemented. The Company has also reviewed equipment vendors as well as companies that own spectrum or lease spectrum, and vendors that offer shared solutions to better understand the marketplace and associated costs.

The Company issued a Request for Proposal ("RFP") for a software tool to enable the planning, designing, engineering, deploying, commissioning, and maintaining of telecom networks. Vendor demonstrations on the execution of test scripts were completed and final evaluations and vendor selection will be completed in 2020.

The Company performed a current state assessment of the WAN and determined that the existing DMX SONET technology has reached end-of-life and will not handle the future growth to support the needs for Grid Modernization. The DMX SONET system provides a redundant communication network linking critical transmission substations and corporate facilities utilizing private (Company-owned) fiber, additional fiber leased from third parties, and microwave links. The Company engaged with a third party to deliver a market research report to identify vendors with available technologies, product maturity, US-based implementations, and utility experience. Based upon these efforts, the Company has begun drafting an RFP for the replacement of the DMX SONET backbone equipment. The DMX SONET replacement equipment will be the technology that will be implemented to expand the WAN and future-proof the backhaul for multiple technologies in support of grid modernization.

The Company recognizes that with new technologies, construction standards will need to be developed for the expansion of the fiber network. In support of this effort, significant progress has been made in developing a standard for entry of fiber circuits into substations. Field surveys were performed on recently installed Optical Ground Wire (OPGW) fiber to document splice locations and the work remaining to complete fiber circuit termination to substations for WAN expansion.

(b) Lessons learned/challenges and successes.

The Company had not planned for active installation or deployed communications or OT/IT on circuits during 2019. However, there have been some lessons learned.

Through the commission of studies and spectrum evaluation, the Company has learned that spectrum acquisition is population-driven creating large cost differentials for metropolitan areas versus rural. This increases the difficulty in obtaining ubiquitous service territory

coverage for the FAN using a single spectrum creating the potential need for hybrid solutions.

Successes to date include:

- The knowledge gained through the market research report and the initial evaluation of available DMX SONET replacement technologies has allowed the Company to make a more informed selection of future-proof WAN designs.
- The Company has begun developing cost models for available spectrum and technologies to evaluate the cost-effectiveness of FAN investments in support of the GMP.
- The field surveys have identified locations for future work to be completed for WAN expansion which will be supported through the standards and processes that are in progress.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 28-29.

The Company had limited spending for the 2019 annual report period. The number of nodes completed is associated with the devices installed and commissioned. The Company had not planned for implementation and deployment of wide area network investments during 2019 and continued to research and evaluate technologies and solutions for the expansion of the WAN and FAN to address future long-term growth.

(d) Performance on implementation/deployment.

The Company installed cellular communications for the devices installed and commissioned. The Company had not planned for implementation and deployment of the WAN and FAN in 2019.

(e) Description of benefits realized as the result of implementation.

The Company had not planned for implementation in 2019. Communications and OT/IT are enabling technologies that will enable the benefits to be realized through the other technologies to be installed as part of Grid Modernization.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

The path to deliver the greatest customer benefits through WAN and FAN investments will occur over the long-term. However, in the near-term the Company recognizes that the use

of public cellular can provide some customer benefits until final WAN/FAN solutions are delivered.

(g) Key milestones.

Milestone	Target Date
FAN 700 and 900 MHz coverage and channel reuse studies	Completed in October 2019
WAN Market Research Report	Completed in December 2019
WAN equipment vendor RFP	March 2020
Construction standards for WAN expansion	June 2020
WAN equipment vendor testing	August 2020
WAN vendor selection	September 2020
Substation fiber termination using developed WAN construction standards	December 2020
Field surveys for WAN expansion	December 2020
FAN business case	December 2020

(h) Updated projections for remainder of the three-year term.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the updated projections for the 2020 plan year. Refer to columns M-U, rows 28-29.

The Company is targeting completion of the following:

- **Selection, procurement, and initial deployment of the TOMS platform, a software tool to enable the planning, designing, engineering, deploying, commissioning, and maintaining of telecom networks.**

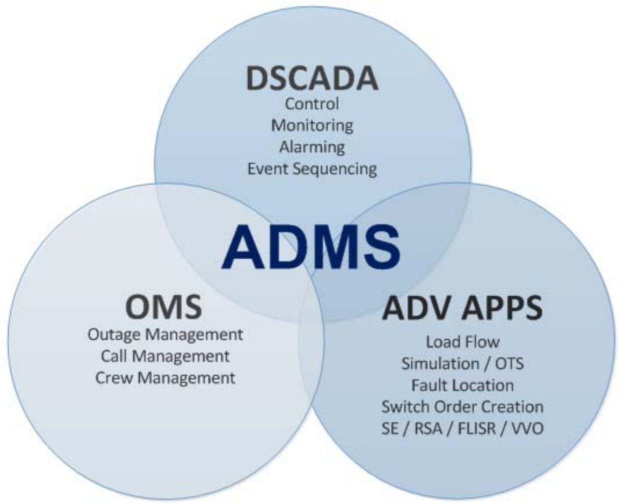
- Ongoing node activation for field devices installed and commissioned

- Selection of the WAN equipment vendor for the DMX SONET replacement
- Development of approved standards for the entry of fiber to substations and construction procedures for installation, testing and commissioning
- Completion of field surveys of fiber availability for WAN expansion

(5) ADMS/DSCADA.

Currently, National Grid utilizes an Energy Management System ("EMS"), a Supervisory Control and Data Acquisition ("SCADA") system, and an Outage Management System ("OMS"). EMS/SCADA is used to monitor remote devices real time and store in a centralized location to be utilized to monitor and control the electrical grid. The OMS centralizes customer outage calls and trouble notifications to be displayed and compiled on a connected network model representation of the electric grid to allow for proper analyzing and dispatching of the calls and outages.

Modern grid complexities such as EVs and other nonconforming loads, distributed energy resources, and an increasing amount of remote grid device data are creating a challenging operational landscape. An ADMS is a group of control room-based hardware and software used by electric distribution operators to visualize, monitor, and control the electric grid with advanced functionality. The solutions and applications in the system support continued safe and reliable electric grid operations with the added complexities of the modern grid. The ADMS system includes three main modules, a DSCADA, an OMS, and advanced application functionality (DMS). These modules operate on a common operational platform. The system allows for greater visibility, situational awareness, and efficiencies in operations processes. The advanced applications included in the system can help the control room operator make more optimal system configuration decisions with respect to power aspects of the grid by simulating future states and configurations for the distribution grid. Applications can also centralize and automate distribution grid functions such as VVO, fault location, and distribution automation. The ADMS solutions incorporate real time data via the DSCADA module from an ever-growing number of remote grid devices and distributed energy resources ("DER"). The ADMS is an intelligent network platform supporting the operational integration of DER's and is a foundational investment for transition to Distributed System Operator ("DSO").



This project will implement a phased approach for rolling out the ADMS, which includes implementing distribution management system applications followed by a refresh of the existing OMS as a module of the ADMS. The project will implement a distribution specific DSCADA system dedicated to the management and control of the distribution networks. The resulting DSCADA system will be integrated with the distribution management system applications and OMS creating a common operations ADMS platform. The overall project is expected to take up to five years before fully implemented.

Dependency on data:

Modern grid operations require increasing granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality. While the system and data maintained by the Company has been fit for purpose to date, the introduction of new use cases, such as for ADMS applications and hosting capacity analysis, requires change. Industry experience in the deployment of ADMS and similar systems has shown that significant investment in information enhancement is needed to enable the efficient use of these advanced applications. For ADMS to work properly there is an overall dependency on not only the data and data quality but also the frequency of the data updates, as DMS is used for real-time operations and will require an up-to-date, as-built network model.

GIS improvements and data hardening are underway. This includes a general scrubbing of the data as well as changes to baseline GIS to allow for new asset types, new equipment, expanded attributes and characteristics. It would allow for the proper programming to facilitate the capture of greater data and modeling granularity in places such as secondary networks to support the extraction of behind-the-meter DER. The modeling of substations would also be pursued in the ADMS roadmap.

Dependency on building out DSCADA substation control capabilities:

This investment will facilitate the virtual (dual porting) and physical separation of Remote Terminal Units ("RTU") and necessary network changes to allow for distribution components (substation and feeder level) to communicate with a dedicated DSCADA system. With the proposed separation of the SCADA system into a transmission SCADA and distribution SCADA system it will be required that any RTU presently sharing transmission and distribution equipment data points be reconfigured either virtually or physically to communicate with the separate SCADA systems. This work will allow the separation of the current single transmission and distribution SCADA system into separate transmission SCADA and DSCADA systems allowing for expansion of remote monitoring and control while supporting continued stability for transmission SCADA taking into consideration lessons learned from past control center-centric projects.

Multi-phased initiative rollout:

The ADMS project will be implemented using a phased approach that will put different modules and functionality into service over the period of CY2021 through CY 2024.

A phased approach for the ADMS has many benefits. It will allow the end users and support staff to become familiar with the system functionality and facilitate proper adoption of new ways of working before advanced functionality is enabled. By leveraging process analysis to target change management and training activities, the Company is ensuring proper adoption and benefits realization from the systems and applications. It will allow for Company processes and procedures to be refined for both operational and data support aspects of the system to ensure resiliency and sustainability as reliance on the ADMS system increases. It also allows for interdependent projects to mature as required to support full implementation.

The first phase of the ADMS project will put distribution management system applications in service for the electric distribution control rooms to use in a monitor and inform capacity. The target in-service date for this functionality is the second quarter of CY 2021.

The second phase of the ADMS project will refresh the existing OMS as a module of the ADMS and build out DSCADA functionality, enabling management and control of the electric distribution grid from a common operations platform. The target in-service date for this functionality is late CY 2023 through early CY 2024. When complete this common centralized platform ADMS will allow for the continued integration of new technologies,

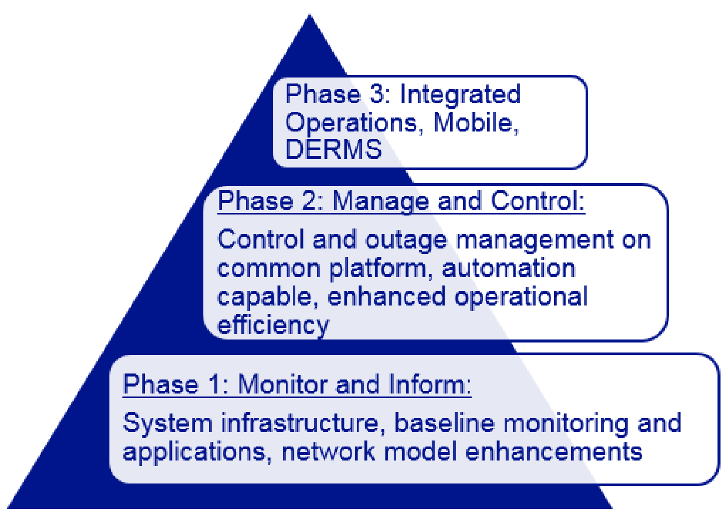
expansion of solutions, and operational integration of distributed energy resources. The phased rollout will include the following steps:

<u>Phase 1</u>

I. Requirements and capability specification, enterprise architecture review
II. Data element identification and GIS data improvements, extract improvements
III. ADMS network and infrastructure specification, procure, and build
IV. System build and data population, validate application functionality
V. Acceptance testing of baseline monitor and inform applications
VI. Production implementation of monitor and inform functionality via baseline DMS applications on a predetermined number of feeders

<u>Phase 2</u>

I. Design, test and enable the outage management (OMS) components/modules of the ADMS and retire the existing National Grid OMS
II. Implementation of a DSCADA leveraging data from substations via RTU work
III. Enable DSCADA integrated with OMS and applications to provide common platform visualization and management for the distribution network
IV. Expansion of applications including advanced functionality capable of automation and control
V. Move towards active network management interfacing with remote metered and grid edge devices, potential future AMI infrastructure, DERMs, and future mobility solutions



a. Description of work completed.

The Company has completed an analysis and scoping effort for the development of the ADMS and DSCADA effort. Requirements are completed, and system design is in process. Data cleanup, expansion and addition needs are understood, and dependencies are mapped. A thorough analysis of operational procedures effected by the rollout of an ADMS is being conducted along with a review of change impacts and training requirements. This will

ensure the solution fits as designed into operations, is properly adopted, and delivers expected benefits.

The Company also has performed the following work in 2019:

- **Organization built and resourced for project implementation**
- **Project plan built and linked to supporting and dependent projects and initiatives (GIS and RTU)**
- **Change management and business process groups built and resourced**
- **Project reporting, controls and governance established**
- **Full requirements definition for ADMS (OMS, DSCADA and DMS) for phase 1 and phase 2**
- **Gap analysis for both functional and non-functional requirements completed**
- **Demonstration feeder proof of concept with vendor using National Grid network model**
- **Enterprise architecture review and approval for proposed ADMS**
- **Preliminary interface definition and requirements definition**
- **Preliminary system architecture and hardware design completed**
- **Mapping of all data and data requirements for selected applications**
- **Perform high-level connectivity and device attribute validation, GIS data extract testing and development, feeder tuning, and preliminary result comparison with CYME baseline model**

b. Lessons learned/challenges and successes.

- Significant additions and expansion to base network model data to support ADMS advanced applications is required beyond what is presently used for distribution operations. The definition of interdependent programs and systems such as GIS have been noted, dependencies have been linked and are tracked based on developed data criteria.

- ADMS applications will be tested and rolled out on a predetermined number of feeders that benefit most from the solutions and cover a wide sample of our operating areas. This will help to ensure consistent solutions, both during system test and production system use, again enhancing benefits and adoption.

- Change management, training development, and process design were properly staffed and considered a critical part of the project. Proper resourcing and skill sets were identified to ensure successful business integration and adoption of ADMS by leveraging process analysis to target change management and training activities ensuring proper adoption and benefits realization from the systems and applications.

- Implementation and system testing teams were reorganized based on lessons learned from past implementations. IT standards were put in place to deliver across programs consistently and included resources, processes, standards, and tools.

c. Actual vs. planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 25-27. The Company progressed on procurement of the new ADMS/DSCADA software in 2019. Planned spending was below initial estimates. National Grid performed an organizational realignment to ensure related transformational programs (ADMS being one of them) can be managed effectively to maximize operational benefits and reduce overlap. These changes along with resourcing challenges due to a tight job market and niche skillsets required created a slower than expected ramp up for the project. New roles were identified during the design phase of the project taking into consideration lessons learned from past projects. Resourcing of proper skill sets to complete business process analysis, change assessment, governance, and controls was completed to ensure successful business integration, adoption, and benefits realization from the systems and applications. System architecture was reviewed to ensure alignment with other Company initiatives and design was reviewed to ensure compliance with internal standards. Additional resources to support system testing, and quality assurance was completed.

d. Performance on implementation/deployment.

The Company has not actively installed or deployed ADMS/DSCADA investments during 2019. Therefore, there is no performance on implementation and deployment for this annual reporting period. The Company had not planned to install ADMS/DSCADA in 2019.

Project governance, reporting and key performance indicators were developed to ensure the project continues to develop on track to yield proposed benefits

e. Description of benefits realized as the result of implementation

The Company has not actively deployed ADMS during 2019. The Company had not planned to install ADMS/DSCADA in 2019. Therefore, there are no benefits realized for this annual reporting period.

f. Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

The capability improvements expected to accrue during the ADMS/DSCADA solution include:

- **Expanded situational awareness and visibility of future predicted states with respect to system operations.**
- **ADMS will create a platform to enable utilization of exponential growth of remote monitoring, control and distribution automation.**
- **Enable system operations to maintain or improve reliability under the growing system complexities associated with the integration of DERs.**
- **Centralizes visualization, monitoring, control, and automation capabilities maximizing operational process efficiencies.**
- **Enables operators to simulate future state of the grid in abnormal configurations to optimize grid asset utilization.**
- **Enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.**
- **Refresh end of life hardware and software for present production OMS procured in 2009 into common system ADMS.**

g. Key Milestones

Milestone	Target Date
Complete R&D Project Sanction	April 22, 2019
Complete Requirements and Design	March 2020
Complete D&I Project Sanction	March 2020

Complete Development and Implementation	January 2021
Complete User Acceptance Testing	June 2021
Move to Production / Go Live Phase 1	June 2021

h. Updated projections for remainder of the three-year term.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns M-U, rows 25-27.

While developing the plans in 2018 and 2019, the Company realized the early goal of implementing Phase 1 of the ADMS solution by December 2020 was not practical. As a result, the final plans and updated projections have second quarter of CY2021 as a realistic implementation date. The Company is targeting roll out of the initial phase of capabilities of ADMS for June 2021.

i. Actual vs. planned implementation and spending, with explanations for deviation and rationale.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns M-U, rows 25-27.

While developing the plans in 2018 and 2019, the Company realized the early goal of implementing Phase 1 of the ADMS solution by December 2020 was not practical. As a result, the final plans and updated projections have second quarter of CY2021 as a realistic implementation date. The Company is targeting roll out of the initial phase of capabilities of ADMS for June 2021.

B. Feeder Level Narrative by Investment Category

1. For each investment category:

a. Highlights of feeder level implementation

b. Feeder level lessons learned/challenges and successes

During calendar years 2018 through 2019, the Company has undertaken a distribution planning effort to identify the feeders and locations to pursue investments in grid modernization, looking to balance the overall objectives and the benefits. In future year reports, a feeder level narrative on progress in implementation along with lessons learned, challenges and successes will be available. National Grid does not have additional feeder-

level detail, by investment category, that was not already provided in the prior investment category narratives.

Independent of the GMP, the Company has had experience in installing and operating the core distribution devices that also are part of the GMP. Specifically, the Worcester SES Pilot[6] in Massachusetts and the VVO Program conducted by the Company's affiliate in Rhode Island,[7] Narragansett Electric Company d/b/a National Grid, have informed the Company's GMP efforts in Massachusetts.

[6] See Docket D.P.U. 10-82, National Grid Smart Energy Solutions Pilot Final Grid Evaluation Report (June 28, 2017).

[7] R.I. P.U.C. Docket 4592 - FY 2017 Electric Infrastructure, Safety, and Reliability Plan Volt Var Optimization Pilot.

IV. Description and Report on Each Infrastructure Metric

A. Grid-Connected Distributed Generation Facilities

One of the primary objectives of grid modernization is to facilitate the interconnection of distributed energy resources ("DER") and to integrate these resources into National Grid's planning and operations processes. This infrastructure metric quantifies the DER units connected to the Company's system on a circuit level and substation level. It is important to note that DER developers' decisions regarding DER interconnection may be influenced by tax incentives, subsidies, and costs and availability of the technology, which, in turn, will influence these metrics.

The table below is a summary of the number of DERs connected to the Company's distribution system as of December 31, 2019. Tab 3. Feeder Status in the attached DPU Annual Report Template provides the feeder level details. Refer to columns S-CS.

Fuel Type	Total Units	Nameplate AC Rating(kW)	Capacity Factor	Est Annual Output
Bio Gas	6	2,730	73.3%	17,529,548
Diesel	5	1,675	40.0%	5,869,200
Fuel Oil	2	5,350	40.0%	18,746,400
Hydro	10	5,087	37.4%	16,666,233
Landfill Gas	6	10,875	73.3%	69,829,245
Methane	1	280	57.6%	1,412,813
Natural Gas	157	97,457	57.6%	491,743,119
Propane	2	10	57.6%	50,458
Solar	53,305	1,097,711	13.4%	1,288,536,493
Solar w/ Battery	305	27,484	13.4%	32,261,959
Wind	56	20,311	37.4%	66,542,892
Energy Storage	10	534	-	-
Grand Total	53,865	1,269,503		2,009,188,360

B. System Automation Saturation

This infrastructure metric for system automation saturation measures customers served by fully automated or partially automated device(s). The terms "fully automated" and "partially automated" refer to feeders for which National Grid has attained optimal or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation.

National Grid has initially calculated the system automation saturation to be 505. There have been minimal installations in the 2019 Plan Year, of Grid Modernization investments. The Company is actively validating circuit level details and is providing feeder-specific levels on Tab 3. Feeder Status in the attached DPU Annual Report Template.

C. Number/ Percentage of Circuits with Installed Sensors

This metric measures the total number of electric distribution circuits with installed sensors which will provide information useful for proactive planning and intervention. The installation of sensors provides the means to enable proactive planning and to measure a number of grid modernization initiatives such as VVO and asset management. A sensor analytics development program is an essential part of grid modernization and provides the visibility into network operations needed to move toward an effective grid modernization program.

National Grid has initially calculated the percentage of circuits with installed sensors at 66%. There have been minimal installations in the 2019 Plan Year, of Grid Modernization investments. The Company is actively validating circuit level details and is providing feeder-specific levels on Tab 3. Feeder Status in the attached DPU Annual Report Template.

D. Number of Devices or Other Technologies Deployed

These metric measures how National Grid is progressing with its GMP from an equipment and/or device standpoint. The number of devices installed is compared to the total number of devices planned by circuit for each investment.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L.

E. Associated Cost for Deployment

This metric measures the associated costs for the number of devices or technologies installed and is designed to measure how National Grid is progressing under its GMP. The cost of devices installed is compared to the total cost of devices planned by circuit for each investment.

Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the cost of devices installed compared to the planned costs. Refer to columns D-L.

F. Reasons for Deviation Between Actual and Planned Deployment for the Plan Year

This metric is designed to measure how National Grid is progressing under its GMP on a year-by-year basis. The quantity and cost of devices or technology installed in a given GMP investment year is compared on a year-by-year basis and any variations are quantified and addressed. Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the deviation between actual and planned deployment for the 2019 plan year. Refer to columns D-L, rows 20-24.

The Company detailed the causes for deviation from the planned deployment in each of the investment area sections. In summary, the major contributing factors include: a longer than expected mobilization time period, the detailed planning, engineering and design work performed in 2019 revised original assumptions, and material sourcing and vendor supply delays.

G. Projected Deployment for The Remainder of the Three-Year (2018-2020) Term

This metric is designed to show National Grid's projected deployment for the three-year term under its GMP on a year-by-year basis. The year-by-year investment plan is subject to change based upon the quantity of work completed, the availability of the technology, material lead times, contractor availability, etc. The revised investment plan each year will be used as the basis for projecting the following year's GMP work. Tab 5.b. Spending – 2019 Report in the attached DPU Annual Report Template provides the projected deployment for the remainder of the three-year term. Refer to columns V-AD.[8]

---

[8] The Company notes that its 2020 GMP work could be affected by the recent novel coronavirus, COVID-19, pandemic response. The Company has established plans to safely progress work during the pandemic and provided the Department the Company's Business Continuity Plans for this event. See National Grid Business Continuity Plans – COVID-19, Responses to the Hearing Officer Memorandum Dated March 11, 2020. The Company plans to progress GMP work to the fullest extent possible during the COVID-19 crisis, recognizing that circumstances outside of the Company's control related to the pandemic could affect the timing of that work. In the event of a temporary work force reduction, the Company will continue GMP work that it is able to safely progress as staffing allows.

V. Distributed Energy Resources ("DERs")

A. Overview of DERs on the Distribution System

The Company currently has over 54,000 interconnected DER's on its system with a total nameplate capacity of 1,331 MW. The drivers of DERs continue to be state and federal incentives to promote renewable energy, utility tariffs that authorize net metering and virtual net metering, overall market developments, and reductions in cost of solar PV technology, among other factors. Many of the programs initiated to progress the market for DERs continue to incent the pursuit of DER interconnection requests. The Company currently has over 5,000 active applications representing an incremental 1.48 GW. Over 3,500 of the active applications were driven through the new SMART Program representing over 678 MW in the application process.

B. Lessons Learned Integrating DERs

The Company continues to progress and support requests for interconnections. While the Company continues to evolve its understanding of the dynamics and impacts of DERs on the distribution system, the following areas represent lessons that are being incorporated into the GMP.

LESSON: Planning and operating with intermittent loads requires upgraded modeling tools and systems.

As a result of DER complexities, existing planning tools and approaches are insufficient to incorporate the necessary forecast details. For example, the Company is moving away from consideration of distributed generation as a load adjustment and moving to independent forecasts and load cycles for DER technologies. These improved forecasts and load cycles will be used by planners and operators to plan and manage the more complex system. The data processing enabled by the sensors, communications, and back office IT infrastructure investments in this GMP will be instrumental in refining the load cycles to continuously improve the forecasts. Similarly, the control provided the ADMS, FLISR, and VVO/CVR investments will enable the management across the load cycles and forecasts for the variety of technologies.

LESSON: Thermal and voltage management becomes more complex.

Proper thermal and voltage performance is necessary to ensure the reliability of the electric distribution system. With widespread distributed generation and electric vehicle charging, loading and voltage becomes more dynamic over the course of a year. The technologies included in the GMP link directly to this DER integration issue. Assets such as capacitors will be installed with advanced controls and can be used not only for VVO program, but for better voltage management to enable DER. Similarly, ADA can be used not only for FLISR functionality, but for system rearrangement for thermal management. The sensing points provided by these advanced devices also plays an important role in voltage and thermal management.

Not only can DER have a complex effect on distribution voltage management, but in concentrated quantities can affect the transmission system as well. The transmission system can be affected under normal and contingency conditions. National Grid has begun to experience this exact risk with proposed high DG penetration areas in Western and Central Massachusetts. The large amounts of DG proposed in these areas were under study for potential transmission system impacts. In conjunction with traditional study efforts, the Company investigated redeployment of a modest amount of GMP advanced capacitors as a mitigation measure. Upon consideration of this redeployment of GMP resources, a subset of the DG was enabled to proceed without further transmission system impact analysis.

LESSON: Reverse power flow requires upgraded controls.

Reverse power flow has a significant impact on distribution and transmission electrical systems. For example, voltage regulators and transformer load tap changers undercorrect voltage levels under reverse power flow conditions. The controls for these devices must be upgraded to allow for bidirectional power flow. Similarly, protection devices have settings to isolate portions of the system during fault conditions. These settings are carefully selected to avoid mis-operation for high load levels yet to maximize protection speed. Reverse power flow can impact this balance and require devices that can accommodate reverse power flow settings. Additional impacts are described in the fault current section below.

The advancements in the GMP link directly to this DER integration issue. Regulator and transformer load tap changer control upgrades might be required as part of a VVO program. The upgraded controls would include reverse power functionality. Similarly, advanced reclosers would include primary and alternate settings capabilities. However, there is significant protection procedure analysis to be done before such functionality is enabled. Again, the sensing provided by a number of grid modernization assets will play an important role in identifying and managing the power flow direction at any given point in time.

LESSON: DER intermittency can lead to power quality/flicker issues.

A sudden drop in solar or wind resources due to changing weather characteristics can create power quality issues such as voltage flicker. As these resources become more concentrated the same cloud cover or wind drop can affect multiple generators compounding the impact. National Grid has created long-term dynamic analysis methods to best evaluate this problem, but has limited options to mitigate the voltage flicker.

The current GMP does little to mitigate this DER integration issue. The planned sensor response times are intended to address and inform on steady state system characteristics. Sub-second sensing for dynamic issues such as flicker would be a far term grid modernization concept.

However, the current GMP does provide a basis to integrate future technologies that could mitigate flicker such as smart inverters and paired energy storage.

LESSON: DER can affect fault current levels and fault current direction requiring complex analysis and complex protection systems.

Fault current is the level of current or power associated with a fault on the electric system. DER can change the fault levels and direction such that certain devices operate slower than intended which could lead to mis-operation or miscoordination. These existing protective devices must be changed or reset to reestablish proper coordination. It is anticipated that these devices will require multiple setting capabilities or adaptive setting capabilities.

Arc flash is a related phenomenon influenced by fault current levels and protection timing. Arc flash levels are assessed to evaluate the potential worker safety risks and are a key consideration in the development of personal protection equipment requirements and operating standards for utility and customer owned equipment. Distributed generators can change or split the direction of fault flow slowing down existing protection schemes. Cases where fault energy is increased and protection systems are desensitized or slowed present the greatest arc flash concerns. Furthermore, reanalysis may be necessary when certain size generators are interconnected or disconnected.

DER can also impact transmission ground fault detection. In certain system configurations, DER can remain energized following a transmission fault. This can lead to equipment damage and presents a safety concern. Zero sequence voltage protection (commonly referred to as "3V0") is required in order to detect and isolate this issue.

Similar to the reverse power flow discussion, the advancements in the GMP link directly to the DER integration issues described above. The advanced recloser controls would include primary/alternate settings and remotely programmable setting capabilities. Remotely programmable settings tied to an advanced control center management system is a step towards adaptive protection settings. However, there is significant protection procedure analysis to be done before such functionality is enabled. Lastly, grid modernization sensing which would inform the control center systems on connected DERs, and thereby inform on possible fault current levels will play an important role in developing the adaptive settings to send to the reclosers.

VI. METRICS

A. Description and Report on each Performance Metric

The Department stamp-approved the revised Performance Metrics on July 25, 2019, which the Company is reporting on in this Section.

2.1 VOLT VAR OPTIMIZATION AND CONSERVATION VOLTAGE REDUCTION BASELINE – The Company has not enabled VVO on circuits during the 2019 plan year and therefore has not established a baseline impact factor for each VVO enabled circuit which will be used to quantify the peak load, energy savings and greenhouse gas (“GHG”) impact measures.

2.2 VOLT VAR OPTIMIZATION (VVO) ENERGY SAVINGS - The Company has not enabled VVO on circuits during the 2019 plan year and has not established a baseline impact factor required to quantify the energy savings achieved by VVO.

2.3 VVO PEAK LOAD IMPACT - The Company has not enabled VVO on circuits during the 2019 plan year to quantify the peak demand impact VVO/CVR has on the system.

2.4 VVO – DISTRIBUTION LOSSES WITHOUT AMF (BASELINE) - The Company has not enabled VVO on circuits during the 2019 plan year.

2.5 VVO POWER FACTOR - The Company has not enabled VVO on circuits during the 2019 plan year.

2.6 VVO ESTIMATED VVO/CVR ENERGY AND GHG IMPACT - The Company has not enabled VVO on circuits during the 2019 plan year and therefore has not established a baseline impact factor for each VVO enabled circuit which will be used to quantify the overall GHG impact VVO/CVR has on the system.

2.7 INCREASE IN SUBSTATIONS WITH DISTRIBUTION MANAGEMENT SYSTEM (“DMS”) POWER FLOW AND CONTROL CAPABILITIES – The Company has not enabled DMS power flow capability during the 2019 plan year.

2.8 CONTROL FUNCTIONS IMPLEMENTED BY CIRCUIT (VVO, AUTO RECONFIGURATION) - The Company has not enabled DMS control functions during the 2019 plan year.

2.9 NUMBERS OF CUSTOMERS THAT BENEFIT FROM GMP FUNDED DISTRIBUTION AUTOMATION DEVICES - The Company has not enabled automation devices during the 2019 plan year.

2.10 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS' EFFECT ON OUTAGE DURATIONS - The Company has not enabled automation devices during the 2019 plan year.

2.11 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS' EFFECT ON OUTAGE FREQUENCY - The Company has not enabled automation devices during the 2019 plan year.

2.12 VVO RELATED VOLTAGE COMPLAINTS PERFORMANCE METRIC AND BASELINE - The Company has not enabled VVO on circuits during the 2019 plan year. The overall count of voltage complaints decreased from 2018 to 2019. For 2019 the amount of change from base line decreased from the change in baseline for 2018.

		Change in # of Voltage Complaints	
	Baseline*	2018	2019
EAST METHUEN	13	5	2
14-74L1	3	1	3
14-74L2	2	-2	-2
14-74L3	3	-1	-1
14-74L4	2	2	1
14-74L5	3	3	0
14-74L6	2	2	1
MAPLEWOOD	5	9	16
12-16W1	2	6	8
12-16W3	1	1	5
12-16W4	0	4	5
12-16W5	3	-2	-2
STOUGHTON	10	14	4
07-913W17	0	9	4
07-913W18	5	-4	-2
07-913W43	2	4	2
07-913W47	0	0	2
07-913W67	0	1	0
07-913W69	3	4	-2
total	28	28	22

*Baseline calculated using average from 2016 and 2017 data

App.C.1.0 NATIONAL GRID RELIABILITY-RELATED COMPANY-SPECIFIC - The Company has not enabled automation devices during the 2019 plan year.

B. Lessons Learned/Challenges and Successes

Please see Section VI.A, above.

C. **Hosting Capacity Analysis Update**

In their filed initial GMPs, the Company described investments that would support the development of hosting capacity maps. The Department, in limiting its approved GMP investments to grid-facing investments, did not authorize the inclusion of hosting capacity map-related investments in the GMPs.[9] Instead, the Department noted that it would open a separate proceeding into the investigation of cost-effective deployment of customer-facing grid modernization investments.[10] Accordingly, the Companies, following the issuance of the order, shifted their attention and resources to implementing their approved grid modernization investments.

In addition, the Act to Advance Clean Energy, St. 2018, c. 227, §18, requires the 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.

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 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 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.

Although the Companies' proposed hosting capacity investments were not approved as part of the 2018-2020 GMPs, the Company has progressed hosting capacity analyses. As described in the GMP, investments planned over the course of the 2018-2020 GMPs in system visibility and load flow model capabilities are required in order for the Companies to actively calculate and maintain detailed hosting capacity values.

National Grid has established a data portal, including a hosting capacity map. Approximately 97% of the circuits have been completed and published to the portal. There are 32 circuits, less than 3%, that will require additional work and are targeted for completion in March 2021. Tab 'Hosting Capacity Fdr Summ in the attached DPU Annual Report Template has the feeder level status.

---

[9] Order at 134, n. 70.

[10] Id. at 135.

VII. Research, Development and Deployment

An effective research and development ("R&D") program is a critical element supporting the development of a modern grid that progresses the Department's grid modernization objectives. While the Company's Research, Development and Deployment ("RD&D") proposals included in its filed GMP were not approved, the Company has continued to engage in research activities at similar levels as it has in the past outside of its GMP.

The company's R&D portfolio focuses on the advancement of technologies, processes, systems and work methods that are new and required for utility transformation in becoming a cleaner, more efficient and reliable grid. This is accomplished by working with internal organizations to identify R&D opportunities and needs of both the existing business practices as well as those of an envisioned utility of the future. Through its R&D plans, the Company seeks to (a) reduce the overall cost of delivering energy and optimizing its system demand, (b) include safety in the design process, (c) operate the network more efficiently by optimizing system performance, (d) facilitate the interconnection and integration of distributed energy resources and (e) enable a sustainable design. These goals are progressed through collaborating with innovation partners including government agencies, universities, technical organizations (e.g., the Electric Power Research Institute ("EPRI"), the Centre for Energy Advancement through Technological Innovation ("CEATI"), etc.), the vendor community, industry committees and establishing a greater international reach. To increase the impact of its R&D spending, the Company generally leverages its R&D investments in organizations that collaborate research among multiple utilities, and the Company may also seek government funding opportunities that align with its objectives.

The Company annually refines its R&D plan to align with developing needs. We continue to look at emerging challenges, including those related to distributed renewable resources and grid modernization.

Distribution efforts are managed by the Grid Modernization Solutions team within the Electric Business Unit and Transmission efforts are managed by the Asset Development team within the Transmission Business Unit. Direct cost to fund dedicated R&D project efforts are allocated to multiple operating companies within National Grid USA that benefit from these research efforts.

The Company continued participation in EPRI and CEATI programs and working groups throughout 2019. During 2019 the Company also received the following R&D Awards:

1) In February 2019, the Company received an EPRI Technology Transfer award, entitled Smart Inverter Requirements and Application, for our work on testing smart inverters' capabilities to improve grid reliability by mitigating the impact of renewable resources on secondary and primary system voltage. National Grid and EPRI filed a white paper titled

"RECOMMENDED SMART INVERTER SETTINGS FOR GRID SUPPORT AND TEST PLAN" to share the findings from the research.

2) In November 2019, the Company also received an award from Energy Storage North America (ESNA) for the deployment of a Tesla built 6MW / 48MWh energy storage system. This system along with a 15MW Combustion Turbine Generator creates a microgrid which aims to defer the expense of running a third undersea cable to Nantucket, while ensuring that the Island's electrical needs are meet for years to come. The system is being fitted with a predictive decision support system which will take weather, historical load, and several other parameters into account to control the energy storage system in a semi-autonomous fashion.