nationalgrid

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

Grid Modernization Plan Term Report Calendar Year 2018-2021

D.P.U. 22-41

April 1, 2022

Submitted to:
Massachusetts Department of Public Utilities

Grid Modernization Term Report Table of Contents

I Overview

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 would submit GMPs every three years, which would 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 would 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. In D.P.U. 15-120-D/15-121-2/15-122-D (May 12, 2020), the Department extended the first grid modernization plan investment term through calendar year 2021, and extended the deadline for the first Grid Modernization Term Report to April 1, 2022.

The Department has established the outline/table of contents to be included in the term report. D.P.U. 21-116, Hearing Officer Memorandum (February 15, 2022). The Department also has approved the metrics to be reported on in the annual and term reports. D.P.U. 15-120/15-121/15-122, Stamp Approval (July 25, 2019). The Department additionally has adopted templates to be completed and included with the term reports. D.P.U. 21-116, Hearing Officer Memorandum (February 15, 2022). This filing is National Grid’s first Grid Modernization Term Report, which contains the narrative documenting the Company’s performance on its Grid Modernization Plan for the time period January 1, 2018 through December 31, 2021 (“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 (subsequently extended to four years, through December 31, 2021). 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 during the first two GMPs only.

The Department preauthorized the following categories of grid-facing investments for a combined three-year (extended to four-year) budget of $82 million: (1) conservation voltage reduction/volt-VAR optimization ("CVR/VVO" or "VVO"); (2) advanced distribution automation ("ADA"); (3) feeder monitors ("FM"); (4) communications and information/operational technologies ("IT/OT"); and (5) advanced distribution management system/supervisory control and data acquisition system ("ADMS/SCADA"). The preauthorized investment categories incorporated the following investments:

(1) CVR/VVO - CVR/VVO technology flattens the voltage profile of a feeder by applying intelligent control to capacitors and regulators on the feeder which serves to minimize electrical losses, followed by lowering the source voltage at the substation to provide energy savings for both the utility and the customer. The Plan included deployment of this technology on sixteen feeders in the initial three-year period, and an additional sixteen feeders in the fourth year.

(2) ADA – The Company proposed to deploy ADA equipment designed to accomplish Fault Location, Isolation and Service Restoration ("FLISR"). 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. The Plan included deployment of this technology on sixteen feeders in the initial three-year period, and an additional thirty-two feeders in the fourth year.

(3) Feeder Monitors – The Company proposed to 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 Plan included deployment of this technology on one hundred and eighty feeders in the initial three-year period.

(4) Communications and IT/OT - A fundamental component of grid modernization is a systems architectural framework that can deliver "any data, any service, anytime." Building this technology foundation is at the infrastructure cornerstone for delivering the capabilities of the proposed grid modernization investments, including CVR/VVO, ADA, feeder monitors, ADMS/DSCADA, and integrating distributed generation ("DG"). The major components of the systems architectural framework are:
   a. Comprehensive Integration Services ("CIS") - The integration services to enable the exchange of information between systems, services and devices.
   b. Enterprise Analytics - The big data analytics capabilities to allow for the analysis of the data gathered from grid modernization investments combined with existing and third-party data sources, providing valuable output reflecting current state as well as predictive and prescriptive outcomes.
   c. Communications and Networking - A set of communication services that transfer information with the correct prioritization and quality of service to the appropriate destination.
   d. Integrated Network Operations Center ("INOC") - To actively monitor, manage and maintain the integrated set of services and infrastructure and provide a single point of contact for support and operations through a cross-functional set of people, processes and technologies.
   e. The Company has advanced an overall architecture assessment approach to support capability modeling to create robust long-term roadmaps. By using enterprise solutions, the Company can reduce the quantity of similar solutions, which in turn creates a more streamlined portfolio that reduces the overall costs to manage and maintain and build stronger technical and business capabilities to expand value to end customers. This will allow the Company to identify and invest in solutions that create long-term value and can be extended to meet the evolving needs and nature of technology. This enterprise architecture approach mitigates stranded costs typically experienced in "one-off" siloed solutions, and minimizes the expense, configuration and management complexity that individual built-to-purpose applications often experience. The enterprise services proposed as part of the GMP are aligned to this approach.

(5) ADMS/SCADA – The Company proposed a five-year deployment effort to implement an ADMS and distribution SCADA ("DSCADA") system to support the increased number of distribution devices (FLISR, CVR/ VVO, telecommunications and feeder monitors) proposed in the GMP (as well as distributed energy resources ("DERs")) to meet the requirements for grid modernization. In addition, an effort to modernize, ensure compatibility, and integrate the Company's geographic information system ("GIS") database will be required, in order to support the ADMS.

Pursuant to the Department's Order, the preauthorized budgets for the grid-facing investments, incorporate implementation of any incremental cybersecurity measures associated with these investments. Threats to the cybersecurity of critical infrastructures emanate from a wide spectrum of potential sources, including; state-sponsored espionage and sabotage, international terrorism, domestic militants, malevolent 'hacktivists' or even disaffected insiders. A reliable and secure grid is necessary to safely enable the grid-facing aspects of grid modernization, including limiting outages with a self-healing resilient transmission and distribution network, and other strategically important functions. Cybersecurity and privacy provisions will support the GMP by maintaining a reliable and secure electricity infrastructure and ensuring the protection needed for the confidentiality and integrity of the digital overlay.

A. Term 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, improved system operations and system planning, and increased DER integration capacity. 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 throughout the four-year plan period. In calendar year 2019, National Grid developed detailed plans for each investment area and has continued executing those plans through the end of 2021.

In mid-March 2020, with the onset of the global COVID-19 pandemic, the Company took immediate actions to protect the employees, customers and our energy delivery networks. This global event and the global response were unforeseen and required swift and immediate response, for which the Company invoked its Business Continuity Plans and Pandemic Plans. As a result the Grid Modernization program experienced several impacts including supply chain issues, workforce impacts, work plan changes, and prioritization of health and safety, reliability and essential customers. Calendar year 2020 also saw a significant increase in storms and our response which also impacted the grid modernization work plan in Massachusetts.

[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. Order at 105-106.

With respect to optimizing system performance, the Company completed planning and engineering efforts for the selection of locations for both feeder monitors and ADA. Once locations were identified and selected, the investments were progressed to the engineering design organization. The Company implemented a total of sixteen FLISR schemes for the term period, fourteen FLISR schemes that went live in 2021, and an additional two FLISR schemes that went live in 2020. The benefits of having live FLISR schemes is being realized as there were four FLISR events in calendar year 2021. All four events restored 35% or more customers under the one-minute Massachusetts threshold for frequency, and an additional three operations in early 2022 produced similar results.

The Company also completed analysis and identification of circuits to deploy VVO, which helps to optimize system demand. Once circuits were identified and selected, the investments were progressed to the engineering design organization. These investments have been under construction with investments being enabled starting in 2020 and through the first term period. The Company completed deployment and initiated measurement and verification on six feeders out of the Stoughton substation in 2020. The Company completed deployment and initiated measurement and verification on twenty-one additional feeders out of three substations in 2021.

National Grid completed a strategic assessment of the telecommunications and the IT/OT approach and finalized the portfolio of solutions for building this technology foundation and infrastructure cornerstone for delivering the capabilities of the grid modernization investments, including CVR/VVO, ADA, feeder monitors, ADMS/DSCADA, and integrating DG. As a component of the strategy, National Grid identified short-term and long-term plans for building the enabling capabilities, platforms and communications necessary to achieve visibility, control and operation of the first term investments. The Company completed and deployed the minimum viable product for the new telecommunications operations management system (TOMS) solution to design, manage and maintain our expanding telecommunications infrastructure in December 2021.

Lastly, the Company has progressed development and implementation of the ADMS/DSCADA platform, which supports all three Grid Modernization objectives. This includes progression of efforts to perform data model updates, data clean up and validation of the connected model within GIS to support ADMS requirements. The Company completed and deployed Phase 1 of the ADMS project in May 2021 and the GIS Phase 1 project in September 2021.

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

The Company progressed investments across all the approved categories throughout the four-year term. The plans developed were significantly impacted by the global COVID-19 pandemic in the first half of 2020, yet the Company was able to sustain progress and was successful in delivering many of the plans. Below is a summary of the key highlights with the supporting details contained in each investment Category within Section III.

VVO – The Company initiated VVO deployment in the first quarter of 2019 with the selection of substations and feeders to be upgraded with the new technology. Throughout the term, continual progress was made toward the goal of deploying VVO on 16 feeders contemplated as part of the initial 2018-2021 plan period. The Company also selected and progressed the design, construction and commissioning of an additional 23 feeders within this plan period. The Company completed deployment and initiated measurement and verification on six feeders out of the Stoughton substation in 2020. The Company completed deployment and initiated measurement and verification on twenty-one feeders out of three substations in 2021. The Company also installed, configured and commissioned the server that runs the VVO solution which manages the twenty-seven feeders. The Company initiated the planning, design and construction for an additional 12 VVO feeders across two additional substations. The Company completed the construction and commissioning of the remaining ten smart capacitor units to complete the ASO effort to facilitate the interconnection of distributed energy resources, and initiated efforts to incorporate these installations into a VVO software for enablement and measurement and verification during 2022.

ADA – The Company completed the eight FLISR schemes contemplated as part of the 2018-2021 plan period representing 33 reclosers, 16 feeders and 12 substations. The Company also completed an additional eight FLISR schemes representing 29 reclosers, 15 feeders and 13 substations. The design and construction activities for an additional 6 schemes were initiated in 2021, although there were delays incurred due to the COVID-19 pandemic. The Company completed construction and enablement of 14 schemes in 2021.

FM – The Company completed a planning assessment to prioritize the deployment of feeder monitors through the initial three-year period. Throughout the 2018-2021 plan period the portfolio of individual feeder monitors was progressed through the stages of planning and deployment including: location selection, preliminary engineering, sanctioning, design start, telecom cell strength verified, materials procured, construction started, and device commissioning. The Company progressed construction and commissioning of the 180 devices contemplated in the 2018-2021 plan period. A total of five feeder monitors were commissioned in 2019 and 66 feeder monitors in 2020. During 2021, the Company progressed the feeder monitor program construction and commissioning 84 additional feeder monitors.

ADMS - The Company has progressed several key activities throughout the term. The Company completed and deployed Phase 1 of the ADMS project in May 2021. This included change management work, operator / end user training, multiple testing phases, cutover, and post-deployment support. The Company has also initiated business capabilities and system requirements for Phase 2 of the ADMS project, working with our ADMS vendor to prepare test cases for future factory and site acceptance testing, and completed a review our of outage management business process and integration. The Company completed and deployed the GIS platform in September 2021 to: accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics; facilitate capture of greater data and modeling granularity for underground distribution networks; and facilitate more granularity for low-voltage secondary distribution networks. GIS and engineering data incorporation into ADMS for the load flow solution and Phase 1 solution was also enabled. User training, business acceptance and phase 1 system go live was completed. The Company has also continued the GIS system and data enhancements work to improve data quality and define new attributes for the connected data model. As part of the overall ADMS work stream, the Company completed nineteen locations for Remote Terminal Unit ("RTU") separation work through the end of 2021.

Communications and IT/OT – Building upon the work started in 2019, the Company advanced an overall architecture assessment approach to support the capability modeling to create robust long-term roadmaps. This allowed the Company to identify and invest in solutions that create long-term value and can be extended to meet the evolving needs and nature of technology. During the plan period, the Company completed and deployed initial phases and solutions for data management and analytics and the comprehensive integration services. The Company completed and deployed the minimum viable product for the new telecommunications operations management system (TOMS) solution to design, manage and maintain our expanding telecommunications infrastructure in December 2021. This included deployment of software and associated licenses for Enterprise Analytics Phase 1 focused on deploying a centralized electric distribution data repository to support grid modernization in June 2021. In addition, deployment of software and associated licenses for the Enterprise Integration Platform Phase 1 in November 2021, which included the setup of the core platform which is the foundation on which the integrations to enable grid modernization was delivered. Multiple environments to support development, test and production have been provisioned, and integration work in support of the GIS Phase 1 and the ADMS Phase 1 projects are complete. The Company completed and deployed the minimum viable product for the new telecommunications operations management system (TOMS) solution to design, manage and maintain our expanding telecommunications infrastructure in December 2021.

The Company provided the required format for the annual reporting of the system-level deployment and spending information in each annual report. The baseline plan summary was provided in Tab 5.a. Spending - 2018 Report in the attached DPU Annual Report Template. The Company has provided the summary of planned versus actual deployment of devices and spending as of December 31, 2021 in Tab 5.d. Spending - 2021 Report in the attached DPU Annual Report Template. Refer to columns D-L.

Grid Modernization - Total Deployment Plan (Units)				
	Commissioned Units			
Investment Areas and Preauthorized Device Types	**2018-2021 Actual**	**2018-2021 Plan**	**2018-2021 Variance (Units)**	**2018-2021 Percent (%)**
Monitoring & Control (SCADA)	**155**	**197**	**(42)**	**78%**
Feeder Monitors	155	197	(42)	78%
Distribution Automation	**100**	**101**	**(1)**	**98%**
OH DA w/Ties	21	20	1	105%
OH DA w/out Ties	61	58	3	105%
Feeder Monitors	18	23	(5)	78%
Volt-Var Optimization	**202**	**243**	**(41)**	**83%**
VVO - Regulators	45	48	(3)	94%
VVO - Capacitor Banks	114	141	(27)	81%
VVO - LTC Controls	13	11	2	118%
VVO - Line Sensors	30	43	(13)	70%
Total Units	**457**	**541**	**(84)**	**84%**

C. Summary of Term Spending (Actual v. Planned)

The Department approved a budget of up to $82 million in incremental spending for grid-facing investments over three years (extended to four 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 Department extended the initial plan period from three to four years in D.P.U. 15-120-D/15-121-2/15-122-D (May 12, 2020), extending the first grid modernization plan investment term

[2] Order at 221-222.
[3] Id.

through calendar year 2021. The Company maintained delivery of key investments while remaining within the Department's spending allowance.

The Company filed its documentation for its incremental O&M costs for its GMP in plan year 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 GMF filing on March 15, 2020. The Company included these costs with the costs for plan year 2019 for recovery through the GMF that the Company filed on March 15, 2020 that went into effect beginning May 1, 2020 in D.P.U. 20-31. The plan year 2019 spending included costs for cybersecurity, ADA, ADMS, Feeder Monitors, VVO, GIS, and telecommunications. The Company also included costs associated with managing and delivering the portfolio, required change management and the evaluation plan.

The plan year 2020 spending includes costs for cybersecurity, ADA, ADMS, Feeder Monitors, VVO, GIS, and communications and IT/OT. The Company also included costs associated with managing and delivering the portfolio, required change management and the evaluation plan. The Company spent approximately $33 million in 2020 against an initial plan estimate of approximately $38 million. The Company also placed approximately $8.7 million of plant in service against the initial plan of approximately $14 million. While below our initial plans, the aforementioned impacts from the COVID-19 pandemic were the primary drivers for the variation.

The plan year 2021 spending includes costs for cybersecurity, ADA, ADMS, Feeder Monitors, VVO, GIS, and communications and IT/OT. The Company also included costs associated with managing and delivering the portfolio, required change management and the evaluation plan. The Company spent approximately $30 million in 2021. The Company also placed approximately $31 million of plant in service.

As requested in the Hearing Officer Memorandum issued on March 11, 2021, the Company is including the capital and O&M costs for the plan years 2018-2021. These can also be found in Tab 5.e Spending – Cumulative in the attached Department Annual Report Template. The Company had represented Total Spending to include both capital and O&M for prior reporting periods. The capital investments for the ADMS and Communications / IT/OT contain certain investments that are to be deployed across Massachusetts and New York. The shared investment will be allocated using National Grid's standard allocation factors, and the costs presented in the table are the amounts estimated to be allocated to Massachusetts based on the allocation factors in effect as of March 31, 2021.

		Capital Spending ($)				
		2018	2019	2020	2021	Cumulative
Investment Category	Charge Types	Actual	Actual	Actual	Actual	Actual
Monitoring & Control (SCADA)	Labor		$ 36,190.68	$ 341,326.61	$ 343,765.30	$ 721,282.59
Monitoring & Control (SCADA)	Non Labor		$ 189,598.89	$ 2,116,951.39	$ 2,141,800.42	$ 4,448,350.70
Monitoring & Control (SCADA)	**Total**		**$ 225,789.57**	**$ 2,458,278.00**	**$ 2,485,565.72**	**$ 5,169,633.29**
Distribution Automation	Labor		$ 87,025.66	$ 487,967.74	$ 719,195.61	$ 1,294,189.01
Distribution Automation	Non Labor		$ 315,077.67	$ 2,864,977.62	$ 4,556,684.26	$ 7,736,739.55
Distribution Automation	**Total**		**$ 402,103.33**	**$ 3,352,945.36**	**$ 5,275,879.87**	**$ 9,030,928.56**
Volt-Var Optimization	Labor		$ 155,864.51	$ 1,410,750.28	$ 1,033,768.05	$ 2,600,382.84
Volt-Var Optimization	Non Labor		$ 1,398,504.62	$ 7,995,450.67	$ 4,025,529.96	$ 13,419,485.25
Volt-Var Optimization	**Total**		**$ 1,554,369.13**	**$ 9,406,200.95**	**$ 5,059,298.01**	**$ 16,019,868.09**
Advanced Distribution Management System (ADMS)	Labor		$ 75,602.96	$ 906,823.44	$ 685,478.63	$ 1,667,905.03
Advanced Distribution Management System (ADMS)	Non Labor		$ 88,988.98	$ 6,547,023.36	$ 6,231,390.35	$ 12,867,402.69
Advanced Distribution Management System (ADMS)	**Total**		**$ 164,591.94**	**$ 7,453,846.80**	**$ 6,916,868.98**	**$ 14,535,307.72**
Communications and IT/OT	Labor		$ 9,284.41	$ 182,458.86	$ 484,259.19	$ 676,002.46
Communications and IT/OT	Non Labor		$ 66,493.59	$ 1,644,845.48	$ 5,120,008.34	$ 6,831,347.41
Communications and IT/OT	**Total**		**$ 75,778.00**	**$ 1,827,304.34**	**$ 5,604,267.53**	**$ 7,507,349.87**
Workforce Management	Labor					$ -
Workforce Management	Non Labor					$ -
Workforce Management	**Total**					**$ -**
Electric Vehicles	Labor					$ -
Electric Vehicles	Non Labor					$ -
Electric Vehicles	**Total**					**$ -**
Energy Storage	Labor					$ -
Energy Storage	Non Labor					$ -
Energy Storage	**Total**					**$ -**
Total Grid Modernization	Labor	$-	$ 363,968.22	$ 3,329,326.93	$ 3,266,466.78	$ 6,959,761.93
Total Grid Modernization	Non Labor	$-	$ 2,058,663.75	$ 21,169,248.52	$ 22,075,413.33	$ 45,303,325.60
Total Grid Modernization	**Total**	**$-**	**$ 2,422,631.97**	**$ 24,498,575.45**	**$ 25,341,880.11**	**$ 52,263,087.53**

		O&M ($)				
		2018	2019	2020	2021	Cumulative
Investment Category	Charge Types	Actual	Actual	Actual	Actual	Actual
Monitoring & Control (SCADA)	Internal O&M (labor-related)		$ 166,520.26	$ 171,943.11	$ 141,586.73	$ 480,050.10
Monitoring & Control (SCADA)	External contractor expense		$ 1,229.35	$ 16,928.78	$ 31,043.68	$ 49,201.81
Monitoring & Control (SCADA)	**Total**	$-	**$ 167,749.61**	**$ 188,871.89**	**$ 172,630.41**	**$ 529,251.91**
Distribution Automation	Internal O&M (labor-related)		$ 29,615.85	$ -	$ 54,134.25	$ 83,750.10
Distribution Automation	External contractor expense		$ 30,316.78	$ 7,860.47	$ 61,160.87	$ 99,338.12
Distribution Automation	**Total**	$-	**$ 59,932.63**	**$ 7,860.47**	**$ 115,295.12**	**$ 183,088.22**
Volt-Var Optimization	Internal O&M (labor-related)		$ 231,905.95	$ 145,242.26	$ 169,196.14	$ 546,344.35
Volt-Var Optimization	External contractor expense		$ 52,899.26	$ 153,512.17	$ 81,725.77	$ 288,137.20
Volt-Var Optimization	**Total**	$-	**$ 284,805.21**	**$ 298,754.43**	**$ 250,921.91**	**$ 834,481.55**
Advanced Distribution Management System (ADMS)	Internal O&M (labor-related)		$ 85,139.36	$ 354,180.80	$ 419,033.50	$ 858,353.66
Advanced Distribution Management System (ADMS)	External contractor expense		$ 471,860.62	$ 2,619,437.17	$ 1,743,762.69	$ 4,835,060.48
Advanced Distribution Management System (ADMS)	**Total**	$-	**$ 556,999.98**	**$ 2,973,617.97**	**$ 2,162,796.19**	**$ 5,693,414.14**
IT/OT	Internal O&M (labor-related)			$ 119,004.13	$ 289,205.32	$ 408,209.45
IT/OT	External contractor expense	$ 98,394.95	$ 1,763,499.27	$ 2,271,935.25	$ 825,197.61	$ 4,959,027.08
IT/OT	**Total**	**$ 98,394.95**	**$ 1,763,499.27**	**$ 2,390,939.38**	**$ 1,114,402.93**	**$ 5,367,236.53**
Admin & Regulatory	Internal O&M (labor-related)		$ 111,770.44	$ 153,889.40	$ 202,167.24	$ 467,827.08
Admin & Regulatory	External contractor expense		$ 1,195,164.27	$ 1,638,954.09	$ 716,767.25	$ 3,550,885.61
Admin & Regulatory	**Total**	$-	**$ 1,306,934.71**	**$ 1,792,843.49**	**$ 918,934.49**	**$ 4,018,712.69**
Electric Vehicles	Internal O&M (labor-related)					$ -
Electric Vehicles	External contractor expense					$ -
Electric Vehicles	**Total**	$-	$-	$-	$-	$ -
Energy Storage	Internal O&M (labor-related)					$ -
Energy Storage	External contractor expense					$ -
Energy Storage	**Total**	$-	$-	$-	$-	$ -
Total Grid Modernization	Internal O&M (labor-related)	$ -	$ 624,951.86	$ 944,259.70	$ 1,275,323.18	$ 2,844,534.74
Total Grid Modernization	External contractor expense	$ 98,394.95	$ 3,514,969.55	$ 6,708,627.93	$ 3,459,657.87	$ 13,781,650.30
Total Grid Modernization	**Total**	**$ 98,394.95**	**$ 4,139,921.41**	**$ 7,652,887.63**	**$ 4,734,981.05**	**$ 16,626,185.04**

	Capital and O&M				
	2018	2019	2020	2021	Cumulative
Investment Category	Actual	Actual	Actual	Actual	Actual
Monitoring & Control (SCADA)	$	$ 393,539.18	$ 2,647,149.89	$ 2,658,196.13	$ 5,698,885.20
Distribution Automation	$	$ 462,035.96	$ 3,360,805.83	$ 5,391,174.99	$ 9,214,016.78
Volt-Var Optimization	$	$ 1,839,174.34	$ 9,704,955.38	$ 5,310,219.92	$ 16,854,349.64
Advanced Distribution Management System (ADMS)	$	$ 721,591.92	$ 10,427,464.77	$ 9,079,665.17	$ 20,228,721.86
Communications	$ 98,394.95	$ 1,839,277.28	$ 4,218,243.77	$ 6,718,670.46	$ 12,874,586.46
Electric Vehicles	$	$	$ -	$ -	$ -
Workforce Management	$	$	$ -	$ -	$ -
Energy Storage	$	$	$ -	$ -	$ -
Admin & Regulatory		$ 1,306,934.71	$ 1,792,843.49	$ 918,934.47	$ 4,018,712.67
Total Grid Modernization	**$ 98,395**	**$ 6,562,553.39**	**$ 32,151,463.13**	**$ 30,076,861.14**	**$ 68,889,272.61**

The Company provided the required format for the annual reporting of the system-level deployment and spending information in each annual report. The baseline plan summary was provided in Tab 5.a. Spending - 2018 Report in the attached DPU Annual Report Template. The Company is providing the term summary of planned versus actual spending as of December 31, 2021 in Tab 5.e. Spending – Cumulative in the attached Department Annual Report Template. Refer to columns D-L.

D. Significant Term Cost Variances

The overall term costs were below the projected spending. Tab 5.e. Spending – Cumulative in the attached Department Annual Report Template summarizes the revised planned spending over the initial plan periods and the final cumulative spend. Refer to columns D-L. The main contributors for changes from its original projections for its GMP expenditures and deployment for the 2018-2021 term include: (1) a longer than planned timeline to hire and mobilize incremental resources; (2) longer than anticipated materials lead times; (3) extended period for scoping and requirements for the ADMS project; 4) impacts related to the COVID-19 pandemic which started in March 2020; 5) work plan impacts due to the excessive number of storms in 2020; and 6) variances in estimates against actuals. Additionally, the first year of the GMP (CY 2018) was not a full calendar year, but rather began in May 2018 after the issuance of the D.P.U. 15-120/15-121/15-122 Order.

VVO – The primary cause of cost variance was the underestimation of the project activities. During the first two years of the program, underestimations in both the substation scope of work and distribution line equipment installation led to cost variances. The VVO E. Bridgewater, funding projects C084475 and C084476, required additional equipment, required additional substation work, and additional costs to upgrade software communication packages. The VVO Maplewood 16, funding projects C083420 and C083421, had underestimated labor charges for labor burdens, workforce training and support, and capital overhead charges. The MA VVO Stoughton, funding projects C083252 and C083253, required additional equipment, additional substation work, and additional costs to upgrade software communication packages. The MA VVO E Methuen, funding projects C083529 and C083530, required additional equipment, and additional costs were incurred to upgrade software communication packages for the new equipment to communicate with existing equipment.

ADA – The Quincy Reconductoring ADA Program, funding project C085009, incurred additions to the scope of work that included civil work requiring specialized equipment for removal, petitions for pole installs causing delays in schedule and underestimated labor and capital overhead charges for contractors. These additions to the scope and the scheduling delays are the result of the cost variance from the initial planned work and costs. Furthermore, these additions caused crews to extend mobilization and demobilization sites to increase costs for the work to be completed in a timely manner to reduce impacts of the schedule delays.

FM – The primary drivers for the cost variances are impacted by the individual installations and are primarily related to incremental make ready work, additional overhead costs, and additional labor to complete the work. Additional overhead costs include: pole replacements, existing equipment removal/ transfer, and scope variations unaccounted for in design. There was also an underestimation on initial cost per feeder monitor install.

ADMS – Planned spending was below initial estimates. National Grid performed an organizational realignment to ensure related transformational programs (which included ADMS) 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 and use case alignment, 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 were completed. Additionally, other drivers of reduced spending were favorable vendor contracts for hardware and software, reduced travel by internal and external labor due to Covid-19 restrictions, and a delay of hardware receivables due to Covid-19 supply chain constraints.

Communications and IT/OT – At the beginning of calendar year 2020, the Company revisited the priorities and needs for the Communications and IT/OT investment area. Based upon a review of the planning work performed in 2019 and the initial enterprise architecture assessment, the Company revised the priorities to deliver on the initial grid modernization plan investments and objectives. Specifically, it decided to defer significant investments in private fiber expansion for the initial plan period and focus on further developing the field area network ("FAN") and wide area network ("WAN") solutions. Furthermore, development and implementation of the Telecommunications Operations Management System ("TOMS") solutions will deliver greater capabilities and cost efficiencies over the longer term for progressing FAN and WAN expansion as well as provide the Operations groups increased capability to manage, maintain and troubleshoot the growing communications network. The Company also prioritized the IT investments for the comprehensive integration service and an enterprise analytics (EA) platform to deliver enabling capabilities and efficiencies in support of the foundational efforts.

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 investment areas approved in the Order. This organization performs the functions of a project management office and manages the overall delivery of services which includes: portfolio management and reporting, business process design and requirements definition, solution architecture, requirements management, change management, testing management, training and transfer planning and coordination, deployment operations, vendor technical implementation coordination and performance monitoring and reporting.

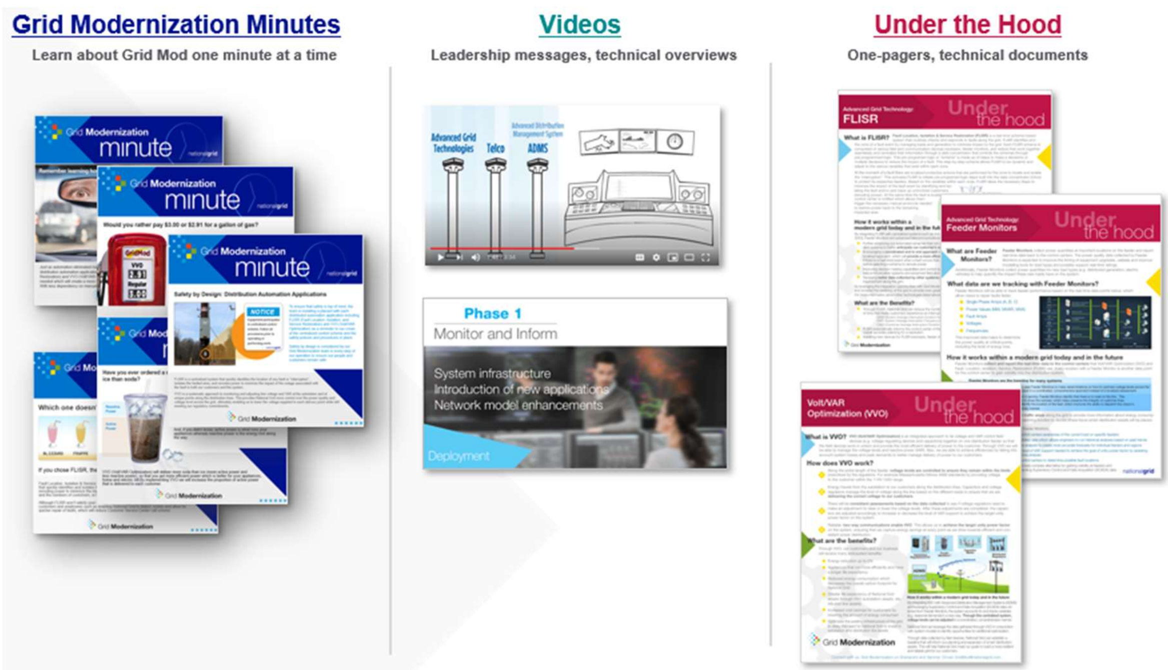
The Company implemented a cross-functional Steering Committee to provide guidance and oversight of the GMP implementation process. The Steering Committee includes representation from Engineering Asset Management and Planning, Information Technology, Electric Control Centers, Regulatory, Finance and Budgeting. The Steering Committee provides oversight for budget and implementation of the GMP investments, facilitates appropriate functional support and staffing, and champions program activities.

The Company has organized delivery of the core grid modernization investments, initiatives and capabilities into the following areas listed below: 1) Physical Infrastructure, 2) Advanced Distribution Management System, 3) Grid and Network Communications, 4) Program and Change Management, and 5) IT enabling platforms.

Physical Infrastructure (sensing & operating)	Advanced Distribution Management System	Grid and Network Communications	PMO, Change and Data Management	Information Technology Enabling Platforms
What's included: ▪ VVO/CVR ▪ Distribution Automation ▪ Feeder Monitoring Sensors	**What's included:** ▪ ADMS ▪ DSCADA ▪ DERMS (future project) ▪ GIS ▪ RTU	**What's included:** ▪ TOMS ▪ DMX ▪ INOC ▪ Network Tiers ▪ Lab	**What's included:** ▪ Project Financial Controls ▪ Project Management Office ▪ Data Management ▪ Regulatory Reporting and Metrics ▪ Change Management	**What's included:** ▪ Comprehensive Integration Services ▪ Data Management/Enterprise Analytics ▪ Cybersecurity
Type of work: ▪ Primarily consists of installation and commissioning of new field devices for sensing and automated field operation	**Type of work:** ▪ Implement new ADMS, upgrade and integrate GIS systems, perform network data cleanup and incorporate advanced applications	**Type of work:** ▪ Provide a reliable, cost-effective two-way communications capability to end devices and the capability to manage, maintain and troubleshoot the communications network.	**Type of work:** ▪ Drive successful program delivery in accordance with business management system and project management principles	**Type of work:** ▪ Investments integrating portfolio of GM systems, comprehensive data management, cybersecurity and data analytical functions.
Scope of the work: ▪ Feeder Monitors ▪ Advanced capacitors and regulators for voltage optimization ▪ Advanced reclosers to enable FLISR	**Scope of the work:** ▪ Implement ADMS Phase 1 platform ▪ GIS data model, attribute and cleanup ▪ Advanced Applications ▪ Advanced Load Flow ▪ RTU dual porting	**Scope of the work:** ▪ Wide Area Network, Field Area Network ▪ Network and operational management systems ▪ Network deployment and support	**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	**Scope of the work:** ▪ Implement integration services platform ▪ Implement data management and analytics platform ▪ Deliver cybersecurity services
IT and Cyber involvement: ▪ IT: Low to Medium ▪ Cyber: Medium	**IT and Cyber involvement:** ▪ IT: High ▪ Cyber: High	**IT and Cyber involvement:** ▪ IT: High ▪ Cyber: High		**IT and Cyber involvement:** ▪ IT: High ▪ Cyber: High
Responsibilities of Grid Mod team: ▪ Project Management ▪ Technical support (engineering) ▪ Field coordination ▪ Standards development ▪ Training and support	**Responsibilities of Grid Mod team:** ▪ Project Management ▪ Business requirements ▪ Technical Architecture ▪ Solution Design and Delivery ▪ Deployment and Support ▪ Change management	**Responsibilities of Grid Mod team:** ▪ Project Management ▪ Business requirements ▪ Operational Telecom Services	**Responsibilities of Grid Mod team:** ▪ Regulatory filings ▪ Steer Co and Mgmt reporting ▪ Program Controls and Assurance ▪ Business Readiness and Change	**Responsibilities of Grid Mod team:** ▪ Project Management ▪ Business requirements ▪ Technical Architecture ▪ Solution Design and Delivery ▪ Deployment and Support
Dependencies: ▪ Limited	**Dependencies:** ▪ GIS ▪ RTU	**Dependencies:** ▪ Alignment with broader organizational telecom strategy	**Dependencies:** ▪ Adherence to company frameworks and practices	**Dependencies:** ▪ Business engagement

The Company incorporated existing business frameworks and practices and leveraged the existing capabilities, processes, procedures, departments and personnel to support delivery of the GMP. This approach promotes early adoption and consistency across the enterprise with the ability to engage and enable the organization to deliver and ultimately scale and sustain the GMP portfolio. Using a matrix approach leverages a combination of internal and contracted operational personnel, such as line workers, technicians, IT developers, and engineers.

In order to instill support for grid modernization activities across the organization, the Company has progressed the change management capability leveraging the outcomes from the 2019 Workforce Management Survey. During 2020, the Company developed materials and information and engaged the broader organization through virtual staff meetings and change networks. These include Grid Modernization videos, one-pagers, Grid Modernization Minutes, and success stories.



During 2021, the Grid Modernization Execution team scaled the change management and outreach efforts to help impacted employee groups adopt the changes to their jobs. To effectively address the impacts on the affected cross-functional employee groups, the change management team engaged in a layered approach to:

- Execute on a comprehensive communications plan for reaching employees, multiple times across channels.
- Build resources, online trainings, and learning tools for individual and group use.
- Establish lunch and learns, team check-ins and build on all-hands meeting events as engagement and networking opportunities.

By the end of 2021, the Grid Modernization Execution team hosted a total of seven events throughout the year attended by 1,300+ stakeholders, with 96% of responding attendees rating the all-hands events good or better in survey responses. Additionally, highly impacted employees from across the electric organization were reached through multiple channels (e.g. emails, enterprise communications, newsletters) with project updates and training opportunities.

Below is a cross-section landscape sample of solutions and support resources made available for the Grid Modernization Execution stakeholders and impacted employee groups.

1. Description of staffing strategy implemented, and lessons learned, including but not limited to

In order to determine the needs for delivery of investments, training, ongoing support and maintenance, and incremental resources required by grid modernization, National Grid considered the needs within each of the approved investment areas of its GMP. Information from the prior SES Pilot was incorporated, as well as past experience with project rollouts and significant change management efforts. These provided the basis of the analysis and shaped recommendations about whether to propose contractor or new Company resources.

The results of the Company's high-level analysis indicated the need for a blend of both contractor and incremental resources to both develop and deliver technical and process content, and to drive delivery and to operate successfully new grid modernization technologies and systems and to enable new ways of working in this modernized environment. Personnel supporting the GMP fulfilled a variety of needs in the GMP including: network planning to determine where smart devices are most beneficial; engineering design and support services; technology delivery; and program management.

The Company delivered training in the most efficient and cost-effective manner possible by incorporating necessary changes into ongoing refresher training and existing curriculums where possible. Training was held either at centralized training facilities or at Company field offices, operating locations, depending on which location made the most sense for delivery of training.

Additional contractor and National Grid FTEs supported the grid modernization initiatives by providing services including program management, change management, engineering services, construction, and analytical/systems support. In addition, the Company continued to identify and deploy process improvements and implement effective change management as part of the GMP. The Company 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 program. New roles were identified during the planning and design phases of the projects 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 were completed.

The Company has 41 positions focused on delivery of the Grid Modernization program across three organizations, Grid Modernization Execution, ADMS and Grid Modernization Information Technology. These positions support Massachusetts as well as other jurisdiction grid modernization delivery. The staffing is comprised of a mix of existing NG employees (non-incremental) and new hires (incremental) to fill specific roles. Contractors also fill roles as needed. The Company also leverages existing business frameworks and practices and leverages the existing capabilities, processes, procedures, departments and personnel to support delivery of the GMP. This approach promotes early adoption and consistency across the enterprise with the ability to engage and enable the organization to deliver and ultimately scale and sustain the GMP portfolio. Using a matrix approach leverages a combination of internal and contracted operational personnel, such as designers, line workers, technicians, IT developers, and engineers. There are also a number of other organizations that have employees working partially to support grid modernization tasks, but they do not necessarily charge their time to grid modernization accounting. Examples of employees/groups working partially include but are not limited to capital planning, finance support, regulatory support, legal support, higher level management.

Total incremental labor associated with the Massachusetts GMP implementation by plan year, is provided on the following two tables reported in labor dollars and in FTE equivalents.

O&M	2019	2020	2021
Incremental Labor Cost	$380,451.54	$566,533.60	$734,920.71
Incremental Labor Hours	8,228.92	12,109.79	15,051.37
FTE Equivalents	4.2	6.18	7.68

Capital	2019	2020	2021
Incremental Labor Cost	$363,968.22	$3,329,326.93	$3,266,466.78
Incremental Labor Hours	11,438.54	72,856.30	68,217.53
FTE Equivalents	5.84	37.17	34.8

The Company did experience significant challenges during 2020 by the ongoing novel coronavirus, COVID-19, pandemic response. The Company initially established plans to safely progress work during the pandemic and provided the Department the Company's Business Continuity Plans for this event. The Company sought 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 affected the timing of that work. The more significant challenge was the impact to initial plans due to COVID-19 Guidelines and prioritization of essential maintenance to enable the regional shift to work from home for our customers. A lesser but still important to note impact is also quarantine time of all resources exposed to the COVID-19 virus and work-location shut downs that came from localized incidence of infection in smaller work locations. A proactive Company stance on safety as well as new IT access tools allowed for the transition to work from home during the pandemic. Although remote connection to systems and logistics surrounding remote work does create some challenges from an efficiency standpoint the Company was able to pivot and come up with multiple options to support continued progress on the program implementation, much done remotely, during the COVID-19 pandemic.

B. Cost and Performance Tracking Measures Adopted

1. Description of tracking measures adopted, including but not limited to

The Company has developed protocols and measures for identifying and tracking incremental capital and O&M expenses. Cost centers were set up within the Company's reporting hierarchy for Grid Modernization to specifically track program costs associated with the Grid Modernization organizations and Program costs. The Company has grid modernization-specific work orders to distinguish the preauthorized grid modernization investments within its accounting system. Costs associated with Program implementation are tracked using unique funding projects and work orders for capital, and internal orders for O&M. Capital is classified as either direct (operating company) or benefitting multiple companies (Service Company). O&M work that benefits one jurisdiction is direct charged to specific grid modernization orders/accounting for that jurisdiction. Work that benefits more than one jurisdiction is charged to orders that allocate the costs based on predetermined allocators. 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. Incremental labor is captured, and a review of all labor charged to Grid Mod capital and O&M accounting is completed at the end of each plan year. All capital costs, including labor, are considered incremental. For O&M costs, each employee's role, percentage of time spent on Grid Mod activities, and hire date are considered in determining which labor is incremental.

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 manages cost and performance tracking and controls through the Grid Modernization Execution organization.

The Company has adopted and provided both infrastructure and performance metrics described later in this Report. The EDCs have also supported and progressed the Evaluation Plan, which will be formally filed in June 2022.

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 and IT 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.

The adopted cost and performance tracking measures allowed for greater clarity and visibility of GMP related investments which allowed for collection and management of the investments for cost recovery tracking and annual reporting.

2. Narrative on ease of integration of Program cost tracking measures with existing practices, efficiency of separate tracking, and lessons learned

The Company implemented program cost tracking mechanisms to report on portfolio performance and ensure the accuracy of the cost data. This included aligning cost tracking within the overall financial process as well as the established program cost tracking process described above. This required managing the cost tracking across both a fiscal and calendar year reporting process. The Company reviews and assesses the reported cost data through the work order process to track GMP portfolio operational performance and analyze GMP work order activity.

The reporting combines both financial and operational metrics of the GMP portfolio. Operational work order details are formally tracked using this reporting. Work order detail, including but not limited to, work order description, service center, costs and work order status are pulled into the reports from various systems. Data is organized by project and by the GMP-specific lines of business discussed above in the GMP Accounting Process section. Any identified inconsistencies are addressed and corrected in a timely manner.

As a further review of the data, weekly meetings are held with project managers. The summarized GMP data, as well as detailed data from the tracking mechanism, is shared and analyzed during this meeting. In addition, the Grid Modernization Portfolio Manager shares additional information related to the program, such as program risks, issues, and progress towards internally established targets. The Grid Modernization Project Managers also report on progress made for their respective areas of responsibility. The weekly meetings provide a recurring opportunity and platform to discuss any issues related to or potentially impacting the GMP.

Informal processes also exist outside of the formal tracking reports and weekly meetings. Distribution Planning, Design, Scheduling, Engineering, Procurement, Corporate Performance Management, and other functional groups across the Company are in constant communication regarding all aspects of Company business, including the implementation of the GMP. Representatives of these various departments work cross functionally and collaboratively to meet GMP portfolio performance expectations. Stakeholders within these various department also maintain their own tracking mechanisms, which are cross checked periodically to the formal GMP source document maintained by the Grid Modernization Program team.

III. Term Implementation System Level Narrative by Investment Category

The Department preauthorized the following categories of grid-facing investments for a combined three-year (extended to four-year) budget of $82 million: (1) CVR/VVO; (2) ADA; (3) feeder monitors; (4) communications and IT/OT; and (5) ADMS/SCADA.[4] National Grid's cost estimates for the enabling infrastructure included: (1) a proposed budget of $48.4 million for ADMS/SCADA; and (2) a proposed budget of $1.8 million for communications and IT/OT.[5] National Grid's cost estimates for the field deployments included: (1) $10.6 million for deployment of VVO; (2) $13.4 million for deployment of ADA; and (3) $8 million over feeder monitors.[6]

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

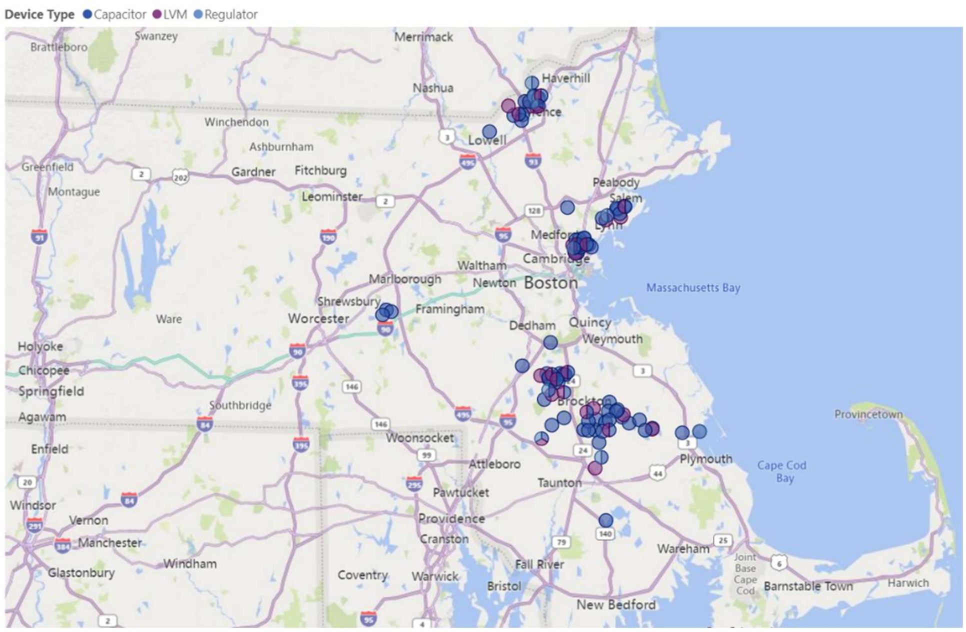
- They optimize system performance by providing automated outage and restoration notifications, assisting with determining outage locations and damage, and automatically rerouting power during outages in order to minimize the number of customers impacted and the length of outages. The ADA program is specifically designed to significantly reduce the minutes of interruption experienced by customers 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.
- They 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.
- They 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. The ADMS/DSCADA investments will enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.

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

A. (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. Additional benefits of VVO include improved equipment reliability and increased visibility of real time system performance.

<u>Installed VVO Devices</u>



1. Performance on implementation/deployment

The 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. Since the initial 3 substations/20 feeders were selected in 2019, an additional 3 substations/19 feeders in 2020 and 3 substations/15 feeders in 2021 were selected for VVO upgrades. The Company has been making continual progress on the deployments. The table below provides details of the equipment deployments in support of the VVO investments.

Progress of Equipment Installations to support VVO Investment

Work initiated in 2019

Substation	Year Work Completed	# Feeders	Cap Banks	Regulators	Feeder Monitors	Substation Bus
East Methuen	2021	6	19	12	6	2

Maplewood	2021	8	32	15	9	2
Stoughton	2020	6	18	3	6	1
		20	**69**	**30**	**21**	**5**

Work initiated in 2020

Substation	Year Work Completed	# Feeders	Cap Banks	Regulators	Feeder Monitors	Substation Bus
East Dracut	2022*	6	19	6	8	2
West Salem	2022*	6	23	3	7	2
East Bridgewater	2021	7	28	6	7	2
		19	**70**	**15**	**22**	**6**

Work initiated in 2021

Substation	Year Work Completed	# Feeders	Cap Banks	Regulators	Feeder Monitors	Substation Bus
Melrose	2022*	5	24	9	8	5
Westboro	2022*	5	17	3	7	5
Easton	2022*	5	19	3	5	1
		15	**60**	**15**	**20**	**11**
	Total:	54	199	60	63	22

* Planned completion year

The VVO implementation process involves several stages and multiple departments throughout the Company, as follows:

- Design and Work Request preparation: Distribution Planning and Asset Management, Distribution Design, Substation Engineering and Design departments
- Material Ordering and Preparation: Material Planners, Material Handlers, Resource Coordinators ("RC"), Protection and Telecom Operations ("PTO"), Operation & Maintenance ("O&M"), Distribution Controls & Integration ("DC&I"), Critical Network Infrastructure
- Installation: RC, PTO, O&M, Overhead Crews, DC&I, Distribution Control Center ("DCC")
- Commissioning: PTO, O&M, Overhead Crews, DC&I, DCC

Now that the Company is in the third year of VVO deployments, many of the departments are familiar with the technology. For those who are new to VVO, there is continued support through online and face-to-face trainings. The Grid Modernization Execution team is responsible to administer the training and track the progress of the work through commissioning and then Measurement & Verification ("M&V") testing.

Progress over the term includes:

2019

- 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.

2020

- Continued streamlining the overall process, from design to commissioning, reducing end-to-end duration of the deployment.
- Continued refining documentation for all key processes with updated check sheets, job aids, and material tracking.
- Procurement of equipment (capacitors, regulators, feeder monitors and advanced controls) to ensure a continuous flow of devices from supplier to meet project demands.
- Continued to gain many insights into the process that allowed the Company to make improvements in design, construction, installation, commissioning, and safety.

- Maintained the central repository for VVO device locations and their associated control settings.
- Two substations (Stoughton and East Methuen, total of 12 feeders) completed all construction and commissioning.
- One substation (Maplewood, eight feeders) completed all construction and approximately 90% of commissioning.
- Stoughton Site Acceptance Test was successfully completed. This involved running the system for 24 hours a day for two weeks.
- Stoughton VVO system was put into service on July 24th.
- M&V test protocol was initiated on the Stoughton Substation on December 1st.
- Developed formal training modules for Engineering, Design and Construction.

2021

- Establishing an equipment supply pipeline (capacitors, regulators, feeder monitors and advanced controls) to ensure a continuous flow of devices from supplier to meet project demands.
- Completed all device installations for 21 feeders.
- Completed substation VVO upgrades for three substations (East Methuen, Maplewood and East Bridgewater)
- Completed Site Acceptance Testing and initiated M&V testing on these three substations. Completed M&V testing on Stoughton.

In 2021, the Company extended progress on the implementation of VVO technology. As in past years, the Company continued to gather feeder level highlights and lessons learned that were applied to subsequent work.

Based on the success of completing construction and commissioning on one full feeder at a time, the concept was pushed upstream all the way to design. Grid Modernization Execution coordinated with the Design team which started to focus work at the feeder level. Subsequently, when a feeder was construction ready, the Resource Coordinators would order all the equipment for that feeder. This then streamlined PTO, DC&I and EMS processes to office-commission all equipment and allow for the O/H crew to focus on the construction work and complete the process.

The Company deployed and commissioned twenty-two advanced capacitors in Central and Western Massachusetts to mitigate potential impacts of DG. In a modernized grid, advanced devices can be used for dual purposes. The sensing and control in these devices allows the Company to deploy the capacitors and optimize voltages based on system conditions whether to mitigate transmission substation voltage issue during certain periods of the year, provide volt-var optimization during certain periods of the year, and do both during other periods of the year. Advanced controllers are affiliated with each smart capacitor install. The advanced controllers are necessary for hosting the capacitor settings and communication equipment for each capacitor device. These controllers are installed with smart capacitors that are installed, including the ASO capacitors and the capacitors installed as part of VVO implementation. The smart capacitors have the ability to switch on or off according to local power and/or voltage conditions. The software used for the VVO scheme uses data from these advanced controllers as well as other smart devices to implement the algorithm that enables a further optimized system end-to-end. As a result of these emerging DER issues and opportunities in Central and Western Massachusetts, the Company deployed voltage optimization investments to progress grid modernization objectives.

	Commissioned					
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	3
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	Western - 09	702	Chestnut Hill	Athol	2	4
BSW	Western - 09	507	Wilbraham	Wilbraham	1	1
BSW	Western - 09	508	E Longmeadow 1	E Longmeadow	1	1
BSW	Western - 09	503	Palmer	Palmer	2	2
BSW	Western - 09	139	N Hampden	Hampden	1	1
BSW	Western - 09	523	Thorndike	Ware	1	1
					17	**22**

2. Lessons Learned/Challenges and Successes

Lessons Learned:

- 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.

- Recognized the need for a centralized repository for VVO device locations and their associated control settings; as a result, developed a SharePoint site to collect and share this information.
- During the field commissioning process, found there were portions of the process that could be completed during the internal building phase.
- Developed device office commissioning which led to more efficient field commissioning efforts. Documented this new process as a best practice reference.
- Identified safe working practices for new equipment and trained all work crews.
- 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.
- Recognized the importance of having a program manager facilitating the progress of the work as it transitioned from phase to phase and department to department.
- Found that, while each substation and its equipment are unique, there are still many similarities in the process. Passing Lessons Learned from one substation to the next has helped to refine and shorten the process.
- Recognized that the process of preparing and office commissioning equipment for VVO is new to the operating personnel, built a process and created manual tracking sheets to track the progress.
- Learned that roles and responsibilities vary slightly between operating areas, often based on labor agreements. Adjusted the process to adhere to these agreements and share best practices to improve efficiency.
- Building on lessons learned last year from the manual equipment tracking spreadsheets, the Company was able to develop status points within the workflow process system to identify progress of equipment through the office commissioning process. This provided visibility and clarity to the operations team regarding construction readiness.
- The Company evaluated the efficiency results from the first M&V reports and identified a way to improve VVO effectiveness, i.e., to add VVO technology to substations with phase regulating devices as opposed Load Tap Changers ("LTC"). The phase regulators will allow for more granular control of the system which will result in higher efficiency gains.
- The Company recognized that each LTC upgrade is unique and requires specific equipment modifications to facilitate VVO operation. The Company built into the process key technical operational requirements that are discussed at the early design meetings and initial substation walk-through.

Challenges:

- The VVO technology was new to the workforce in Massachusetts. Trained the workforce to familiarize them with the operation of VVO and the uniqueness of the equipment used for the program.

- Identified a challenge in our material planning and management processes that limited visibility of material availability and location. This challenge is being addressed for future programs.
- The biggest challenge for 2020 was learning how to work with the limitations and restrictions of COVID. This lengthened the installation process for all equipment.
- The VVO technology was new to the workforce in Massachusetts. Requiring the need to train the workforce to familiarize them with the operation of VVO and the uniqueness of the equipment used for the program.
- The impacts of COVID-19 and absenteeism continued to be a challenge for the operations team, leading to short-staffing issues, which impacted the project schedules.
- After a VVO system is commissioned and is in the M&V stage, it needs to continuously run for several months to provide the best data for the analysis. However, some field devices get damaged or become inoperative and require repair in order to keep the VVO system running optimally. The Company's process for dealing with repairs was not streamlined and led to some devices being offline for several weeks. This situation was identified and the Company created a team to evaluate a new process of "2nd Day Support" for all new Grid Modernization equipment.

Successes:

- Able to build a new streamlined process for Office Commissioning that led to streamlined workflow and reductions in downstream errors.
- Able to demonstrate that a program like VVO can be completed from end to end within one calendar year (from design to in-service).
- Successfully built a Material Planning process to forecast and order long lead-time equipment, eliminating any material shortages.
- Crews sharing lessons learned lead to improving the efficiency of installation resulting in decreased crew work time and reduced truck deployment per install.
- Implemented the new work-flow system changes to track equipment through the office commissioning process.
- Trained all operations personnel at four area work locations including hands-on demonstrations.
- Developed and published an on-demand training module: "Introduction to VVO" for any Company personnel interested in learning about the technology and its benefits.
- Several of the VVO implementations overlap with FLISR. Information from the FLISR field devices is integrated with the VVO scheme so the technologies can operate jointly on the same feeder. By design, when the FLISR scheme activates, VVO detects this operation and automatically disables until the feeder is returned back to its normal state.

This occurred on the Stoughton feeders on November 4, 2021 and successfully worked as designed

3. Description of benefits realized as the result of implementation

Tab 5.d Spending – 2021 Report in the attached Department Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 22-28.
The Company continued construction and commissioning of field devices and substations throughout 2021. An additional three substations and 21 feeders were completed and commissioned 2021. M&V testing protocol began in March for East Methuen, September for East Bridgewater and December for Maplewood substations. By the end of 2021, the Company had a total of four substations and 27 feeders equipped with the VVO technology.

The first VVO M&V results for the Stoughton station were captured over three seasons throughout the year, Winter, Spring and Summer. The peak benefits were realized during the winter months December 1, 2020, through March 31, 2021. Overall, the average outcome across the Stoughton substation was a 0.58 percent observed power decrease and a 0.91 percent voltage decrease. Although these results exhibited savings, it was lower than the expected range of 2% to 4% energy efficiency. The Company has been engaging with the VVO software vendor, Guidehouse and internal planning and engineering teams to review the results and drivers behind the lower performance. This will help inform opportunities that can be applied to future VVO scheme design and implementation.

4. Description of capability improvement by capability/status category

To date, the VVO technology has been deployed on 4 Substations/27 Feeders which were commissioned and enabled. As they have been deployed the VVO system optimized energy usage based on system needs and loads. The formal measurement and verification protocol for substations were initiated upon completed final site acceptance testing for each of the locations. Additionally, even before they were fully operational, all equipment deployed for VVO (once installed and field commissioned) provided the ancillary benefits of providing visibility and data to the distribution control center operators.

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 embedded in energy consumption by customers
- Improved management of the distribution system which will assist in the integration of DERs

- Improved fault location
- Improve feeder voltage performance
- Improved system awareness into the daily operations and planning processes

5. Key Milestones

Substation	Engineering Complete	Construction Complete	In Service	Start M&V
East Methuen	Jul-2019	Jan-2021	Feb-2021	Mar-2021
Maplewood	Jul-2019	Dec-2021	Dec-2021	Dec-2021
Stoughton	Jul-2019	Jul-2020	Jul-2020	Dec-2020
East Dracut	Sep-2020	May-2022	May-2022	Jun-2022
West Salem	Sep-2020	Apr-2022	May-2022	Jun-2022
East Bridgewater	Sep-2020	Jul-2021	Jul-2021	Jul-2021
Melrose	Mar-2022	Oct-2022	Nov-2022	Dec-2022
Westboro	Mar-2022	Oct-2022	Nov-2022	Dec-2022
Easton	Mar-2022	Oct-2022	Nov-2022	Dec-2022

Milestone Complete

A. (2) Advanced Distribution Automation

ADA is a 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. Previously National Grid had communications capabilities to some of the reclosers on the distribution system but did not coordinate their operation during faults beyond their local protective control. The ADA scheme replaces manual tie points between adjacent feeders, to provide for downstream restoration. It also integrates enhanced telecommunications and additional control on existing protective switches, and potentially adds switch locations as necessary to optimize system reliability.

1. Performance on Implementation/Deployment

The FLISR/ADA program deployment for Massachusetts was initiated in the second quarter of 2019 with the selection of 12 substations and 16 feeders to be upgraded with the new technology.

In the third quarter of 2019, the engineering team scoped out an additional 22 substations and 27 feeders. Furthermore, in the beginning of 2020, the engineering team scoped out 29 feeder monitors and one capacitor bank to maximize FLISR automation. The feeder monitors were added to ensure load checks were accurate so that the FLISR automation can safely tie into another feeder when the opportunity arises. The capacitor bank was included to address some voltage concerns on a FLISR feeder. Throughout 2021, the Company made continual progress toward the goal of deploying FLISR/ADA onto 43 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 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 second round of deployment added slightly more complexities with more reclosers per scheme and one scheme with DERs.

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

- Completed sanctioning for all fiscal years during the term.
- Documentation of all key processes with updated check sheets and job aids.
- Engineering analysis of candidate feeders through evaluation of poor-performing circuits and various metrics.
- Streamlined the overall process, from planning and designing to commissioning and implementation to reduce end-to-end duration of deployment.
- Evaluated and optimized the overall deployment process mentioned in the bullet above through the life cycle of the program.
- Developed, updated and improved end-to-end FLISR deployment process map.
- 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, pandemic shortages, and to meet project schedules.
- Completed design for all field work and issued work requests for the 43 feeders.
- Initiated design for planned schemes for the upcoming fiscal year 2023.
- Successfully identified the need for a QA/QC process for advanced control device settings for FLISR and initiated implementation of said process.
- Planned scheduling and construction of various FLISR work requests.
- Documented several FLISR events and recorded the associated performance metrics.
- Collected lessons learned throughout the process to make improvements in planning, engineering, design, procurement, scheduling and implementation.

- Implementation of 14 FLISR schemes that went live and are currently active. This is in addition to the two FLISR schemes that went live in 2020, for a total of 16 live FLISR schemes at the end of 2021.

Below is a list of the 16 schemes that have been completed. The Stoughton (913W69 & 916W43) scheme and the East Boxford (33L1) and Woodchuck Hill (56L3) scheme were completed in 2020, and the remaining 14 schemes were completed in 2021.

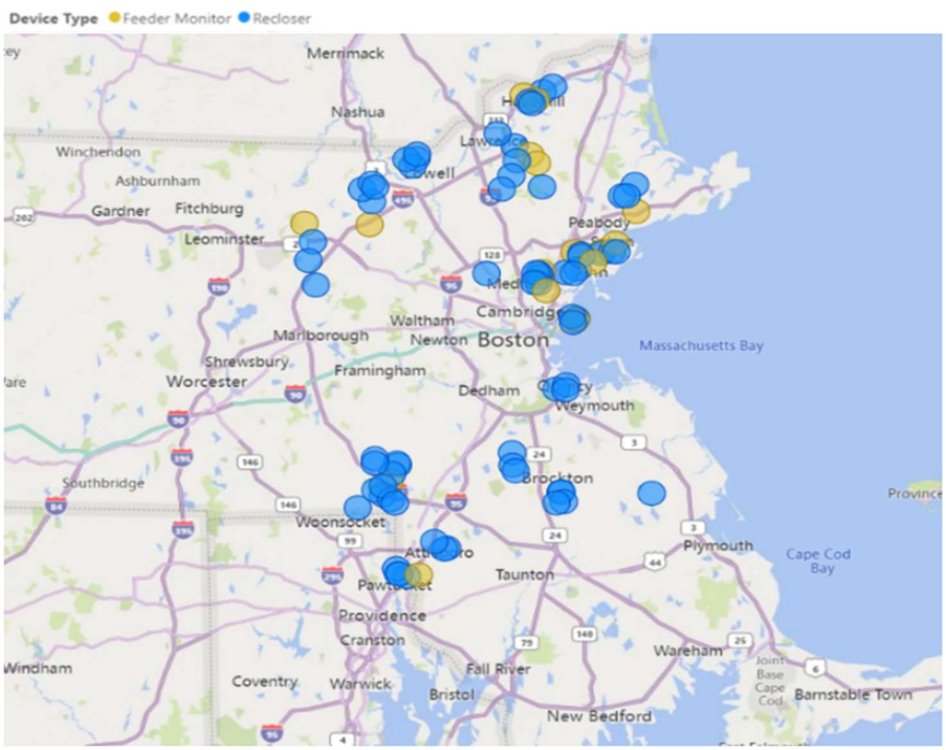
Completed Schemes as of December 31st, 2021

District	Substations with (Feeder)	Commission Date	Reclosers	Feeder Monitors
BSN	Hoover St (21L1) & North Dracut (78L1)	3/24/2021	4	1
BSN	Westford (57L2 & 57L3)	3/18/2021	5	2
BSN	East Boxford (33L1) & Woodchuck Hill (56L3)	12/31/2020	3	0
BSW	Fitch Rd (216W6) & Ayer (201W2)	12/9/2021	4	2
BSS	Stoughton (913W69 & 916W43)	10/26/2020	4	0
BSS	West Quincy (3W3) & Field St (1W5)	7/22/2021	4	0
BSS	Read St (9L3 & 9L6)	10/7/2021	4	1
BSS	Union St (348W7 & 348W8)	7/12/2021	5	1
BSS	Read St (9L1) & Charley Pond (8L3)	10/7/2021	3	1
BSN	Woodchuck Hill (56L1) & East Tewksbury (59L6)	2/21/2021	5	2
BSN	Maplewood (16W6) & Melrose (25W4)	12/16/2021	5	2 (1 Cap)
BSN	Saugus (23W2) & West Salem (29W1)	3/31/2021	4	2
BSN	North Beverly (18L2) & East Beverly (51L3)	12/16/2021	3	1
BSN	Winthrop (22W5) & Metcalf Sq (96W1)	8/13/2021	4	2

BSS	Belmont (98W19) & East Bridgewater (797W19)	2/5/2021	2	0
BSS	Dupont (91W49) & East Bridgewater (797W19)	3/12/2021	3	1
			62	18

The completed devices that are part of the 16 schemes listed in the table above are plotted on the following map to show relative locations. Reclosers are shown in blue and feeder monitors are shown in yellow.

Installed Devices as of December 31st, 2021



The projected plan was to have 22 total schemes commissioned by the end of 2021. Sixteen were commissioned, and the remaining six will be completed in 2022. The six schemes are listed below:

Remaining Schemes Planned for Commission in 2022

District	Substations with (Feeder)	Reclosers	Feeder Monitors
BSN	West Methuen (63L1) & East Dracut (75L3)	3	1
BSN	Water St (31L2) & North Haverhill (48L2)	4	2
BSS	Franklin (341W1) & Beaver (344W5)	6	2
BSN	Quinn (24W1 & 24W2)	3	2
BSN	East Methuen (74L4) & Ward Hill (43L4)	3	2
BSN	Dale St (55L1) & North Andover (71L1)	5	2
		24	11

In addition to the 22 schemes mentioned above, there are nine schemes currently planned for calendar year 2022. Summing up to 41 reclosers and 12 feeder monitors, these nine schemes are in design and are planned to be completed in 2022.

Throughout the year of 2021, the commissioning of these feeders did face a variety of challenges. Although the process was established and streamlined from previous and active implementation of other FLISR schemes, progress was delayed due to the ongoing COVID-19 pandemic, scheduling conflicts, crew resourcing issues, and various weather events. Once the reclosers for each FLISR scheme were installed, the Control Center operators were able to work with the engineering teams to seamlessly test and confirm functionality of the FLISR technology. With the challenges previously mentioned, the success of 14 FLISR schemes also came with several lessons learned.

2. Lessons Learned/Challenges and Successes

The Company enabled 31 feeders representing 16 FLISR/ADA schemes from program start to the end of calendar year 2021 and has collected lessons learned throughout the process.

The key lessons from the FLISR program implementation 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 what exists in the current utility workforce in order to deliver and manage this new, enhanced equipment and new technologies.
- Using a hybrid grid communications strategy where a combination of 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 need for a centralized settings repository for all FLISR advanced grid device settings that will also serve as a quality checkpoint for the Company's Protection and Engineering teams.
- The significance of communication among stakeholders regarding candidate feeder selection to avoid problematic areas of implementation. Suggestions and open discussion help highlight the roadblocks that are not otherwise known.
- The need to ensure that zone logic and automation capabilities are programmable within the data concentrator (Orion) so that the 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. This is particularly important during a pandemic where the supply chain is facing several challenges between staffing, transportation, materials and manufacturing.
- Anticipating unknowns and adapting the plans and response to minimize impacts to schedules and milestones. This occurred in the form of the need for alternative settings for reclosers that act as the tie points between feeders; this need was identified and implemented ensuring that it will be accounted for in future rollouts.
- The importance of staying engaged and aware of other recloser program inventory needs and construction schedules. Communication and transparency are the main drivers to avoiding any inventory and construction bottlenecks.
- Proactive process mapping and anticipation of testing requirements allowed for commissioning to be executed seamlessly for the FLISR schemes that have gone live.
- The significance of utilizing DG facilities that are already live to incorporate into FLISR/ADA schemes to avoid scheduling delays of DERs that are in the process of interconnection. This is the barrier that is delaying the implementation of the Company's first DER-integrated FLISR scheme.
- The need to formulate and execute an end-of-year game plan to implement FLISR schemes amongst other programs and priorities.
- There were a few challenges in the design phase where incorrect funding and scopes with missing field devices were found. This was mitigated by meeting with the Design team to

clarify the program needs and hosting a bi-weekly call while working through the incomplete work requests. This is a continued effort throughout the design process and for future implementation of upcoming FLISR plans.

- The challenge and importance of keeping an updated list of crew resources throughout the jurisdiction that have been impacted by the ongoing COVID-19 pandemic.
- Building on the success of 2020 for the implementation of two FLISR schemes on four feeders and collecting the lessons learned from that process. With this knowledge, the project team was able to proactively prepare for future commissioning and kick off a strong start to 2021.

The Company faced a variety of challenges on the path to commissioning and implementing FLISR in 2021. The Company had planned for 22 FLISR schemes to go live by the end of 2021 but was only able to achieve 16 FLISR schemes to go live by the end of the year. During 2021, efforts to commission 43 feeders on 22 FLISR schemes were delayed due to the COVID-19 pandemic where resource impacts affected absences of crews in various work locations. The Company also encountered materials lead time and vendor procurement delays which impacted the ability to schedule work throughout the calendar year. Additionally, there were delays for building the new settings template file to incorporate alternative settings that are required when a tie recloser is closed in upon FLISR automation. Internal prioritization of materials management and incorporation of materials demand increases are also part of 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.

Aside from resource impacts from the COVID-19 pandemic and the frequency of weather events that delayed construction schedules, another hurdle was figuring out the best method of work request completion. Work requests are created for each individual recloser or feeder monitor of a FLISR scheme and progression levels can vary for each one. This means if there was a three recloser FLISR scheme, essentially there were three separate work requests and three timelines. Each work request faces its own individual challenges when it comes to construction as one work request may have environmental issues, and another could have permitting or digging involved. These challenges were mitigated through a manual tracking process for each work request and forecasting when a FLISR scheme was able to go live in accordance with its individual installations. Additional efforts to streamline this challenge included grouping installations into FLISR scheme bundles and keeping communication between scheduling and operations consistent to ensure schemes were able to go live as efficiently as possible.

A lesson learned from the work request challenge was figuring out that there was a need for additional engagement with the resource coordination and resource planning teams. A bi-weekly meeting was set in place to help track and progress priority work requests so that FLISR schemes can go live more effectively. Building on the previous foundation throughout the year of 2021, these meetings continue to be a major success in the establishment of a synergistic process for future FLISR implementation going into 2022.

3. Description of benefits realized as the result of implementation

The benefits of having live FLISR schemes is that there were four FLISR events in calendar year 2021. All four events restored 35% or more customers under the one-minute Massachusetts threshold for frequency, and an additional three operations in early 2022 produced similar results. All four events reduced the event customer minutes of interruption ("CMI") by 40% or more, and an additional three operations in early 2022 produced similar results. Two of the successful events occurred during the major event Winter Storm Wanda. The first was East Boxford (33L1) and Woodchuck Hill (56L3) which operated on February 2, 2021 during a storm event where FLISR automation was able to restore roughly 400 customers. The second event was West Salem (29W1) and Saugus (23W2) which operated on October 27, 2021 during another significant weather event where FLISR was able to restore over 1,500 customers. During the same storm on October 27, 2021 the third event took place at Field St (1W5) and West Quincy (3W3) where FLISR was able to restore just over 2,000 customers. Lastly, the fourth occurrence was on Stoughton (913W69 & 913W43) which operated on November 4, 2021 and was able to restore over 2,800 customers. Additionally, the Stoughton feeders were able to successfully disable VVO to show interoperability between the grid technologies of FLISR and VVO. See the table below for additional reliability information from these four events.

Event Date	Feeder	Total # of Customers Impacted from Fault	Customers Restored	Method of Restoration	Time to Restore	Major Event? Y/N
2/2/2021	East Boxford (33L1)	993	396	FLISR	16 seconds	N
			597	Field Restore	2hr, 17min	
10/27/2021	West Salem (29W1)	2954	1494	FLISR	16 seconds	Y
			1460	Field Restore	2hr, 21min	
10/27/2021	Field St (1W5)	3045	1097	FLISR	15 seconds	Y
			1948	Field Restore	7hr, 44min	
11/4/2021	Stoughton (913W69)	3593	2821	FLISR	22 seconds	N

			376	Field Restore	45 min	
			396	Field Restore	2hr, 20min	

The live FLISR schemes continue to show success in 2022. Between January and March of 2022, there have been three additional FLISR events, which have positively impacted over three thousand customers.

4. Description of capability improvement by capability/status category

Aside from the four FLISR events described above, the benefits of FLISR to include:

- Optimizing system performance – National Grid anticipates approximately a 25% reduction in main line CMI on the individual feeders targeted for the ADA deployment. This projected reduction is based on historical analysis of actual past performance in the 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 DERs as a tool to operate the system. ADA capability improvement will enhance reliability and resiliency.

5. Key Milestones

The Company has installed and commissioned 14 FLISR schemes from January to December 2021, totaling 16 FLISR schemes from the program start to the end of calendar year 2021. This translates to 25 substations and 31 feeders to go-live for the program by the end of 2021. The Company is forecasting completion of the remaining 6 carry-over schemes from the originally planned total of 22 schemes for calendar year 2022. Additionally, key accomplishments from the Company plans were as follows:

- The Company designed 14 FLISR/ADA Schemes on 27 feeders.
- The Company procured all the field devices necessary for the 14 FLISR/ADA schemes, including but not limited to reclosers, feeder monitors, and radios.
- The Company procured server equipment for the Northborough Control Center which allowed for the testing of the ADA schemes and to verify the proposed logic was functional.
- 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.
- The Company anticipated and prepared for final commissioning that allowed for 14 ADA schemes to go-live.
- The Company scoped out 9 additional FLISR/ADA schemes on 16 feeders.
- The Company compiled a list of lessons learned to optimize future implementation.

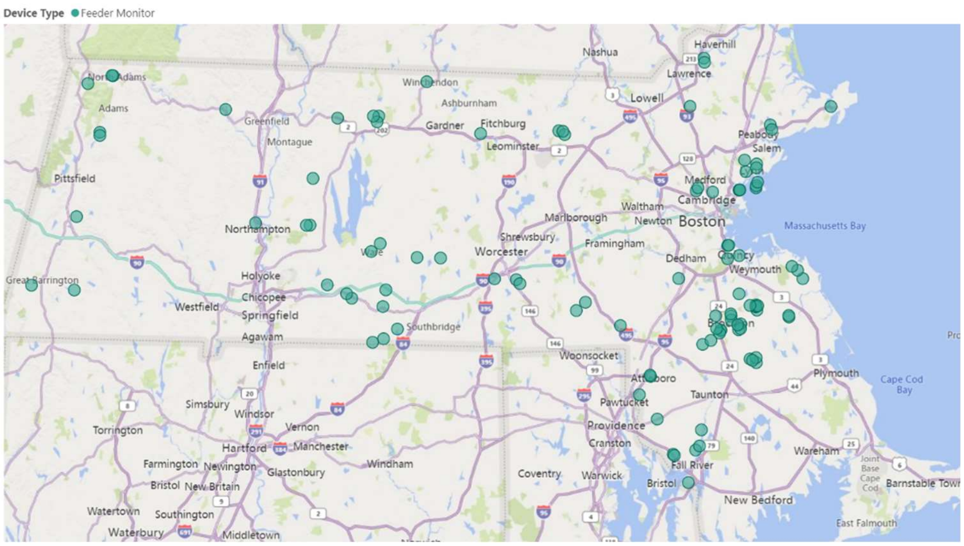
Future deployment goals for 2022 are an additional 9 FLISR/ADA schemes, which total to 41 reclosers and 12 feeder monitors on 16 feeders (though that is subject to change until the scope is finalized). Tab 5.d. Spending – 2021 Report in the attached Department Annual Report Template provides the deviation in the implementation and spending. Refer to columns D-L, rows 17-21.

A. (3) Monitoring/Control

The feeder monitors program installs interval power monitoring devices on feeders where the Company does not currently have this information. Feeder monitors create visibility for the control centers and the information collected is 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 fills this awareness gap and assists in more efficient operation and maintenance, planning and storm recovery, in furtherance of the Department's objectives for grid modernization.

Installed M&C Devices



1. Performance on implementation/deployment

The Company has reviewed its 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 is deploying head-end mainline feeder monitors which are used to capture real-time voltage, current and power. The operations control center uses this information, as well as 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 four-year grid modernization plan term.

Following is a list of work completed from 2018 to 2021:

- 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 by preliminary engineering. Design takes these locations and design each project in accordance with National Grid standards.
- Both Telecom Operations ("Telecom Ops") and Distribution Control and Integration completed cellular strength testing for all locations to determine if more advanced designing was needed or the 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 Modernization Execution and Engineering created an office commissioning step to ensure that all communication equipment was operational before field deployment.
- Continuously improved overhead operational work habits through tracked lessons learned as well as bulletin updates to ensure current standards were being met.
- Determined new locations for installs at midline of the feeder and on feeders highly impacted by COVID-19 load shifting and added them to the scope of work.
- Organized and carried out biweekly meetings with all the project critical players in order to continuously align the goals of the project.
- Created strong lasting communication with material vendors in order to create a reliable material pipeline.
- Improved and streamlined the Feeder Monitoring Process map to ensure that critical tasks were not being held up and all responsibilities and expectations were clearly understood by each department.
- Field construction and commissioning of 155 field devices was completed.

Monitoring and Control had continued success in 2021 with the commissioning of 84 feeder monitors bringing the 4-year total to 155 in December of 2021. Feeder-level successes were realized through compounding prior historical data and data collected from the feeder monitor to make informed engineering decisions. These decisions included substation LTC rebalancing to better serve customers to avoid projected overloads through load balancing instead of reconductoring. In addition to these engineering benefits, feeder monitors have been used to ensure that feeder integrity is not compromised during major storm events. In the event of a widespread outage, feeder monitors are checked to ensure that the feeder is still in service and has not been knocked out at the substation. This benefits outage response emergency crews by narrowing down potential outage areas and ensuring that crews are being used in the most efficient and impactful way.

2. Lessons Learned/Challenges and Successes

After going through 155 installs there were several lessons learned some of which built upon lessons learned from prior years, including:

- Assembly of the mounting brackets for the control box should be attached to the box in-house.
- The commissioning process needed to be updated and shared with the control room in order to allow for a smooth commissioning process between the DCC and the Overhead Crews.
- Sensor cables should be phase-labeled and the phase diagram of the feeder should be given ahead of time to Overhead in order to increase the efficiency of device installation.

- Trained Overhead Crews to attach sensors to crossarms on the ground and then use two trucks to lift them if the crossarm was being replaced as a work method for increasing efficiency.
- 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 installations
- Material was being shipped with other non-Grid Modernization assets causing confusion on material location and the loss of material and time to track down missing material. To rectify this, material was labeled and placed on individual pallets and receiving engineers were notified of all material arrival dates.
- LineWatch Sensor training was updated to include technical troubleshooting techniques to avoid issues in the implementation of technology in the field.
- Meetings with vendors ahead of material issues and constant communication about expectations lead to more visibility on supply problems as well as expectation setting for the supply chain of the project.

Challenges:

- Due to the COVID-19 pandemic, both overhead and telecom operational management faced resourcing difficulty due to quarantine and recovery time of employees infected by the virus. A work plan prioritization process was established which altered initial plans and scheduling.
- Due to the global supply chain shortage of semiconductors, material ship times increased significantly causing delays in the construction timeline.
- In the beginning of the construction phase, Lindsey sensor material shortage due to vendor miscommunication on the vendors side led to delays in material ordering and the construction timeline.
- Due to an arc flash incident involving a Lindsey Sensor install, the company experienced a work stoppage period specific to Lindsey sensor installs. This work stoppage period was elevated once an incident analysis was completed to ensure future worker safety before reactivation of the delivery construction timeline.

Successes:

- Successfully increased the intake of feeder data across the state through installing 155 Feeder Monitor devices. This data gathered has already led to important grid modernization improvements through their detection of load imbalance.
- Successfully completed training with Overhead Crews and Telecom Ops for new Feeder Monitor equipment that is expected to be used next year in the field.
- Contributed to the National Grid GIS map by adding 155 data points and providing historic feeder data to our Distribution Planning and Asset Management team which has actively aided in their planning of new equipment installs and initiatives.

- During storm outages feeder data from installed sensors has aided in determining if feeders were impacted, replacing the need for crews to check head of line feeder integrity, and allowing more targeted dispatch of repair crews and damage assessment employees.

3. Description of benefits realized as the result of implementation

Building upon the initial five feeder monitors installed in 2019, 66 feeder monitors were installed in calendar year 2020, and in calendar year 2021, 84 additional feeder monitor devices were completed and commissioned. The main contributing factor to the discrepancy from the goal of 170 completed was the continued COVID-19 pandemic. The pandemic presented multiple challenges that caused delays in the project timeline. The most significant was the reduction in work hours due to COVID-19 Guidelines and prioritization of essential maintenance to enable the regional shift to work from home for customers. A lesser but still important to note impact is also quarantine time of crews exposed to the COVID-19 virus and work location shutdowns that came from localized incidence of infection in smaller work locations. These collectively caused the reduction in work leading to the 2021 feeder monitoring goal being missed. In addition to COVID-19 concerns, one other factor that delayed installs was that certain locations required two sets of sensors due to issues determined during overhead precheck such as bifurcation and location-based construction constraints, including but not limited to pole replacements, pole relocation, and environmental considerations. All of these caused delays to the construction schedule.

The deployment of the 155 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 internal PI Historian software.

The benefits include:

- Visibility of real-time demand.
- During the winter storm event on October 17, 2019, the feeder monitors saved time in the technical assessment of the 910W2 feeder in Hanover, Massachusetts. During the emergency outage 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.
- On the Swansea 11W83 feeder, feeder monitors informed a load-balancing solution to a projected overload. Prior to the installation of the feeder monitors, only single-phase loading information was available so there was not visibility of the load imbalance issue. The initial resolution for the projected overload would have included reconductoring a significant section, and through the additional data and visibility the projected overload pursued a lower cost approach of load balancing.

- In the East Bradford area of the 65L3 feeder, East Bradford Ski was reporting electrical voltage issues. By leveraging the data of the feeder monitors at the station, it was able to be deduced that low LTC settings was the root cause. Original settings showed the voltage at the substation would be allowed to go as low as 96% of nominal with it going no higher than 101%. After using the monitor as a reference and consulting operations able to adjust the LTC raising the nominal up to around 99% during its low dips and as high as 103%.

ACTUALS COMMISSIONED 2019

District	Town	Device	QTY
Southeast	Abington	Lindsey	2
Southeast	Pembroke	Lindsey	1
Southeast	Hanover	Lindsey	1
Southeast	Bridgewater	Lindsey	1
TOTAL			5

ACTUALS COMMISSIONED 2020

District	Town	Device	QTY
Central	Auburn	Lindsey	1
Central	Millbury	Lindsey	2
TOTAL			3

District	Town	Device	QTY
Merrimack Valley	Andover	Lindsey	3
Merrimack Valley	Haverhill	Lindsey	2
TOTAL			5

District	Town	Device	QTY
North Shore	Beverly	Lindsey	2
North Shore	Gloucester	Lindsey	1
TOTAL			3

District	Town	Device	QTY
South Shore	Dighton	Lindsey	1
South Shore	Somerset	Lindsey	1
South Shore	Swansea	Lindsey	3

TOTAL			5

District	Town	Device	QTY
Southeast	Abington	Lindsey	4
Southeast	Bridgewater	Lindsey	2
Southeast	Brockton	Lindsey	18
Southeast	Cohasset	Lindsey	1
Southeast	Easton	Lindsey	3
Southeast	Holbrook	Lindsey	2
Southeast	Quincy	Lindsey	3
Southeast	Rockland	Lindsey	1
Southeast	Stoughton	Lindsey	4
TOTAL			38

District	Town	Device	QTY
Western	Belchertown	Lindsey	1
Western	Buckland	Lindsey	1
Western	Northampton	Lindsey	1
Western	Palmer	Lindsey	4
Western	Ware	Lindsey	2
Western	Warren	Lindsey	3
TOTAL			12

ACTUALS COMMISSIONED 2021

District	Town	Device	QTY
Central	Auburn	Lindsey	1
Central	Ayer	Lindsey	3
Central	Millbury	QNA	3
Central	North Brookfield	Lindsey	1
Central	Spencer	Lindsey	1
Central	Westminster	Lindsey	2
TOTAL			11

District	Town	Device	QTY
North Shore	Beverly	Lindsey	1
North Shore	Lynn	Lindsey	4
North Shore	Medford	Lindsey	4
North Shore	Nahant	Lindsey	2
North Shore	Nahant	QNA	1
North Shore	Revere	Lindsey	3
TOTAL			15

District	Town	Device	QTY
South Shore	Attleboro	Lindsey	6
South Shore	Dighton	Lindsey	1
South Shore	Fall River	Lindsey	1
South Shore	Franklin	Lindsey	1
South Shore	Mendon	Lindsey	1
South Shore	Milford	Lindsey	1
South Shore	Rehoboth	Lindsey	1
South Shore	Somerset	Lindsey	1
TOTAL			13

District	Town	Device	QTY
Southeast	Abington	QNA	1
Southeast	Bridgewater	Lindsey	3
Southeast	Brockton	Lindsey	3
Southeast	Hanover	Lindsey	1
Southeast	Quincy	Lindsey	5
Southeast	Quincy	QNA	1
Southeast	Scituate	Lindsey	5
Southeast	Stoughton	Lindsey	1
TOTAL			20

District	Town	Device	QTY
Western	Adams	QNA	1
Western	Athol	Lindsey	2

Western	Athol	QNA	1
Western	Belchertown	Lindsey	1
Western	Brimfield	Lindsey	1
Western	Cheshire	Lindsey	1
Western	Cheshire	QNA	1
Western	Great Barrington	Lindsey	1
Western	Holland	Lindsey	1
Western	Holland	QNA	1
Western	Lenox	Lindsey	2
Western	New Marlboro	Lindsey	1
Western	North Adams	Lindsey	1
Western	North Adams	QNA	1
Western	Palmer	Lindsey	3
Western	Shutesbury	Lindsey	1
Western	Wales	QNA	1
Western	Ware	Lindsey	1
Western	Wendell	Lindsey	2
Western	Williamstown	Lindsey	1
TOTAL			25

TOTAL COMMISSIONED 2019-2021

TOTAL			155

4. Description of capability improvement by capability/status category

With the 155 completed installs visibility on the loading of lines has increased to the Distribution Control Center and Distribution Planning and Engineering teams. This has improved the visibility and data available for understanding line loading and voltage issues and serves as an early alert to outages to enable faster identification and improved response times.

5. Key milestones.

Milestones	Install Numbers and target dates					
FM installs	1-9	10- 25	25-55	55-90	90-130	130-160

Complete Project Sanction	Apr-19	Apr-19	Jul-19	Jul-20	Jul-20	Jul-20
Engineering Completed	Jul-19	Oct-19	Mar-20	Aug-20	Nov-20	Jan-21
Design Completed	Jul-19	Oct-19	Mar-20	Aug-20	Nov-20	Jan-21
Construction Completed	Feb-20	Jun-20	Nov-20	Feb-20	Apr-20	Dec-21
In-service date	Feb-20	Jun-20	Nov-20	Feb-20	Apr-20	Dec-21

*Note: Plan based on total number of feeder monitors installed. While there are 180 locations, each location can have multiple feeder monitor sets installed.

A. (4) Communications and Information/Operational Technologies (IT/OT)

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

- Comprehensive Integration Services (CIS) - The integration services to enable the exchange of information between systems, services and devices.
- Enterprise Analytics - The big data analytics capabilities to allow for the analysis of the data gathered from grid modernization investments combined with existing and third-party data sources, providing valuable output reflecting current state as well as predictive and prescriptive outcomes.
- Communications and Networking - A set of communication services that transfer information with the correct prioritization and quality of service to the appropriate destination.
- Integrated Network Operations Center (INOC) - To actively monitor, manage and maintain the integrated set of telecommunications network services and infrastructure, and to provide a single point of contact for support and operations through a cross-functional set of people, processes and technologies.
- Grid Control Devices and Applications - The deployment of distribution solutions supporting the monitoring, management and control of the distribution grid.
- Enterprise Architecture - An enterprise architecture approach mitigates stranded costs typically experienced in "one-off" siloed solutions, and minimizes the expense,

configuration and management complexity that individual built-to-purpose applications often experience.

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 network elements such as the wireless field area network (FAN) that were critical investments for progressing grid modernization. During 2019, the Company commissioned wireless coverage and channel reuse studies for both the 700 MHz and 900 MHz spectrums frequency bands and evaluated other available spectrums and technologies associated with different spectrum options. Results provided initial baseline costs for the acquisition of 700 MHZ and 900 MHz spectrum and the ability to model implementation costs for based on a site count of base stations across the service territory. 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.

To leverage some of the investment and work already completed within the utility industry related to network communications, the Company has also established working groups with other joint utilities both nationwide and regionally to share lessons learned and collaborate on the various types of network technology that has been evaluated and 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 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. At the beginning of calendar year 2020, the Company revisited the priorities and needs for the Communications and IT/OT investment area. Specifically, it decided to defer significant investments in private fiber expansion for the initial plan period and focus on further developing the field area network (“FAN”) and wide area network (“WAN") solutions. Furthermore, development and implementation of the Telecommunications Operations Management System (“TOMS”) software tool solutions will deliver greater capabilities and cost efficiencies over the longer term as well as provide Network the Operations groups increased capability to manage, maintain and troubleshoot the growing communications network. This software will enable the planning, design, deployment, and maintenance of telecom networks. In 2020, the Company issued a Request for Proposal (“RFP”) and demonstrations on the execution

of software test scripts were completed. Following final evaluations, a vendor was selected. Tool setup and data unloads started in 2021 and are currently taking place.
The Company also prioritized the IT investments for the Comprehensive Integration Services and an Enterprise Analytics platforms to deliver efficiencies and benefits from the inflight efforts.

Comprehensive Integration Services

CIS is the middleware that is required to move data between systems, automate and manage business processes, transfer files between entities and enable real-time and batch integration of data. National Grid is developing these capabilities to enable real time integration, automation and orchestration of business processes enterprise-wide for existing legacy systems, and implementation of new systems building on process and systems efficiencies, needed for grid modernization. The main components of the Modern Grid Platform include the Advanced Distribution Management System (ADMS), Geographical Information System (GIS for the network model), Telecommunications, Planning and Engineering Capabilities, Volt Var Optimization (VVO), Feeder Monitoring and Advanced Distribution Automation (ADA).

The Company has established an enterprise standard for CIS. CIS includes an enterprise service bus which delivers a standards-based integration where performance, scalability and reliability are critical requirements.

1. Performance on Implementation and Deployment

In January 2020, a Solution Vision Document ("SVD") was conditionally approved by the Company's Architecture Review Board ("ARB"). The SVD recommended the setup of a MuleSoft-based Integration Platform over which the various Grid Modernization integrations would be delivered. On June 3, 2020 a Conceptual Solution Architecture was approved by the same ARB. The Company progressed a partial sanction for requirements and design work on July 23, 2020. The Company progressed full sanction to progress the development and implementation phase for the project on December 30, 2020. The Company has completed the setup of the core platform which is the foundation on which the integrations to enable grid modernization will be delivered. Multiple environments to support development, test and production have been provisioned. The platform components include: Enterprise Service Repository, Business Activity Monitor, Complex Event Processor, Connectors/Adapters, Cloud Integration Platform, and Application Program Interface ("API") Management. In addition, deployment of software and associated licenses were fully deployed in November 2021, which included the setup of the core platform which is the foundation on which the integrations to enable grid modernization was delivered. Multiple environments to support development, test and production have been provisioned, and integration work in support of the GIS Phase 1 and the ADMS Phase 1 projects are complete.

2. Lessons Learned, Challenges and Successes

During the requirement phase, a lesson learned is to plan to consider a detailed discussion of MuleSoft platform features pertaining to project requirements at the very early stage. This will enable platform-side activities to start early to provide required customized features as per project requirements, resulting in reducing last minute dependency.

Another lesson learned is to verify the right and unique set of encryption key references in each of the environments before onboarding the interface. This practice will save significant time and effort during the go-live phase and avoid additional changes for correcting the encryption key references.

3. Description of Benefits Realized as the Result of Implementation

Apart from delivering a core enabling infrastructure and services across the Grid Modernization landscape, the CIS project provided the following benefits towards the ongoing integrated, secure, scalable operation of Grid Modernization business capabilities:

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

4. Description of Capability Improvement by Capability/Status Category

- Improved user productivity by leveraging and extending services appropriately utilizing correct protocol and integration standards (e.g. lightweight APIs for Mobile and RICH Web consumption).
- Provided end-to-end traceability and audit capability and alerting for operational efficiency.

Enterprise Analytics

Changes to the modern electric grid and requirements to manage two-way power flows, ever increasing DER interconnection and emerging needs to share granular, timely data requires better, faster and cost-effective ways to meet customer and stakeholder expectations. National Grid's current methods of data management are not sufficient for managing the volume and diversity of data necessary for these grid modernization needs. Managing ever-increasing levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions and customer demand. As the Company deploys more sensors, grid connected devices and other grid modernization investments we will see enormous growth of incoming data. To take full advantage of insights that can be derived from this information, we need to evolve from a semi-centralized data approach to a fully centralized data management capability where there is one overall distribution data model. Additionally, these investments will better enable advanced technologies like artificial intelligence or advanced analytics that require that our data is more fit for purpose, readily available and timely.

Enterprise Analytics architecture is a storage repository that holds a vast amount of raw data in its native format until it is needed. Data can be pulled directly from the data sources into the storage area. All data in raw form will be available in one place. Once all data is brought into the storage repository, users can access relevant data for analysis and derive new insights through analytics.

This investment delivers foundational data management capabilities by enabling enhanced data governance across key datasets. The focus has been on implementing the necessary data management tools and processes to ingest data, catalog data, and assess and improve data quality from a central data platform. In line with company standards, the centralized platform will be used to measure/monitor critical data elements and their accuracy, integrity, completeness, consistency, etc., to sustainably support continuous data improvement. Setting this foundation is critical to establishing the longer term, envisioned data management platform that is required for moving forward. Coordinated with business process changes, this investment is focused on starting that journey - deploying data catalog, modelling and data quality toolsets to enable grid modernization business use cases.

1. Performance on Implementation and Deployment

In 2019, a data management planning and strategy effort was undertaken to identify a framework and roadmap for implementing a Grid Modernization data management platform and associated tools to satisfy the Company's data needs of today and the data needs for the future. From this exercise, several data management use cases were identified based on the Grid Modernization Business Capability Model. In 2020, a current state assessment for the data management use cases was performed, after which the use cases were prioritized, and project scope was aligned with the objectives of maturing data management and governance practices.

The Company is working towards the creation of a standardized and comprehensive data model and the setting up of tools for data quality and data cataloging. The Company completed the analysis of business data capabilities, high-level use cases, and a preliminary inventory of data sources. Initial assumptions about the product and architecture for the Enterprise Data Platform have been re-validated and the Company has finalized the selection of software products for data catalog, data quality, data store, and visualization/reporting. There was a partial sanction submitted and approved on September 9, 2020, for requirements and design, as well as for partial build and deployment. It also includes software, hardware, and hosting costs related to new data quality, data catalog and data modeling toolsets. The project received full sanction in 2021 to complete development and implementation using the new toolsets, in combination with development and implementation of a staging data platform. The Company completed deployment of software and associated licenses for Enterprise Analytics Phase 1 focused on deploying a centralized electric distribution data repository to support grid modernization in June 2021.

2. Lessons Learned, Challenges and Successes

Lessons learned include:

- Data governance and role-based access needs to be defined before the data is made available across the organization
- Some data needed reclassification. As a part of Enterprise Analytics Phase 1, data was classified into sensitive and non-sensitive data. Data is now being classified into its highest level of security: External Use, Internal Use, Confidential, and Strictly Confidential.
- Alignment and understanding of the cybersecurity requirements and how third-party products can support the requirements will minimize the need for alternate or short-term solutions when discovered during the testing phases.

3. Description of Benefits Realized as the Result of Implementation

The initial phase 1 deployment delivered the central data platform for storage, integration, and access to distribution network and asset data in support of foundational data management capabilities by enabling enhanced data governance across key datasets. The phase 1 implemented the necessary data management tools and processes to ingest data, catalog data, and assess and improve data quality from a central data platform, to establish a mechanism to measure/monitor critical data elements and their accuracy, integrity, completeness, consistency, etc., to sustainably support continuous data improvement.

While the initial phase 1 work was completed in June 2021, Enterprise Analytics aims to achieve the following in the next phase:

- Enhance operations and engineering decisions via network visibility of increasingly granular field-edge data points
- Support risk-based asset management decision making through improved data accuracy, confidence, and analysis
- Support better predictive analytics and forecasting models for outage management, load flows, load forecasting and emerging distribution network functions

All the above are drivers for this project and its emphasis on data. The value of data management to support new Grid Mod technologies will only accelerate as more data becomes available with the delivery of Grid Mod projects. The data methods and learnings from this initial Grid Mod Data Management project are expected to inform future needs and considerations.

4. Description of Capability Improvement by Capability/Status Category

- Delivered a centralized data repository with automated data pipelines ready for product teams to use.

Platform has been approved by security and therefore can store data classified as – Internal use only, confidential or strictly confidential.

Communications and Networking

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 network plan are:

- Provide a reliable, cost-effective two-way communications capability to end devices including grid automation controls, field sensors and substations.
- Ensure the network meets all technical requirements for the devices and systems deployed. These requirements include availability, latency, bandwidth, security and other performance considerations.
- Provide Network Operations with 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 practical.

The telecommunications network is comprised of two main elements: field area network (FAN) and wide area network (WAN). The FAN provides "last mile" communications to the end devices where field-installed grid controls are the endpoints on this network layer. The 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. At the beginning of 2020, the Company revisited the priorities and needs for the Communications and IT/OT investment area. Specifically, it decided to defer significant investments in private fiber expansion for the initial plan period and focus on further developing the FAN and WAN solutions.

1. Performance on Implementation and Deployment

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 network elements such as the wireless field area network (FAN) that were critical for modernization. During 2019, the Company commissioned wireless coverage and channel reuse studies for both the 700 MHz and 900 MHz frequency bands and evaluated other available spectrum and technologies associated with different spectrum options. Results provided initial baseline costs for the acquisition of 700 MHZ and 900 MHz spectrum and the ability to model implementation costs based on a site count of base stations across the service territory. The Company has also reviewed wireless 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.

To leverage some of the investment and work already completed within the utility industry related to network communications, the Company has established working groups with other joint utilities both nationwide and regionally to share lessons learned and collaborate on the various types of network technology that has been evaluated and implemented.

Development and implementation of the Telecommunications Operations Management System (TOMS) network tool started in 2019 with the Company issuing a Request for Proposal (RFP) for software that will enable the planning, design, deployment, and maintenance of telecom networks. The tool will deliver greater capabilities and cost efficiencies over the longer term as well as provide network operations groups increased capability to manage, maintain and troubleshoot the growing communications network. TOMS provides single point of failure diagnostics and calculations, with an end-to-end network view of circuit connections. It also provides work order management capabilities to facilitate maintenance, troubleshooting and reserving resources, as well as automating circuit design inclusive of mapping and fault analysis.

Vendor demonstrations on the execution of test scripts were completed and final evaluations and vendor selection were completed in 2020. A contract and scope of work was signed and the design phase for the software was initiated with a two-phase approach. Phase 1, to provide minimum viable product (MVP) capabilities, was completed in December 2021 which will support efforts to progress field surveys for base lining and enhancing the data in 2022. The MVP objectives that were achieved included the implementation of the core software modules on the Company infrastructure for multiple environments for development, testing, quality assurance, and production. With the software environments available, telecommunications equipment data from various source systems was collated, cleansed, and then loaded for subsequent testing to ensure data was ingested and presented correctly within the application.

TOMS application administration was completed to establish initial user groups and associated permissions for the requisite user community. Existing fiber data, such as Optical Ground Wire (OPGW) and All-Dielectric Self-Supporting (ADSS), was also migrated from the Company's GIS platform to enable fiber network mapping capabilities. As a proof of concept, a single ring for the data multiplexer (DMX) Synchronous Optical Network (SONET) WAN was modeled, including the circuit layers between sites, and the remaining rings will be completed in 2022 during the next phase. A Document Management System was also implemented which provides users the ability to store and open files within the application through connectivity to a dedicated SharePoint site. Once the MVP development work was completed, User Acceptance Testing (UAT) was successfully executed to validate that business requirements were met. Official MPV go-live for the production environment and service transition to the IT support organization was achieved in December 2021. Phase 2, which will deliver the balance of the planned product functionality through interfaces and integrations to back-office applications, is projected to complete in 2022.

In 2019, the Company performed a current state assessment of the WAN and determined that the existing DMX SONET equipment 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 core network architecture linking critical 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 consultancy in December 2019 to deliver a market research report to identify vendors with available technologies, product maturity, and utility experience. Based upon these efforts, the Company issued an RFP in March 2020 for the replacement of the DMX SONET backbone equipment. This new network equipment will enable the expansion of the WAN and future-proof the backhaul for multiple technologies in support of grid modernization. Based upon the vendor responses to the RFP, scoring was completed, and three vendors were down-selected to participate in testing of each solution against a comprehensive set of test cases. An initial round of testing was performed in December 2020 and additional testing completed in February 2021. Upon completion of the testing and an evaluation of the results, a final vendor selection was made in March 2021 and formal negotiations and contracting started. The contract with the vendor will be formally executed in early 2022.

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.

2. Lessons Learned, Challenges and Successes

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, rationalizing services and building towards the minimum viable product.

Successes to date include:

- Successfully deployed initial release of the TOMS application into Production in Dec 17, 2021 as part of MVP release.
- 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.
- In support of the DMX SONET replacement project, the Company down-selected to three vendors that offer either Multi-protocol Label Switching - Transport Profile ("MPLS-TP") or IP Multi-protocol Label Switching ("IP/MPLS") solutions. These solutions underwent operational and security testing in a third-party vendor's lab to evaluate the ability to meet the requirements and capabilities to support the future growth of the WAN.
- The Company selected an MPLS-TP vendor for the WAN and negotiations and contracting have begun.
- 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 and other

operational business needs such as replacement of analog or Digital Signal 0 (DS0) circuits used for tele-protection or substation RTUs.

- The initial 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.

3. Description of Benefits Realized as the Result of Implementation

The Company has continued to install cellular communications for the devices commissioned to date. The Company had not planned for implementation and deployment of the WAN and FAN in the first plan period.

The current network planning, capacity and management business processes are highly manual, supported by various number of tools such as spreadsheets, drawings, and stand-alone databases. The TOMS MVP phase delivers a mature application to realize the following benefits:

- Improving data quality with a single, integrated application for all network information to the circuit level
- Automating circuit design, including mapping and fault analysis
- Automating data transfer with integration across other corporate systems
- Generating and tracking work orders for network changes
- Remotely configure and deploy logical connections across the telecom network
- Remotely manage and push software updates to equipment
- Detect, locate, and isolate communications and connectivity failures in the telecom network

4. Description of Capability Improvement by Capability/Status Category

The path to deliver the greatest customer benefits through WAN and FAN investments will occur over the long term in gradually expanding privatization of these two network elements which will provide increased control, availability, and security of the communications network. However, in the near term, the Company recognized that the use of public cellular will provide some customer benefits until final WAN/FAN solutions are delivered.

The TOMS MVP release was successfully deployed in December 2021 to allow the business to start field survey activities. Data migration was completed for equipment license data, Cascade, GIS, and Circuit Data (Eastern and Western Fiber Rings). Over 700 unique equipment models have been created and loaded into the TOMS application. Consistent naming conventions are used for sites, equipment and circuit definitions.

Integrated Network Operations Center

The INOC ensures proper operation and performance of the communication infrastructure supporting multiple GMP business services over a hybrid network. The INOC is a central location from which network administrators manage, control, troubleshoot and monitor one or more networks. The overall function is to maintain optimal network performance across a variety of platforms, mediums, networks, network segments, devices and communications channels. The INOC monitors the health and behavior of all data and communications of the grid using an Operation Support System ("OSS") and has the capabilities to provide a first level of incident response. Monitoring, provisioning and configuring are accomplished by computer-based tools that create alarms when anomalous activity, performance issues or system failures are detected. National Grid's grid modernization investments will provide many new business services and the INOC is key to their efficient operation. It will eliminate the risks of a point-to-point system in an electric grid with a greatly increased number of systems and end points.

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

1. Performance on Implementation and Deployment

In October of 2020, the Company initiated a review and assessment effort for the INOC investment area. The Company issued an RFP on October 29, 2020 seeking consulting services to support the development of a framework and approach for progressing an INOC effort including the following: an assessment of the people, process and technology aspects, a service level basis for Service-Level Agreements and Operation-Level Agreements and an overall investment and business case structure. The successful vendor was selected in December 2020 and the effort was mobilized in early 2021. The final report and initial recommendations were delivered in March 2021. In October 2021, the Ideation and Validation phase was initiated to progress the framework and assessment outcomes and identify and document existing and proposed state of network operation management functions for Grid Modernization investments. The project will identify and prioritize core foundational capabilities for an INOC platform and develop a roadmap with clear vision for INOC rollout.

2. Lessons Learned, Challenges and Successes

As part of the Grid Modernization journey, a telecommunications strategy has been developed to help shape the foundational communications network to support all existing and future communications requirements. The INOC will allow the Company the capability to provide real time supervision and control of all telecommunications equipment infrastructure supporting future grid modernization initiatives.

The objective of the INOC is to bring together a centralized location where the network operation staff will provide 24X7 supervision, monitoring, and management, and be able to take corrective actions for all telecommunications network equipment including wireless devices, radios, servers, switches, databases, firewalls, devices and related external services. It provides a "single pane of glass" top-down view for support and operations through a cross-functional set of people, processes, and technologies.

The Company is in the process of planning discussions with other utilities that have deployed similar integrated NOC's to document their lessons learned, challenges, and recommendations. In August of 2021, a visit was made to tour Portland General Electric's state-of-the-art Integrated Operations Center (IOC) in Tualatin, OR to learn more about their facility which was in the final stages of construction.

3. Description of Benefits Realized as the Result of Implementation

While we are in the early phases of this project, a key benefit of the INOC is that it provides a centralized location for the network operations staff to provide 24X7 real-time monitoring, management and corrective actions. Network administrators use Network Management Software to maintain the quality of services of all end-to-end connections in a network per individual service level agreements. Mature applications are available in the telecommunications industry, which, when integrated with network elements, planning/design systems, cybersecurity systems, and business processes, significantly improve the efficiency and effectiveness of managing the network and cybersecurity functions.

These capabilities collectively will provide the following benefits:

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

- By creating a successful combined support model with clearly defined tools and processes, new solutions should be easier to integrate into the existing models leading to quicker time to market and deployment.

4. Description of Capability Improvement by Capability/Status Category

As part of the INOC project the following high-level capabilities will be enabled as a centralized platform to monitor and take corrective actions:

1. Fault Management
2. Configuration Management
3. Administration Management
4. Performance Management
5. Security Management
6. System Integration

Key Milestones

Milestone	Target Date	Completed Date
FAN 700MHz Implementation Costing	October 2019	October 2019
WAN Market Research Report	December 2019	December 2019
WAN equipment vendor RFP	March 2020	March 2020
Construction standards for WAN expansion	June 2020	March 2021
Substation fiber termination using developed WAN construction standards	December 2020	
TOMS vendor selection, procurement, and project kickoff	December 2020	December 2020
WAN equipment vendor testing	August 2020	February 2021
WAN vendor selection	September 2020	March 2021
Field surveys for WAN expansion	December 2020	
FAN equipment vendor testing	July 2021	
FAN preliminary network design	August 2021	
TOMS MVP Release	October 2021	December 2021
Enterprise Analytics Phase 1	June 2021	June 2021
CIS Phase 1	June 2021	November 2021
INOC Assessment	April 2021	April 2021

A. (5) ADMS/DSCADA

Prior to ADMS implementation, National Grid utilized an EMS, a SCADA system, and an Outage Management System ("OMS"). EMS/SCADA is used to monitor remote devices in real time and capture data in a centralized location to be used 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 electric vehicles or other nonconforming loads, DERs, 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 centralizing data, enhancing efficiencies and digitalizing operational processes. The system allows for greater visibility and situational awareness. 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 leveraging a bi-directional load flow, with the capability to simulate future states and configurations of the distribution grid, taking into consideration interconnected DER. 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 DERs. The ADMS is an intelligent network platform supporting a step change in the operational integration of DERs and is a foundational investment for transition to Distribution System Operator.

This project implements 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.

A project team composed of Company and contractor resources have been convened for Massachusetts. Personnel with skills in engineering, operations, data management, and IS are working collectively to analyze data on the Company's entire distribution system consisting of over 1,100 distribution circuits encompassing more than 6,445 circuit miles. This team adopted a multifaceted approach that makes use of analytical models and techniques, Company and commercial data sources, and, as required, field observation and monitoring. By leveraging these techniques, the team has developed new GIS capabilities to expand and improve the data necessary to maintain network models for advanced applications.

The project is progressing as planned and has remained aligned with milestones for ADMS and other grid modernization projects. As of December 31, 2021, data has been enhanced for 11,284 miles on 418 Massachusetts feeders via the Data Enhancement Project. Additional quality control processes have been implemented to enhance data accuracy.

Project deliverables include the following:

System Enhancements:
- Configure and program GIS to accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics has been completed.
- Configure and program GIS to facilitate capture of greater data and modeling granularity for underground distribution networks.

- Configure and program GIS to facilitate more granularity for low-voltage secondary distribution networks.
- Develop substation modeling capability to support operations and planning processes has been completed.
- Develop additional tools and improve existing toolsets used to manage data quality and processes in GIS has been completed.

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

Process Review and Improvement:
- The partial post capability was completed and implemented to improve data accuracy and reduce design-to-post cycle time.

Dependency on building out DSCADA substation control capabilities:

This investment will facilitate the virtual (dual porting) and physical separation of RTUs 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. It allows for expansion of remote monitoring and control, while supporting continued stability for transmission SCADA, and taking into consideration lessons learned from past control center-centric projects. The DSCADA component of ADMS is a prerequisite for advanced application control related functions such as VVO, or any FLISR functions involving substation monitoring or control.

ADMS/DSCADA Implementation Approach:

The ADMS project is being implemented using a phased approach that will put different modules and functionality into service over the period of 2021 through 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, as well as the ability to gather feedback and expand in areas where the most value is added. By leveraging process analysis to target change management and training activities and an iterative progression for functionality 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 has put distribution management system applications in service for the electric distribution control rooms to use in a monitor and inform capacity. The first phase of ADMS was implemented in 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 2023 through early 2024. When complete this common centralized ADMS platform will allow for the continued integration of new technologies, expansion of solutions, and operational integration of DERs. The phased rollout will include the following steps:

<u>Phase 1 - Completed and in service in plan year 2021</u>

I. Build out governance frameworks, team structure, and key performance indicators for project
II. Requirements and capability specification, enterprise architecture review
III. Future state process design considering Phase 1 functions
IV. Change management functional impact assessment, stakeholder communications
V. Data element identification and GIS data improvements, extract improvements
VI. ADMS network and infrastructure specification, procure and build
VII. System build and data population, validate and tune application functionality
VIII. Acceptance testing of baseline monitor and inform applications
IX. Training of end users
X. Production implementation of monitor and inform functionality via baseline DMS applications on a predetermined number of feeders

Phase 2

I. Design, test, and enable the OMS components/modules of the ADMS allowing for the retirement of the existing OMS

II. Implement AMI interfaces, and mobility solutions interfaces with OMS module to ensure alignment and benefits realization from these programs

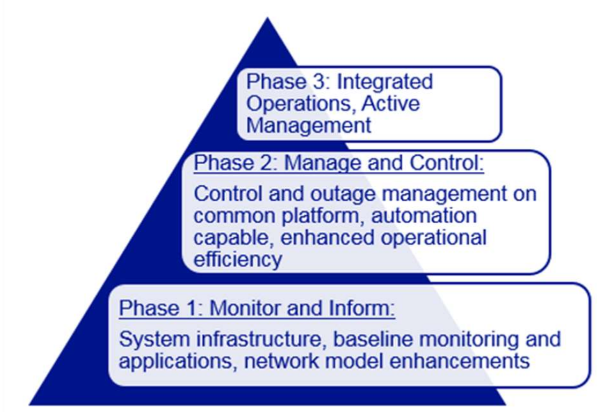
III. Enable DSCADA integrated with OMS and applications to provide common platform visualization and management for the distribution network

IV. Expansion of applications including advanced functionality capable of automation and control

V. Implementation of a DSCADA leveraging data from substations via RTU work

Phase 3:

Extend automation and move towards active network management. Interface with remote metered and grid edge devices, and advanced DER control, via interface with a distributed energy resources management system ("DERMS").



1. Performance on implementation/deployment

During 2020, the Company completed an analysis and scoping effort for the development of the ADMS project. As part of this effort, business capabilities and system requirements were captured. ADMS Phase 1 system design activities are complete, major vendor contracts are in place and hardware and software was procured. A thorough analysis of operational procedures affected by the rollout of ADMS phase 1 as well as a review of change impacts and training requirements were completed. This ensured the solution fits as designed into the Company's operations, is properly adopted, and delivers expected benefits. System infrastructure build out and phase 1 Factory Acceptance Testing ("FAT") were completed. GIS and engineering data were incorporated into the ADMS load flow solution. User training, business acceptance and phase 1 system go live completed in 2021.

During 2021, the Company implemented Phase 1 of the project, going live with Phase 1 in May 2021, and started efforts for Phase 2. This is in accordance with the Company's 5-year plan. 2021 work completed includes change management work, operator / end user training, various testing phases, cutover, post go-live hyper care, ADMS ready feeder work, and the start of Phase 2 work. As part of Phase 2 work in 2021, the Company started to progress the OMS upgrade into ADMS by: reviewing requirements, working with the ADMS vendor to prepare test cases for future FAT and Site Acceptance Testing ("SAT") work, and completing a review of OMS business process to ensure an understanding of impact of change to critical business processes.

Areas of work details:

Engineering, Infrastructure and Data:
In 2020 the team procured hardware, software, system design and build out. Logical technical model and physical technical design models were completed. The building and configuration of a dedicated network for the ADMS system for local control center secure access between consoles and servers was completed, then performance tested. The ADMS system environments were built out following internal standards to allow for proper backup and progression of software throughout environments.

Solution testing, data preparation and readiness work was completed throughout plan year 2020. In the fall of 2020 FAT was carried out on the ADMS Phase 1 system. As part of FAT, the team architected the data migration in conjunction with internal data owners of several key ADMS data elements (source, line, and transformer impedance characteristics, capacitor settings, and equipment limits) and worked towards identifying areas of data shortfalls. The team completed more than 500 system test procedures, designed to test ADMS system functions (GUI, GIS interfaces, DMS applications). The team established frameworks for monitoring and managing increasing DER penetration, including incorporating DG assets into the operational network model. Feeder readiness was conducted on a predetermined set of Phase 1 go-live feeders. These feeders were progressed through a series of data and engineering analysis until they were deemed test-ready. In 2021, SAT, UAT, and performance testing were all completed on the new systems. Additional test feeders and test data was gathered for SAT. Additional feeders were incrementally added to the ADMS throughout the year post go-live to expand usability.

As part of the overall corporate data strategy, the data team began to coordinate a more rigid data process with Distribution Engineering. Identification of the ADMS critical data points during FAT helped in the initial development of a business data consolidation plan. Future execution will allow the ADMS team to implement a strong data governance approach with detailed data quality monitoring in the next phase of the project.

GIS improvements and data hardening are in progress. Field surveys to acquire digital photographs of the Massachusetts electric distribution system were completed. 83.5% of the available Massachusetts electric distribution poles accessible from public right of way were acquired, resulting in over 605,000 digital photos. The data team continues to review and update data. The identified changes to baseline GIS were completed in September 2021 allowing for new asset types, new equipment, expanded attributes and characteristics. The data team established a continuous monitoring process to ensure that the cleansed data remains at the appropriate level of quality and completeness.

Future incremental expansion of phase 1 will involve continued expansion of feeder coverage and operational integration of DER, improved fault location analysis, and integration with the new Snowflake database for non-GIS electric system data.

Process Analysis and Design:
A thorough analysis of business processes was carried out to ensure that all ADMS capabilities were correctly integrated into current control room workflows and procedures. An as-is analysis was completed and to-be processes including ADMS functions were built. The work involved project team support and input from various business groups who perform the functions affected by ADMS. A Change Impact Analysis ("CIA") was conducted on the new ADMS processes to identify and analyze the upcoming changes and rank their impact to stakeholders. This alignment will ensure that the ADMS program is integrated with the as-is business functions and identified areas of improvements with future state business functions. This work will also ensure that the implementation of ADMS into the control room will be seamless and effective for the users and deliver expected benefits. In 2021 a review of outage management-related business processes was completed in preparation for the phase 2 OMS upgrade as part of ADMS.

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

During 2020, the team sat down with various key stakeholders from different groups to listen to their current understanding of the ADMS program, their concerns and their questions, in order to get a pulse of the current sentiments. The CMO developed a holistic approach to promoting stakeholders' engagement throughout the program, in supporting the business to reduce go-live risks through the business readiness approach and in driving adoption and proficiency of the ADMS system by the stakeholders to maximize benefit realization through training.

The CMO is broken down into the following core workstreams:
- Overall change management planning;
- Stakeholder communication and engagement;
- Business readiness; and
- Training.

Given the length of the ADMS program and its multi-phase approach, the team created a unified, stakeholder-centric, change management strategy and plan, which can be leveraged in subsequent phases to both create program continuity and to reduce re-work. In addition to the strategy, other planning phase documents were developed to build a strong foundation and best practices such as establishing a governance model. A change network strategy was also developed to create efficiency with the rest of the business and allow for an effective two-way communication with the stakeholders.

A Change Impact Analysis (CIA) was conducted on the new ADMS processes to identify and analyze the upcoming changes and rank their impact to stakeholders, in conjunction with the business process work. This analysis helps create understanding about what changes each stakeholder group can expect from the ADMS, supporting the creation of future communication material, answering stakeholders' questions, and managing expectations. The CMO leveraged existing business process design workshops to optimize stakeholders' bandwidth and more efficiently identify the process changes. The CIA is foundational to developing initial stakeholders' communication and engagement, and determining training needs. As such, the CMO developed a comprehensive communication plan and an engagement plan which can be leveraged and scaled for future phases. The plans took into consideration communication preferences from different stakeholder groups to allow tailoring based on these preferences. The CMO went on to execute against these plans by creating multiple communication collaterals (for example, videos, one-pagers, emails, etc.) which have received very positive feedback. Additionally, a SharePoint and ADMS email have been set up to allow for question and feedback submissions. The CMO is regularly gathering feedback through these channels and through surveys to ensure the stakeholders are getting the right level of information and feel involved in the project to create buy-in. All work noted here ensures that the system is understood by the end user and functionality is leveraged properly to add value as intended overall.

The majority of ADMS end users in the phase 1 implementation are located in the control center. Given the 24/7 operations nature of their work, and the criticality of their role in keeping the lights on, a training strategy accommodating their shifts and potential storm duty roles was developed. Additionally, the unprecedented COVID-19 crisis pushed the CMO to determine a training

approach that adapted to accommodate remote training needs to ensure the safety of the stakeholders. Ongoing analysis and assessments helped build a comprehensive training curriculum and training materials which are centered around the new ADMS functionalities and processes to help users understand how their roles are changing.
The training was designed to promote the best learning experience and results by leveraging multiple training approaches such as instructor-led trainings, in-class exercises, roadshows, etc. A successful and positive training experience is an important measurement in driving the adoption of the ADMS by its users to realize the system's benefits. The training was delivered in Spring of 2021 to the control rooms successfully. Feedback from attendees was positive and indicated that they felt prepared for go-live.

From May 2021 – December 2021 the Change Team refreshed the change management strategy and supporting plans leveraged for phase 1 to support phase 2.

In the late spring and early summer of 2021, the team sat down with various key stakeholders from different groups to listen to their current understanding of the program, their concerns and their questions, to get a pulse of the current sentiments. This body of work was the beginning of stakeholder engagement and outputs formulated the basis for lessons learned from phase 1 and considerations for phase 2 in the areas of communications, training, business readiness and stakeholder engagement.

Following the stakeholder analysis work, a change impact analysis was completed specifically for Phase 2, following same approach as was applied for phase 1 CIA.

The stakeholder analysis and change impact analysis together informed the overall Phase 2 change management strategy and plans for communications, engagement, and training.

Governance, controls and process:

The program continues to use the existing governance structure that was implemented in 2020. Creation of the project governance structure set the ADMS program up for success by establishing how decisions would be made and who needed to be involved in the decision-making process. Guidelines and procedures were created to assist in managing the project. This framework assisted in resolving obstacles and issues that can block strategic success. The ADMS governance structure has created a clear communication plan that is well-defined, updated regularly and leveraged by the project team and stakeholders. This clarity and consistency in decision-making and communication has assisted the ADMS project in maintaining schedule in a critical time period with COVID-19. Through the established and defined roles and responsibilities of the project team members, stakeholder groups and executive steering committee, the project has been able to overcome many challenges. Changing standard in-person testing to remote system testing was a key event that required multiple decisions. Setting up remote connectivity so that critical areas of the program could be performed remotely, was a key accomplishment. Having a strong governance structure in place has assisted in keeping all cross-functional teams aligned and focused on the right areas of the project, thus keeping everyone and the project moving in the same direction.

The addition of several key performance indicators allowed the team to gain valuable insight into several areas of the project and provide transparency for all stakeholders. A Baseline Execution Index is used to monitor the execution pace of the project. Other metrics used to monitor the project include Financial Management, Risks and Issue Management, and Resource Management. These metrics provide valuable information that assists the team in the decision-making process.

ADMS team members work closely with associated programs to ensure alignment continues and has support from the internal assurance team to help identify both strong areas of the project as well as areas to improve before there are any adverse impacts. Through close monitoring, the ADMS program has remained on schedule during both 2020 and 2021 and the project was implemented in accordance with the original schedule.

2. Lessons Learned/Challenges and Successes

- Having a strong governance structure in place has assisted in keeping all cross-functional teams aligned and focused on the right areas of the project and supported effective decision-making, thus keeping everyone and the project moving in the same direction especially during this year considering challenges related to the COVID-19 pandemic.
- A proactive Company stance on safety as well as new IT access tools allowed for the transition to work from home during the pandemic. Although remote connection to systems and logistics surrounding remote work does create some challenges from an efficiency standpoint there are some very real successes. The ADMS team was able to think creatively and come up with multiple options to support continued progress on the project implementation, much done remotely, during the COVID-19 pandemic. One example of a success was the ability to shift what was designed to be on-site testing to a fully remote test phase. This took changes to IT infrastructure, detailed task development between the Company and the ADMS vendor, and flexibility in the team's tasks. Testing was successfully completed on time even given all these challenges.
- There were some challenges surrounding team expansion due to constraints caused by COVID-19. Although the team overcame these challenges the ramp-up of resources dedicated to the ADMS project was slower than expected
- Significant additions and expansion to base network model data to support ADMS advanced applications was required beyond what was previously used for distribution operations. The

definition of interdependent programs and systems, such as GIS, has been noted, and 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 the Company's 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.
- A thorough analysis of operational processes was required to understand how the technical solution fits into operations. This helps ensure an understanding of where changes are needed, where training should be focused and overall supports better adoption and long-term benefits realization.
- 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.
- The ADMS change team successfully prepared Massachusetts DCC stakeholders for phase 1 go-live, via effective stakeholder engagement, communications, business readiness check-ins and training. The change team consistently engaged DCC leadership to gather input and feedback via monthly directors' calls and business readiness check-ins. Additionally, the team served as a conduit and partner for other workstreams to reach DCC leadership to gather input and sign-offs on other critical project activities such as UAT. The change team relied heavily on virtual mechanisms to engage with the control room. In July of 2021, the project team gained significant value from an in-person visit to speak with the operators about their experience using ADMS in the eight weeks since go-live.
- Moving forward for additional phases of ADMS, would like to work with DCC leadership to establish change champions who can work with on a more regular basis to represent their peers and work more closely with the CM team in addition to DCC directors.
- Similar to 2020, COVID-19 challenges were encountered during 2021. These included resource constraints with both internal and external staff due to absentee rates, supply chain constraints and long lead times on critical hardware components, and restrictions on access to critical areas for things like training and user upskilling supported by the project team due to limited access to control rooms because of heightened COVID-19 restrictions. The team looked for opportunities to overcome these challenges. Internal and external staff picked up extra job duties when staffing was short to keep the project on schedule. The team worked closely with suppliers to get critical components ordered earlier than anticipated to reduce supply chain strain, and training was completed virtually rather than in person.

- Testing for phase 1 took place during peak COVID-19 in 2021. Testing that is typically done onsite and in person was limited due to COVID-19 restrictions. The team was able to pivot and offer remote login to perform all testing activities that typically would take place onsite.

3. Description of benefits realized as the result of implementation

The Company has installed supporting infrastructure such as system hardware and networks that are the backbone of the ADMS. This work was carried out as planned. Project governance, reporting and key performance indicators were developed to ensure the project continues to develop on track to yield benefits. For the term, ADMS did not have any planned benefits identified during phase 1, therefore there is no variance at this time.

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 had second quarter of calendar year 2021 as the projected implementation date. The Company targeted a roll out of the initial phase of capabilities of ADMS for June 2021. The company went live May 14, 2021 in Massachusetts and Rhode Island with the phase 1 system. The tentative timeline for phase 2 Massachusetts implementation is late 2023 to early 2024.

4. Description of capability improvement by capability/status category

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. This effort is on track, 130 feeders were completed at go-live and 276 ADMS-ready feeders were completed as of December 31, 2021.
- ADMS will create a platform to enable utilization of exponential growth of remote monitoring, control and distribution automation. This is part of the phase 3: Integrated Operations and Active Management future work.
- Enable system operations to maintain or improve reliability under the growing system complexities associated with the integration of DERs. In 2022, the team will be revising the operational processes to take advantage of the ADMS foundation and increase the utilization of solar generation output during abnormal conditions such as outage restoration. In a similar effort in New York, the Company’s New York affiliate is integrating the fault location analysis into ADMS via importing real-time fault current data from National Grid-owned field devices which will improve pinpointing potential outage locations in certain cases. This effort will also be implemented in Massachusetts.
- Centralizes data, visualization, monitoring, control and automation capabilities maximizing operational process efficiencies. For all non-GIS electric system data, spearheading a data digitalization effort starting in 2022 which will interface with the ADMS database. This will

allow key information such as protection settings and relay pickup to be imported into ADMS similar to the successful transfer data from the internal GIS.

- Enables operators to simulate future state of the grid in abnormal configurations to optimize grid asset utilization. The team plans to add 150-200 more ADMS-ready feeders this calendar year. As expected, priority will be feeders with high DG penetration.
- Enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.
- Refresh and upgrade outage management capabilities into the common system ADMS targeted for late 2023 to early 2024.

5. Key Milestones

Milestone	Target Date	Completion Date
Complete R&D Project Sanction	April 2019	August 2019
Complete Requirements and Design	March 2020	July 2020
Complete D&I Project Sanction	March 2020	April 2020
Business Process Design	April 2020	April 2020
Factory Acceptance Testing	October 2020	October 2020
Future Vision/OMS Process Refresh	October 2020	October 2020
Site Acceptance Testing	February 2021	March 2021
Complete Development and Implementation	January 2021	January 2021
Complete User Acceptance Testing	June 2021	April 2021
Change Management/Training	March 2021	May 2021
Move to Production / Go Live Phase 1	June 2021	May 2021
Hyper Care Post Go-Live Support	June 2021	June 2021
Annual Post Go-Live Feeder Additions	December 2021	December 2021

IV. Term 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 DERs 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.

Fuel Type	***Total Units***	***Nameplate AC Rating (kW)***	***Capacity Factor***	***Est Annual Output***
Bio Gas	7	3,010	73.30%	19,327,451
Diesel	4	655	40.00%	2,295,120
Fuel Oil	2	5,350	40.00%	18,746,400
Hydro	11	5,421	37.40%	17,760,497
Hydrogen	1	30	-	-
Landfill Gas	8	19,555	73.30%	125,564,219
Natural Gas	159	92,643	57.60%	467,455,857
Propane	2	10	57.60%	50,458
Solar	66,618	1,359,874	13.40%	1,596,274,202
Solar with Battery	1,567	150,103	13.40%	176,196,563
Wind	51	20,638	37.40%	67,615,533
Energy Storage	48	9,653	-	-
Total	**68,478**	**1,666,942**		**2,491,286,299**

	2018	2019	2020	2021
Fuel Type	***Total Units***	***Total Units***	***Total Units***	***Total Units***
Bio Gas	7	7	7	7
Diesel	5	5	5	4
Fuel Oil	2	2	2	2
Hydro	10	10	11	11
Hydrogen	-	-	1	1
Landfill Gas	7	6	8	8
Natural Gas	146	157	162	159
Propane	2	2	2	2
Solar	47,252	53,305	59709	66,618
Solar with Battery	125	305	682	1,567
Wind	53	56	57	51
Energy Storage	-	10	39	48
Total	**47,609**	**53,865**	**60,685**	**68,478**

	2018	2019	2020	2021
Fuel Type	***Nameplate AC Rating (kW)***	***Nameplate AC Rating (kW)***	***Nameplate AC Rating (kW)***	***Nameplate AC Rating (kW)***
Bio Gas	3,010	3,010	3,010	3,010
Diesel	1,675	1,675	1,675	655
Fuel Oil	5,350	5,350	5,350	5,350
Hydro	5,087	5,087	5261	5,421
Hydrogen	-	-	30	30
Landfill Gas	17,230	10875	7085	19,555
Natural Gas	81,055	97456.7	91,971	92,643
Propane	10	10	10	10

Solar	1,013,072	1,097,710	1186289.264	1,359,874
Solar with Battery	1887.8	27484.12	59828.865	150,103
Wind	20,301	20,311	21070.75	20,638
Energy Storage	-	534	8342	9,653
Total	**1,148,677**	**1,269,503**	**1,389,923**	**1,666,942**

B. System Automation Saturation

The 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.

Metric	2018	2019	2020	2021
System Automation Saturation	478	440	434	405

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.

Metric	2018	2019	2020	2021
Percentage of Circuits w/ Installed Sensors	57%	59%	61%	62%

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.

The Company is providing the term summary of planned versus actual devices installed as of December 31, 2021 in Tab 5.e. Spending – Cumulative in the attached Department Annual Report Template. 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.

The Company is providing the term summary of planned versus actual spending installed as of December 31, 2021 in Tab 5.e. Spending – Cumulative in the attached Department Annual Report Template. 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.e. Spending – Cumulative in the attached Department Annual Report Template provides the deviation between actual and planned deployment for the term. Refer to columns D-L.

The Company detailed the causes for deviation from the planned deployment in each of the investment area sections and identified significant cost variances in Section I.B and Section I.D.

G. Projected Deployment for The Remainder of the Four-Year (2018-2021) Term

This metric is designed to show National Grid's projected deployment for the four-year term under its GMP on a year-by-year basis. Since the 2018-2021 term has been completed and this is the Term Report, this section is not applicable this year.

V. Distributed Energy Resources ("DERs")

A. Overview of DERs on Distribution System

The Company currently has over 68,000 interconnected DERs on its system with a total nameplate capacity of 1.67 GW. The Company currently has over 7,000 active applications representing an incremental 1.67 GW. Over 5,000 of the active applications are driven through the new SMART Program representing over 524.9 MW in the interconnection queue. Storage facility applications under the SMART program account for nearly one-third of active SMART applications. Additionally, 395 applications and approximately 280 MW of incremental capacity in the interconnection queue are attributed to storage facilities intent on participating in other incentive programs.

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 #1: Bottom-Up Feeder Level Forecasting allows for more accurate forecast.

- The Company added Bottom-Up forecasting capabilities in addition to its existing Top-Down forecasting capabilities for distribution planning of feeders in the Commonwealth. The addition of this capability enhances area specific focused DER forecasting adoption. For example, a residential feeder ground mount DG forecast will take into consideration land limitations in the town, such as wetlands.

Lesson #2: DER Integration solutions will be dependent on Economic Feasibility

- Among the top concerns identified by the solar developer community is that DER control and management may erode the revenue potential of solar development. National Grid has engaged EPRI on a special project to explore the technical and economic feasibility of actively managing solar resources. This assessment is helping the Company determine how to model and optimize power output from renewable DERs based on real-time decisions with the ability to actively limit DER output, including curtailment based on system conditions to avoid thermal constraints. As part of this project, EPRI is exploring the technical and economic feasibility of actively managing solar resources. This assessment will help the Company determine how to optimize power output from renewable DERs better based on real-time decisions on DER output modifications, including curtailment based on system conditions to avoid thermal constraints and will likely improve the DER developer experience if the Active Resource Integration demo is approved.

Lesson #3: Process Improvements led to Improved DER Integration

- The Company enacted several process improvements that have led to improved customer satisfaction and improved DG integration. The following are a list of the most significant of them.

- Increased Availability for Customer Concerns: For any customers that have a question or concern related to their DG application beyond the scope of what the Customer Energy Integration (CEI) representative can address, the Company has created a DG Ombudsperson role to assist. Customers can reach out to the Ombudsperson directly, or the CEI representative may escalate as well in situations where they need assistance. The Ombudsperson takes point on coordinating internal groups as needed and developing fair solutions and compromises. All escalated items are tracked and monitored to ensure the best overall experience. Where appropriate, engineering teams are made available to the customer for discussion to work through questions directly and identify solutions and path forward.

- Process Efficiencies – Alignment of Capital Delivery teams' activities with DG process: National Grid has taken steps to further integrate construction management processes into the DG process, enabling interactions earlier during the DG study phase. This allows for more robust information for customers on necessary system modifications and additionally can allow for a more seamless transition into construction activities after study completion.

- Customer Support - Key Account Managers: National Grid recognizes that certain developers have larger sized and/or more complex project portfolios than others. In an effort to provide the appropriate level of customer support, National Grid has established a Key Account framework whereby those large/complex portfolio customers have a dedicated Customer Energy Integration (CEI) representative. This CEI representative has regularly scheduled touchpoints with the developer to review the entire portfolio and provides dedicated support as needed.

Lesson #4: Reducing Interconnection Time by Adapting to Customer Preferences

- Customers have expressed an interest in an option to perform the design and construction activities related to National Grid system modifications, which historically have been exclusively performed by National Grid at the customer's cost. The developer community believes that certain time and/or cost efficiencies may be gained through the customer self-performance approach. National Grid has subsequently established a pilot that will allow for customer design and construction of select system modifications. Development of the pilot and process criteria surrounding it has been developed through the second half of 2021 with collaboration between National Grid and industry representatives through the Northeast Clean Energy Council (NECEC). The period to request participation in the pilot was opened through February of 2022, with project selection occurring in March 2022, kicking projects off expected in April 2022.

Lesson#5: Proactively Participating in DER Integration Policy to allow for better solutions: The Company has taken a proactive approach during the ISO-NE FERC Order 2222 Compliance Process

- National Grid has been an active and vigilant participant throughout the ISO-NE stakeholder engagement process for FERC Order 2222 since the topic was initially introduced at the NEPOOL Markets Committee in December 2020. Since then, the Company has taken a leading role among the New England utilities on this topic, offering multiple rounds of written comments and sponsoring several presentations on behalf of the Company and the other New England utilities at formal and informal stakeholder meetings. The Company has also been proactive in updating the DPU on developments and potential impacts related to Order 2222 in Massachusetts, engaging with the DPU through both (a) informal meetings expressing our position on the ISO-NE compliance approach, and (b) a written proposal documenting impacts and associated required investments for Order 2222 via the Company's 2022-2025 Grid Modernization Plan in D.P.U. docket 21-81.

- The purpose of the Company's participation has been to ensure that the voice of the distribution utility and all of the customers served (i.e., both DER and non-DER customers) are represented throughout every step of the ISO-NE market development process. Thus, several of our comments have been to set expectations appropriately about what the distribution utilities can and cannot support on "Day 1" of market implementation, including indicating which market design elements would require substantially new distribution utility capabilities and investments for which not yet authorized for cost recovery to implement. The Company comments also intended to "future-proof" the market design such that associated market rules did not potentially restrict the ability of the Company from fully utilizing the Company's Grid Modernization investments (i.e., DERMS, ADMS, etc.) required to manage a safe and reliable DER-heavy distribution network in the future.

- ISO-NE and the broader stakeholder community was generally receptive and appreciative of the comments raised by the Company and the New England utilities, and many of our concerns were adopted by ISO-NE in their compliance filing to FERC. As a result, the Company is supportive of the ISO-NE compliance filing and voted in support of the compliance approach at the NEPOOL committee meetings. The Company looks forward to future developments at FERC and ISO-NE on this topic over the coming months and years.

Lesson #6: Advancing DER management and integration can reduce DER integration costs

- Alongside the Company's efforts to evolve its integrated planning process and cost allocation mechanisms for distributed generation through DPU 20-75, National Grid has identified that significant customer value can be unlocked if the Company can actively manage DER operation to enhance utilization of existing system capacity outside of peak load and generation periods, potentially reducing costs and accelerating timing of interconnection requests from distributed generation and energy storage developers. The developer stakeholder community has voiced interest with the utilities to offer alternative interconnection options in order to optimize their project economics, balancing interconnection costs and market revenues. National Grid believes such an interconnection option could be driven by an initial group of products within the Company’s overall DERMS roadmap and leverage an agile framework that continues to build upon developer input that National Grid has recently received and available market research of similar offerings from other peer utilities. The Company has already identified several new software tools, field devices and processes that may be required to appropriately study, implement and operate these active DER management offerings, which the Company is first planning to investigate for utility-scale solar facilities through its Active Resource Integration project filed under its 2022-2025 Grid Modernization Plan, with an intent to expand to other DER such as energy storage facilities.

VI. Performance Metrics

A. Description of 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.

The Department also ordered the Distribution Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the Distribution Companies' preauthorized GMP investments and their progress toward meeting the Department's grid modernization objectives. D.P.U. 15-122, at 204-205. Guidehouse (formerly Navigant Consulting, Inc.) is completing the evaluation to ensure a uniform statewide approach and to facilitate coordination and comparability across the Distribution Companies.

The data supporting the performance metrics have been provided to the Guidehouse evaluation team by the Company. Results of the Monitoring and Control ("M&C"), Distribution Automation ("DA"), Communications and IT/OT, Volt Var Optimization (VVO) and Advanced Distribution Management System ("ADMS") investment areas are expected to be shared by Guidehouse in June 2022.

2.1 VOLT VAR OPTIMIZATION AND CONSERVATION VOLTAGE REDUCTION BASELINE – For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The first VVO M&V results for the Stoughton station were captured over three seasons throughout the year, Winter, Spring and Summer. The peak benefits were realized during the winter months December 1, 2020, through March 31, 2021. Overall, the average outcome across the Stoughton substation was a 0.58 percent observed power decrease and a 0.91 percent voltage decrease. This initial M&V is being reviewed and shared with Guidehouse to develop the overall VVO performance outcomes. The results will establish 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 - For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The results will establish a baseline impact factor required to quantify the energy savings achieved by VVO.

2.3 VVO PEAK LOAD IMPACT - For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The results will establish a baseline impact factor required to quantify the peak demand impact VVO/CVR has on the system.

2.4 VVO – DISTRIBUTION LOSSES WITHOUT AMF (BASELINE) - For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The results will establish a baseline impact factor required to quantify the distribution losses.

2.5 VVO POWER FACTOR - For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The results will establish a baseline impact factor required to quantify the power factor.

2.6 VVO ESTIMATED VVO/CVR ENERGY AND GHG IMPACT - For the GMP term, the Company had a total of four substations and 27 feeders equipped with the VVO technology. The results will establish a baseline impact factor for each VVO-enabled circuit which will be used to quantify the energy savings and greenhouse gas ("GHG") impact measures.

2.7 INCREASE IN SUBSTATIONS WITH DISTRIBUTION MANAGEMENT SYSTEM ("DMS") POWER FLOW AND CONTROL CAPABILITIES – The Company has enabled DMS power flow capability on 276 feeders during the 2018-2021 term. National Grid's ADMS model functions differently than how this metric was intended to measure completeness. The ADMS uses telemetered data from field devices paired with the ADMS electric network model to run an operational load flow on enabled feeders (276 at calendar 2021 end). This allows users to view load flow results on the real-time electric network model or run a load flow in simulation mode to study future switched grid reconfigurations to ensure no voltage or thermal violations and that grid configuration is optimal. We do not presently run a continuous automatic load flow. All feeders enabled for ADMS load flow are qualified and tested prior to being transitioned to operational use and are run through a series of screenings by our engineering team including the following: data check on device limits and ratings, line ratings, peak load and light load qualification, comparison of ADMS load flow outputs and solar/DER outputs to telemetered field data, verification of no abnormal voltage or thermal violations while feeders are in normal state. The Company is providing the term summary of feeders enabled as of December 31, 2021 in Tab 7. DMS Power Flow in the attached Department Annual Report Template.

2.8 CONTROL FUNCTIONS IMPLEMENTED BY CIRCUIT (VVO, AUTO RECONFIGURATION) - The Company has not enabled DMS control functions during the 2018-2021 term period.

2.9 NUMBERS OF CUSTOMERS THAT BENEFIT FROM GMP FUNDED DISTRIBUTION AUTOMATION DEVICES - The Company has enabled 31 feeders representing 16 ADA schemes from 2019 through 2021.

Substation	Feeder ID	# of Customers Benefiting from DA Devices	Types of DA Devices Benefiting Customers
Ayer	01-201W2	3412	OH DA w/Ties, OH DA w/out Ties, Feeder Monitor
Belmont	07-98W19	217	OH DA w/out Ties
Chartley Pond	05-8L3	2627	OH DA w/out Ties
Dupont	07-91W49	4773	OH DA w/Ties
E. Beverly	12-51L3	1970	OH DA w/out Ties, Feeder Monitor
E. Bridgewater	07-797W19	2549	OH DA w/out Ties
East Boxford	14-33L1	990	OH DA w/Ties, OH DA w/out Ties
East Tewksbury	14-59L6	1534	OH DA w/out Ties
Field St	07-1W5	3195	OH DA w/out Ties
Fitch Rd.	01-216W6	1410	OH DA w/out Ties
Hoover Street	14-21L1	2940	OH DA w/out Ties
Maplewood	12-16W6	5696	OH DA w/Ties, OH DA w/out Ties, Feeder Monitor
Melrose	12-25W4	4543	OH DA w/out Ties, Feeder Monitor
Metcalf Sq.	12-96W1	3890	OH DA w/out Ties, Feeder Monitor
N. Beverly	12-18L2	1602	OH DA w/Ties, OH DA w/out Ties
North Dracut	14-78L1	2272	OH DA w/Ties, OH DA w/out Ties
Read Street	05-9L1	2194	OH DA w/Ties, OH DA w/out Ties

Read Street	05-9L3	1357	OH DA w/Ties, OH DA w/out Ties, Feeder Monitor
Read Street	05-9L6	2001	OH DA w/out Ties
Saugus	12-23W2	3059	OH DA w/Ties, OH DA w/out Ties
Stoughton	07-913W43	2119	OH DA w/Ties, OH DA w/out Ties
Stoughton	07-913W69	3607	OH DA w/out Ties
Union Street	05-348W7	857	OH DA w/Ties, OH DA w/out Ties,
Union Street	05-348W8	1398	OH DA w/out Ties
W. Salem	12-29W1	3782	OH DA w/out Ties, Feeder Monitor
West Quincy	07-3W3	2166	OH DA w/Ties, OH DA w/out Ties
Westford	14-57L2	1761	OH DA w/Ties, OH DA w/out Ties, Feeder Monitor
Westford	14-57L3	3521	OH DA w/out Ties, Feeder Monitor
Winthrop	12-22W5	543	OH DA w/Ties, OH DA w/out Ties
Woodchuck Hill	14-56L1	2017	OH DA w/out Ties
Woodchuck Hill	14-56L3	1968	OH DA w/out Ties

2.10 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS' EFFECT ON OUTAGE DURATIONS - The Company has enabled 31 feeders representing 16 ADA schemes from 2019 through 2021. There were four mainline events that caused operations of the ADA during the 2021 plan year and for the term which would have a direct effect on outage durations. All four events reduced the event CMI by 40% or more, and an additional three operations in early 2022 produced similar results.

SAIDI Without MED

			Baseline						
Feeder _ID	Substation	Active	2015	2016	2017	3-yr Avg	2020 SAIDI	2021 SAIDI	Diff (baseline - 2021)
07-913W43	Stoughton	10/26/2020	50.34	239.43	132.66	140.81	332.01	30.91	109.90
07-913W69	Stoughton	10/26/2020	113.53	301.67	22.53	145.91	389.27	97.36	48.55
14-56L3	Woodchuck Hill	12/31/2020	135.69	485.16	305.38	308.74	255.24	345.70	-36.96
14-33L1	East Boxford	12/31/2020	62.82	403.18	854.92	440.31	573.67	241.36	198.95
07-98W19	Belmont	2/5/2021	0.00	8.00	51.06	19.69	26.53	28.83	-9.14
07-797W19	E. BridgeWater	2/5/2021	109.34	172.68	25.49	102.50	690.07	29.89	72.62
14-56L1	Woodchuck Hill	2/12/2021	23.64	6.03	426.61	152.09	246.52	13.71	138.39
14-59L6	E. Tewksbury	2/12/2021	143.05	238.92	295.92	225.96	104.84	56.62	169.34
07-91W49	Dupont	3/12/2021	6.70	26.99	6.17	13.29	136.65	15.45	-2.16
14-57L2	Westford	3/18/2021	91.74	194.82	82.16	122.91	978.14	137.19	-14.28
14-57L3	Westford	3/18/2021	117.14	406.34	186.08	236.52	1256.90	91.88	144.64
14-78L1	North Dracut	3/24/2021	127.72	48.81	15.96	64.17	180.69	10.85	53.31
14-21L1	Hoover St	3/24/2021	192.17	81.00	26.71	99.96	99.85	29.96	70.00
12-29W1	W. Salem	3/31/2021	7.81	142.44	56.97	69.08	71.81	58.47	10.61
12-23W2	Saugus	3/31/2021	7.55	438.59	50.23	165.46	24.87	19.68	145.78
05-348W7	Union St	7/12/2021	-	-	0.00	0.00	207.28	113.18	-113.18
05-348W8	Union St	7/12/2021	-	-	0.00	0.00	88.36	48.48	-48.48
07-3W3	West Quincy	7/22/2021	6.91	4.94	103.17	38.34	2.49	7.03	31.31
07-1W5	Field St	7/22/2021	24.04	109.34	120.41	84.59	359.67	27.73	56.86
12-22W5	Winthrop	8/13/2021	6.82	63.36	22.44	30.87	1.36	0.25	30.62
12-96W1	Metcalf Square	8/13/2021	188.46	154.35	462.55	268.45	466.95	6.89	261.56
05-9L3	Read St	10/7/2021	12.01	52.21	4.30	22.84	93.22	196.29	-173.44
05-9L1	Read St	10/7/2021	81.74	82.98	70.42	78.38	369.19	137.79	-59.41
05-8L3	Chartley Pond	10/7/2021	66.33	132.71	46.23	81.76	722.99	145.45	-63.69
05-9L6	Read St	10/7/2021	9.66	157.41	146.24	104.44	288.94	75.87	28.57
01-216W6	Fitch Rd	12/6/2021	262.00	100.60	201.55	188.05	627.50	239.57	-51.52
01-201W2	Ayer	12/6/2021	122.03	585.00	205.98	304.33	823.73	267.53	36.80
12-16W6	Maplewood	12/16/2021	5.87	9.40	102.92	39.40	217.52	21.54	17.85
12-25W4	Melrose	12/16/2021	53.21	73.37	17.21	47.93	456.57	52.16	-4.23
12-51L3	E. Beverly	12/16/2021	132.15	75.45	149.38	118.99	280.55	251.67	-132.67
12-18L2	N. Beverly	12/16/2021	141.15	250.79	288.94	226.96	60.42	42.11	184.85

SAIDI With MED

			Baseline						
Feeder _ID	**Substation**	**Active**	**2015**	**2016**	**2017**	**3-yr Avg**	**2020 SAIDI**	**2021 SAIDI**	**Diff (baseline - 2021)**
07-913W43	Stoughton	10/26/2020	50.34	239.43	749.74	346.50	385.32	648.06	-301.56
07-913W69	Stoughton	10/26/2020	114.34	301.67	31.01	149.01	400.35	101.34	47.66
14-56L3	Woodchuck Hill	12/31/2020	141.90	485.16	3101.24	1242.77	409.17	349.35	893.41
14-33L1	East Boxford	12/31/2020	62.82	403.18	3391.31	1285.77	574.24	564.83	720.94
07-98W19	Belmont	2/5/2021	0.00	8.00	51.06	19.69	26.26	43.29	-23.60
07-797W19	E. BridgeWater	2/5/2021	109.34	172.68	34.61	105.54	692.45	1169.32	-1063.78
14-56L1	Woodchuck Hill	2/12/2021	20.23	6.03	1410.42	478.89	524.16	13.73	465.16
14-59L6	E. Tewksbury	2/12/2021	171.20	238.92	1560.59	656.90	104.74	56.48	600.42
07-91W49	Dupont	3/12/2021	6.71	26.99	62.97	32.22	142.25	1391.28	-1359.06
14-57L2	Westford	3/18/2021	91.74	194.82	909.41	398.66	980.06	138.77	259.89
14-57L3	Westford	3/18/2021	117.18	406.34	620.01	381.18	1286.85	116.00	265.17
14-78L1	North Dracut	3/24/2021	127.72	48.81	1748.61	641.71	198.60	30.41	611.31
14-21L1	Hoover St	3/24/2021	192.17	81.00	1645.86	639.68	100.74	30.08	609.60
12-29W1	W. Salem	3/31/2021	7.81	142.44	73.96	74.74	71.83	95.78	-21.04
12-23W2	Saugus	3/31/2021	7.55	438.59	122.42	189.52	19.85	19.16	170.36
05-348W7	Union St	7/12/2021	-	-	-	-	1336.32	113.62	-
05-348W8	Union St	7/12/2021	-	-	-	-	714.31	48.46	-
07-3W3	West Quincy	7/22/2021	6.91	4.94	103.17	38.34	3.00	254.57	-216.23
07-1W5	Field St	7/22/2021	24.04	109.34	120.86	84.75	359.94	541.15	-456.41
12-22W5	Winthrop	8/13/2021	6.82	63.36	22.44	30.87	1.50	1.06	29.82
12-96W1	Metcalf Square	8/13/2021	189.08	154.35	462.55	268.66	469.46	45.83	222.83
05-9L3	Read St	10/7/2021	12.01	52.21	95.03	53.09	115.51	233.48	-180.40
05-9L1	Read St	10/7/2021	81.74	82.98	333.12	165.95	601.81	208.13	-42.18
05-8L3	Chartley Pond	10/7/2021	66.33	132.71	311.72	170.26	1300.75	324.54	-154.28
05-9L6	Read St	10/7/2021	11.01	157.41	493.89	220.77	401.05	123.09	97.68
01-216W6	Fitch Rd	12/6/2021	-	72.06	244.16	158.11	957.35	250.13	-92.02
01-201W2	Ayer	12/6/2021	122.08	585.00	298.43	335.17	1084.83	273.34	61.83
12-16W6	Maplewood	12/16/2021	5.87	9.40	110.81	42.03	217.21	23.11	18.91
12-25W4	Melrose	12/16/2021	53.21	75.34	34.31	54.29	452.76	53.20	1.09
12-51L3	E. Beverly	12/16/2021	133.41	75.45	421.96	210.27	301.69	900.26	-689.99
12-18L2	N. Beverly	12/16/2021	141.15	250.79	1976.07	789.34	68.25	517.57	271.76

2.11 RELIABILITY-FOCUSED GRID MODERNIZATION INVESTMENTS' EFFECT ON OUTAGE FREQUENCY - The Company has enabled 31 feeders representing 16 ADA schemes from 2019 through 2021. There were four mainline events that caused operations of the ADA during the 2021 plan year and for the term which would have a direct effect on outage frequency.

All four events restored 35% or more customers under the one-minute Massachusetts threshold for frequency, and an additional three operations in early 2022 produced similar results.

SAIFI Without MED

			Baseline						
Feeder _ID	Substation	Active	2015	2016	2017	3-yr Avg	2020 SAIFI	2021 SAIFI	Diff (baseline - 2021)
07-913W43	Stoughton	10/26/2020	0.70	1.18	0.84	0.91	1.59	0.23	0.67
07-913W69	Stoughton	10/26/2020	1.29	2.84	0.10	1.41	3.04	1.41	0.00
14-33L1	East Boxford	12/31/2020	0.12	1.98	3.46	1.85	2.34	1.87	-0.01
14-56L3	Woodchuck Hill	12/31/2020	1.46	1.82	1.58	1.62	1.07	1.61	0.01
07-797W19	E. BridgeWater	2/5/2021	2.26	0.29	0.15	0.90	4.93	0.15	0.75
07-98W19	Belmont	2/5/2021	0.00	0.12	1.94	0.69	0.07	0.44	0.24
14-56L1	Woodchuck Hill	2/12/2021	0.50	0.02	1.04	0.52	1.29	0.81	-0.30
14-59L6	E. Tewksbury	2/12/2021	1.16	1.18	0.95	1.10	0.54	0.62	0.48
07-91W49	Dupont	3/12/2021	0.04	0.31	0.09	0.15	0.69	0.34	-0.19
14-57L2	Westford	3/18/2021	0.58	0.80	0.57	0.65	1.57	0.82	-0.17
14-57L3	Westford	3/18/2021	0.23	1.90	1.34	1.16	3.00	1.30	-0.14
14-21L1	Hoover St	3/24/2021	2.18	0.58	0.05	0.94	0.54	0.12	0.82
14-78L1	North Dracut	3/24/2021	1.45	0.24	0.15	0.61	2.13	0.13	0.49
12-23W2	Saugus	3/31/2021	0.07	2.08	0.15	0.77	0.25	0.36	0.41
12-29W1	W. Salem	3/31/2021	0.06	1.08	1.10	0.75	0.69	0.11	0.64
05-348W7	Union St	7/12/2021	-	-	0.00	0.00	0.89	0.95	-0.95
05-348W8	Union St	7/12/2021	-	-	0.00	0.00	0.19	0.10	-0.10
07-1W5	Field St	7/22/2021	0.15	1.44	3.47	1.69	2.41	0.09	1.60
07-3W3	West Quincy	7/22/2021	0.10	0.03	1.19	0.44	0.02	0.09	0.35
12-22W5	Winthrop	8/13/2021	0.07	1.09	0.03	0.39	0.02	0.00	0.39
12-96W1	Metcalf Square	8/13/2021	3.11	2.09	2.09	2.43	1.28	1.02	1.41
05-8L3	Chartley Pond	10/7/2021	1.08	0.76	0.27	0.70	1.79	0.79	-0.09
05-9L1	Read St	10/7/2021	0.97	0.73	1.08	0.92	2.86	1.08	-0.16
05-9L3	Read St	10/7/2021	0.20	0.60	0.08	0.29	0.64	0.93	-0.64
05-9L6	Read St	10/7/2021	0.06	1.16	1.79	1.00	1.37	0.93	0.07
01-201W2	Ayer	12/6/2021	0.98	3.41	0.83	1.74	3.19	1.38	0.36
01-216W6	Fitch Rd	12/6/2021	3.00	0.41	1.38	1.60	2.21	1.31	0.28
12-16W6	Maplewood	12/16/2021	0.05	0.09	0.72	0.29	0.28	0.36	-0.07
12-18L2	N. Beverly	12/16/2021	1.28	2.44	2.49	2.07	1.91	0.07	2.00
12-25W4	Melrose	12/16/2021	1.02	0.68	0.15	0.61	1.30	1.66	-1.04
12-51L3	E. Beverly	12/16/2021	0.81	0.24	1.26	0.77	3.21	1.22	-0.45

SAIFI With MED

			Baseline						
Feeder _ID	Substation	Active	2015	2016	2017	3-yr Avg	2020 SAIFI	2021 SAIFI	Diff (baseline - 2021)
07-913W43	Stoughton	10/26/2020	0.70	1.18	1.21	1.03	1.71	0.49	0.54
07-913W69	Stoughton	10/26/2020	1.29	2.84	0.18	1.44	3.06	1.43	0.00
14-33L1	East Boxford	12/31/2020	0.12	1.98	5.18	2.43	2.34	2.37	0.06
14-56L3	Woodchuck Hill	12/31/2020	1.51	1.82	2.56	1.96	1.24	1.68	0.29
07-797W19	E. BridgeWater	2/5/2021	2.26	0.29	0.15	0.90	4.94	0.71	0.19
07-98W19	Belmont	2/5/2021	0.00	0.12	1.94	0.69	0.07	0.51	0.18
14-56L1	Woodchuck Hill	2/12/2021	0.48	0.02	2.03	0.84	2.29	0.81	0.03
14-59L6	E. Tewksbury	2/12/2021	1.24	1.18	1.21	1.21	0.54	0.61	0.60
07-91W49	Dupont	3/12/2021	0.04	0.31	0.12	0.16	0.69	0.69	-0.53
14-57L2	Westford	3/18/2021	0.58	0.80	1.31	0.90	1.57	0.83	0.07
14-57L3	Westford	3/18/2021	0.23	1.90	1.55	1.23	3.13	1.38	-0.15
14-21L1	Hoover St	3/24/2021	2.18	0.58	1.05	1.27	0.54	0.12	1.16
14-78L1	North Dracut	3/24/2021	1.45	0.24	1.04	0.91	2.14	0.20	0.70
12-23W2	Saugus	3/31/2021	0.07	2.08	0.24	0.80	0.21	0.38	0.41
12-29W1	W. Salem	3/31/2021	0.06	1.08	1.13	0.76	0.69	0.63	0.12
05-348W7	Union St	7/12/2021	-	-	-	-	2.15	0.95	-
05-348W8	Union St	7/12/2021	-	-	-	-	0.81	0.10	-
07-1W5	Field St	7/22/2021	0.15	1.44	3.47	1.69	2.41	1.09	0.59
07-3W3	West Quincy	7/22/2021	0.10	0.03	1.19	0.44	0.02	0.15	0.29
12-22W5	Winthrop	8/13/2021	0.07	1.09	0.03	0.39	0.02	0.01	0.39
12-96W1	Metcalf Square	8/13/2021	3.11	2.09	2.09	2.43	1.29	1.07	1.36
05-8L3	Chartley Pond	10/7/2021	1.08	0.76	0.39	0.74	2.81	1.06	-0.33
05-9L1	Read St	10/7/2021	0.97	0.73	1.24	0.98	3.89	1.11	-0.13
05-9L3	Read St	10/7/2021	0.20	0.60	0.10	0.30	0.65	1.37	-1.07
05-9L6	Read St	10/7/2021	0.08	1.16	1.94	1.06	2.19	0.97	0.10
01-201W2	Ayer	12/6/2021	0.98	3.41	0.89	1.76	3.49	1.41	0.35
01-216W6	Fitch Rd	12/6/2021	-	0.15	1.42	0.78	2.34	1.39	-0.60
12-16W6	Maplewood	12/16/2021	0.05	0.09	0.74	0.29	0.28	0.38	-0.08
12-18L2	N. Beverly	12/16/2021	1.28	2.44	2.78	2.17	2.06	0.65	1.52
12-25W4	Melrose	12/16/2021	1.02	0.69	0.16	0.62	1.29	1.74	-1.11
12-51L3	E. Beverly	12/16/2021	0.81	0.24	1.38	0.81	3.28	2.22	-1.41

2.12 VVO RELATED VOLTAGE COMPLAINTS PERFORMANCE METRIC AND BASELINE -

The Company does not have an automated system to track voltage complaints but will use the OMS system to retrieve incidents. The current OMS system was installed at the end of the year 2015 providing less than one year's results. The OMS Call results of Non-Outages were pulled from the 20 feeders and three substations to be upgraded with VVO technology. Additional filters were applied to the results to better understand the reason behind the reported incident to be linked to a possible complaint in voltage. Filters were applied to exclude results as follows:

a. Remove blank Caller Comments due to lack of description of incident.
b. Remove the address "1234 Trouble St" as this is a placeholder address and not connected to the premise of incident.
c. Remove UG (underground facilities) from the transformer list.
d. Remove results associated with Motor Vehicle Incidents, Fire, Trees, Storms, and other results that would not have been caused by blue sky activity.

From the reduced results of incidents of customer-reported voltage complaints, particular focus was given to the incidents that included terms such as Voltage, Dim, Flickering, and VRM (Voltage Recorder Monitor). The Company is working towards process improvements and system enhancements to better enable the identification and associated details of customer voltage complaints that may be related to VVO voltage optimization.

Total Voltage Complaints

Substation Name	Baseline (2016 & 2017 Average)	2018	2019	2020	2021
East Methuen	31	16	14	15	22
Maplewood	26	34	50	45	39
Stoughton	28	23	14	24	15
E. Bridgewater	30				39
East Dracut	18				18
W. Salem	19				23
Total	**152**	**73**	**78**	**84**	**156**

App.C.1.0 NATIONAL GRID RELIABILITY-RELATED COMPANY-SPECIFIC - The Company has enabled 31 feeders representing 16 ADA schemes from 2019 through 2021. There were four mainline events that caused operations of the ADA during the 2021 plan year and for the term.

Mainline CMI

			Baseline						
Feeder _ID	Substation	Active	2015	2016	2017	3-yr Avg	2020 CMI	2021 CMI	Diff (baseline - 2021)
07-913W43	Stoughton	10/26/2020	-	115,452	-	38,484	49,896	-	38,484
07-913W69	Stoughton	10/26/2020	123,836	423,461	-	182,432	580,257	85,666	96,767
14-33L1	East Boxford	12/31/2020	-	190,360	173,173	121,178	421,056	136,387	(15,209)
14-56L3	Woodchuck Hill	12/31/2020	116,425	200,667	211,972	176,355	53,055	71,249	105,106
07-797W19	E. BridgeWater	2/5/2021	80,059	-	-	26,686	1,420,623	-	26,686
07-98W19	Belmont	2/5/2021	-	-	2,706	902	249	760	142
14-56L1	Woodchuck Hill	2/12/2021	2,955	-	773,367	258,774	453,231	24,824	233,950
14-59L6	E. Tewksbury	2/12/2021	251,031	162,128	110,337	174,499	-	50,695	123,804
07-91W49	Dupont	3/12/2021	-	45,474	-	15,158	475,400	31,758	(16,600)
14-57L2	Westford	3/18/2021	149,724	188,621	9,842	116,062	1,518,390	138,999	(22,936)
14-57L3	Westford	3/18/2021	238,560	1,032,472	467,750	579,594	4,118,195	55,303	524,291
14-21L1	Hoover St	3/24/2021	187,904	33,490	-	73,798	261,475	-	73,798
14-78L1	North Dracut	3/24/2021	184,617	-	-	61,539	176,659	-	61,539
12-23W2	Saugus	3/31/2021	-	-	-	-	-	17,313	(17,313)
12-29W1	W. Salem	3/31/2021	-	485,012	123,680	202,897	180,432	155,891	47,007
05-348W7	Union St	7/12/2021	-	-	-	-	66,768	77,939	-
05-348W8	Union St	7/12/2021	-	-	-	-	82,474	9,087	-
07-1W5	Field St	7/22/2021	-	271,042	256,243	175,762	1,024,355	68,257	107,504
07-3W3	West Quincy	7/22/2021	-	-	343,645	114,548	-	-	114,548
12-22W5	Winthrop	8/13/2021	-	-	9,768	3,256	-	-	3,256
12-96W1	Metcalf Square	8/13/2021	-	-	1,476,375	492,125	1,686,643	1,847	490,278
05-8L3	Chartley Pond	10/7/2021	62,777	125,186	-	62,654	690,802	207,051	(144,396)
05-9L1	Read St	10/7/2021	160,618	150,575	164,248	158,480	810,162	278,877	(120,396)
05-9L3	Read St	10/7/2021	10,769	46,659	-	19,143	5,010	183,386	(164,243)
05-9L6	Read St	10/7/2021	-	264,762	230,610	165,124	257,704	91,166	73,958
01-201W2	Ayer	12/6/2021	214,284	1,469,009	306,558	663,284	1,153,429	589,884	73,400
01-216W6	Fitch Rd	12/6/2021	-	45,768	255,218	150,493	621,739	248,690	(98,197)
12-16W6	Maplewood	12/16/2021	-	-	420,310	140,103	-	72,977	67,127
12-18L2	N. Beverly	12/16/2021	137,858	231,524	144,095	171,159	21,264	17,929	153,230
12-25W4	Melrose	12/16/2021	209,609	248,168	-	152,592	1,996,180	192,122	(39,529)
12-51L3	E. Beverly	12/16/2021	95,321	-	1,920	32,414	431,674	346,185	(313,771)

B. Lessons Learned/Challenges and Successes

Lessons learned, challenges and successes are detailed within each of the core investment area narratives within Section III.A, above.

VII. Term Summary of Research, Design, and Development

Research and Development ("R&D") work for the National Grid US business aims to advance products, technologies, processes, systems and work methods that may be new to National Grid. This is accomplished by working with internal departments to identify where strategic R&D investment are needed and are more likely to prove beneficial. To achieve these goals, National Grid works in collaboration with technical organizations, academia and vendors in the energy sector that align with National Grid's goals and objectives to provide a safe, reliable, efficient and clean service.

This collaboration has also helped inform the strategic direction in response to jurisdictional requests for electric modernization in the states in which National Grid operates in the United States (Grid Modernization in Massachusetts and Rhode Island, and reforming the Energy Vision in New York). The Company continues to focus R&D on increasing public safety, supporting the integration of renewable resources, protecting the Company's workforce and reducing costs. Research efforts are designed to allow research teams in each state to build on the research of other teams, to reduce cost and allow for a faster pace of technology adoption.

Throughout the term period of 2018-2021, the National Grid electric business continued to invest and participate in several significant pilot projects with the intention of obtaining operational knowledge and experience of technology-driven system impacts, both in Massachusetts and in New York. Below are a few examples of these R&D projects:

Massachusetts-Distribution

Recloser Testing

- The Company worked with the Electric Power Research Institute ("EPRI") to test the Eaton NX-T reclosers used in its ADA program as part of a supplemental project within EPRI's Program 180: Distribution System. Under the project EPRI tested a sample that was provided for laboratory evaluation and analysis. The recloser went through a test program that was developed by EPRI to evaluate the future performance of distribution reclosers. The testing involved performing a series of functional tests and sensor accuracy testing. The results from this testing were as expected for the functional testing and accuracy tests. For example, the voltage measurements were consistent at different currents and were less than 1% for both the internal and external voltage sensors, which is better than what has been seen in some of the other reclosers tested as part of EPRI testing and evaluation.
- The next step in the testing was to perform accelerated aging on the recloser to understand how the unit may degrade over time. The recloser was exposed to a multi-stress aging test that

included temperature cycling, salt, fog, and UV radiation. The unit was exposed to the cycle for three months. Once completed the functional and accuracy testing will be repeated.

- The final step in the evaluation of the NX-T recloser is to systematically disassemble the recloser to look for potential degradation mechanisms and to review the overall design of the recloser. The review will include chemical analysis of selected recloser components. The results from this research will provide an understanding of the long-term performance of these new reclosers. Testing and evaluation of this new recloser standard will continue into 2021. To date the testing of this new National Grid Standard recloser has been favorable and we expect the continued testing and evaluation into 2021 to show positive results.

The picture below is of the multi-stress aged Eaton NX-T provided to EPRI by National Grid.

Solar Phase 1, 2 and 3 Programs

- Under the Company's 'Solar Phase 1, 2 and 3 programs, the Company contracted and built approximately 35MW of PV solar and 6.2MW/12MWh of Energy Storage systems as part of the Company-owned facilities portfolio. The facilities are used to explore new technologies that can help reduce the interconnection cost and time for future PV solar projects. The research also aims to help the Company move from interconnecting DER to integrating it. Among the technologies researched are Smart Inverters, Energy Storage, Dynamic VAR STATCOMS, Plant Level Controllers and Dual Axis PV tracking. To enhance the learning experience the Company partnered with industry leaders such as EPRI, Sandia National Laboratories (Sandia) and Fraunhofer Gesellschaft (Fraunhofer).

  The research findings from National Grid's Solar Program can be found at:
  https://www.nationalgridus.com/massachusetts-solar/document-library

- The program won two awards in 2020:
  1. The 2020 Digitalization/Technology Adoption Award by Power Magazine and was highlighted in the following article: https://www.powermag.com/team-and-individual-award-winners-recognized-at-experience-power/
  2. The Game Changer Award at the 2020 Connected Plant Conference and was highlighted in the following article: https://www.connectedplantconference.com/2020-game-changers/

- Piloting an Active Resource Integration Project at Solar Phase 2 and 3 locations in Massachusetts and at the Peterboro substation in New York to test the ability to increase the amount of solar DG integrated into the distribution system in constrained areas via development of curtailment capabilities.

EPRI & Centre for Energy Advancement through Technological Innovation ("CEATI") Programs

- National Grid is heavily engaged on several EPRI & CEATI programs, including bulk system renewables, DERs integration, planning and asset management, energy storage, asset management for transmission and distribution, system automation and integrating emerging technologies.

Novel Fault Detection Technology

- Piloting a novel technology that enables National Grid to detect emerging faults on its distribution electric network prior to service disruptions. The successful completion of this pilot will improve the system reliability of a distribution feeder that is experiencing more than usual electric service disruptions.

R&D Awards

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 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.

Massachusetts-Transmission

Spot Robot

- Working with Boston Dynamics National Grid deployed the "Spot Robot" at its Sandy Pond HVDC station, which is responsible for importing almost 2,000MW of clean hydroelectricity into New England every day. Currently technicians inspect the thyristors twice a year visually through windows looking into a hall, during two planned outages a year.

The Spot robot can be in the hall when energized. The robot can walk around the full floor area of the thyristor hall, affording the technicians full viewing angles of the equipment which was impossible to view through the windows alone. The robot also conducts thermal scans. With both its high-resolution optical cameras and sensors it can pick up on very small water leaks (which were before difficult to detect visually) and identify hot spots (places of possible mechanical fatigue). This is all without entering the environment such that the station can stay in operation and energized.

The pilot of the robot was successful, and the Company is collaborating with Boston Dynamics to have two robots at the station. One of the robots will be permanently in the thyristor hall, and the other will be used in the DC yard, which can also be used to pilot other use cases at the facility.

Smart Valve

- Smart Wires manufactures a power flow control device called the Smart Valve. Smart Valve are Flexible Alternating Current Transmission System devices that use power electronics to "push and pull" power over a transmission network thus providing flexible operations over AC lines without the need to build additional capacity (e.g., reconductoring, new lines, or other typical upgrades).
- National Grid US deployed the SmartValve system on a 69kV line near the Fitch Road substation (in Lancaster north of Worcester). The deployment will give operational experience

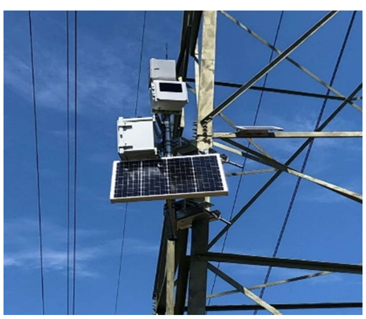
with the technology, prove out the capabilities and discuss use of the technology with ISO-NE. (In parallel, but separate, the Company is working with DOE Idaho National Labs to address and mitigate potential cybersecurity issues with installation of line monitoring, sensors, and power flow control devices on the network).

Kinetrics Line Corrosion Testing Service

- National Grid has successfully piloted the Kinetrics line corrosion testing service to test the ability of the technology to be used in collecting data online corrosion that could be used to prioritize line reconductoring and to avoid destructive line corrosion testing.

Dynamic Transformer and Line Rating Technologies

- National Grid has successfully piloted the dynamic transformer rating technologies at the Sandy Pond substation to test the ability of the technologies to be used in transmission control center and transformer operations and maintenance. This technology enables National Grid to develop condition-based maintenance schedules for transformers to avoid unexpected transformer failure, which can cause significant power outages.
- National Grid has successfully piloted the dynamic line rating technologies on two selected transmission lines to test the ability of the technologies to be used in collecting data on the dynamic ratings of the line that could be used to optimize operations and line switching. This technology enables National Grid to potentially relieve transmission network congestion and aligns with the Company's mission to decarbonize the electric sector.



Digital Substations

- Over the next 10 years National Grid will be deploying up to 20 digital substations in Massachusetts in a transition to fully digital substations on the transmission network, which will utilize the IEC 61850 communications standard. The digital substation reduces construction and operation costs as well as engineering and construction time, increases system flexibility, and helps facilitate the large-scale incorporation of renewable power.