Fitchburg Gas and Electric Light Company (d/b/a Unitil)

Grid Modernization Plan Annual Report

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

Dated: 5-1-2019

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Acronyms

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure

API – Application Programming Interface

CIS – Customer Information System

CVR – Conservation Voltage Reduction

DA – Distribution Automation

DER – Distributed Energy Resource

DERMS – Distributed Energy Resource Management System

DPU – Department of Public Utilities

FAN – Field Area Network

FLISR – Fault Location, Isolation, and Service Restoration

GIS – Geographic Information System

GPS – Global Positioning System

GMP – Grid Modernization Plan

IVR – Integrated Voice Recognition

LTC – Load Tap Changer

OMS – Outage Management System

SCADA – Supervisory Control and Data Acquisition

VAr – Volt Ampere Reactive

VVO – Volt VAr Optimization

WFM – Workforce Management

1 INTRODUCTION

In D.P.U. 12-76, the Massachusetts Department of Public Utilities ("Department") ordered Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid"), Fitchburg Gas and Electric Light Company d/b/a Unitil, and NSTAR Electric Company d/b/a Eversource Energy ("Eversource") (together the "Companies") to file a Grid Modernization Plan ("GMP"). In compliance with the Department Orders in DPU 12-76 on August 19, 2015, Fitchburg Gas and Electric Company, d/b/a/ Unitil (the "Company") submitted a comprehensive GMP that described a scope and schedule for Grid Modernization investments.

At the time of its submission, there was no procedural schedule indicating an expected date of approval of the submitted GMPs. As the Department had made clear in D.P.U. 12-76-B that it "will review each filing in a separate adjudicatory proceeding to ensure that each GMP is consistent with the Department's directives," (D.P.U. 12-76-B at 51), the Company awaited the conclusion of the adjudicatory process and issuance of a final order before taking steps to modify or implement its GMP. The Company did not want to invest in and implement a project without formal approval from the Department.

On May 10, 2018, the Department issued D.P.U. 15-120; D.P.U. 15-121; D.P.U. 15-122 (the "Order") approving GMPs for the Companies. In the Order, the Department preauthorized grid-facing investments over three-years (2018-2020) and adopted a three-year (2018-2020) regulatory review construct for preauthorization of Grid Modernization investments. See Order, at 106-115.

The Department's Order identified which investments were supported and preapproved and which projects required more research and investigation. The Company appreciates this direction from the Department. The Company's decision to wait for issuance of an order prior to implementing any of its planned GMP investments was prudent, since not all of the proposed investments were approved by the Department.

1.1 PROGRESS TOWARDS GRID MODERNIZATION OBJECTIVES

The Company's approach to its GMP consisted of a higher level analysis which identified and estimated projects and benefits. The Company indicated in its GMP that investments identified would require more detailed analysis and planning to better develop project scope, schedule, and estimates.

Since the time that the Order was issued, the Company has been working to re-evaluate its GMP to determine if the projects are still appropriate from a scope, schedule and estimate basis. This has included developing project teams, review of the initial GMP, meeting with vendors, developing designs, specifications, and estimates.

This first Annual Grid Modernization Report covers activities in 2018 and describes the Company's progress towards implementing its Grid Modernization Plan. The report begins with the Company's approach to implementing its GMP, describes the cost and performance tracking measures adopted and the project approval process. The next section of the report describes in more detail the implementation of grid modernization investments by investment category. Section 4 of the report describes and reports on statewide and company specific infrastructure investments. Section 5 describes an overview of the DERs and lessons learned from integrating DERs. Section 6 describes the performance metrics as approved by the Department. The final section of the report describes any research, design, and development activities that the Company may be undertaking.

1.2 SUMMARY OF GRID MODERNIZATION DEVELOPMENT (ACTUAL V. PLANNED)

The Company filed its GMP in August 2015 with the expectation of approval in 2016 and plan implementation in 2017. As described above, the Company's took a higher level approach to identifying and estimating projects and benefits. The Company anticipated time after receipt of an order of approval to complete more detailed design and analysis prior to starting the first year implementation of the GMP.

As described above, the Order was issued in May 2018, and provided that "the Companies' current three-year grid investment plan will cover calendar years 2018, 2019, and 2020." (Order at 114.) This effectively required the Company to undertake its more detailed design and analysis during the first year (2018) rather than beginning implementation of its GMP.

Since the Order was issued, the Company has been working on the more detailed design and analysis required before it can confidently implement the GMP investments identified in its GMP. The progress towards implementing each of the grid modernization investments is summarized below:

<u>Monitoring and Control Investment Category</u>

The Monitoring and Control investment category includes two projects from the Company's GMP. The first project is a Supervisory Control and Data Acquisition (SCADA) project to expand the coverage and functionality of Company's SCADA system. The second project is to further integrate OMS with the Company's Advanced Metering Infrastructure (AMI) system.

Presently, SCADA is already implemented to some extent at some FG&E substations, and not at all at others. Furthermore, at many substations that presently have some level of existing SCADA capability, it is not complete to the extent intended under the GMP. Therefore, this project will add SCADA at those substations that do not presently have it, and expand SCADA capabilities at other substations where it is presently incomplete.

This OMS integration with AMI project is still in the initial stages. In 2018, the Company worked closely with its AMI vendor to identify a combination of data points available on the meter and it's collectors along with various correlating data points (environmental and coincident) to build a model that can accurately confirm suspected outages and electronically qualify them.

Volt/VAr Optimization investment Category

The Volt/Var Optimization investment category includes installing automated controls on all voltage and reactive power equipment on all distribution circuits. This includes controls of all capacitor banks, voltage regulators and transformer load tap changers (LTCs). Voltage and Energy monitors will also be installed at strategic locations on the circuits. Unitil has assigned an internal project manager and assembled a project team of internal employees to implement VVO. Because the VVO is integrated with the ADMS and likely monitored and controlled through the SCADA system, with communication media installed as part of the FAN, the VVO team is coordinating its efforts closely with these teams. This team is in the process of developing the VVO project scope and detailed project schedule. A prioritization model has been developed to inform the order in which the system should be implemented.

Advanced Distribution Management System Investment Category

The ADMS investment category includes two projects from the Company's GMP. The first project is an ADMS project to allow for more measurement and control of the distribution system. The second project is to implement a Distributed Energy Resource Management System (DERMS) which will enable the Company to improve situational awareness and operational intelligence for this increasingly important resource.

No work was completed on the ADMS in 2018. However, the Company has assigned an internal project manager and assembled a project team of internal employees. This team is in the process of meeting with vendors, developing the ADMS project scope and schedule, and issuing a RFP for the procurement and implementation of an ADMS.

The Company's filed GMP does not contemplate the DERMS project to be implemented until the fifth year of the plan. However, the Company is evaluating the ADMS systems with respect to its ability to implement DERMS functionality in the future. The Company has set a priority on implementing and ADMS, SCADA and VVO prior to integrating DERMS. The Company will report on further progress in future annual reports.

Communications Investment Category

This project consists of installing a FAN, including communications between collectors and endpoint devices (meters and distribution devices), and backhaul communications from collectors at each substation to the central office. In the context of the modern grid, communications is the glue that makes it possible for all parties to interact and share information.

The Company is seeking additional communication expertise to evaluate the requirements and design a FAN for the entire Massachusetts service territory. A specification was developed to request proposals (RFP) from vendors for field area network consulting services. The Company developed a weighted decision matrix to evaluate the various proposals. The FAN project team evaluated each of the proposals and filled out the evaluation matrix. The top vendors were invited into the Company to provide a presentation and allow for the project team to ask more questions. The project team adjusted their scores in the evaluation matrix following the information from the presentations. The Company selected a vendor at the end of 2018.

The Company will be hiring a Network Engineer in 2019 (which will be an incremental staff addition to the IT group) who will be focused on the deployment and management of the FAN. This employee was identified in the Company's GMP.

Workforce Management Investment Category

The Company's GMP includes a workforce and asset management program aimed to improve performance of operations and infrastructure. One project identified for the program includes a mobility platform for storm damage assessment that can integrate damage information with the outage management system (OMS) and work order process to improve situational awareness and the speed of restoration. This Mobile Platform - Damage Assessment Tool will help the Company make quicker, better-informed decisions and is aimed to ensure operational efficiency and maintain strong restoration performance.

The project team has been developed to evaluate different products capable of meeting the Company's objectives. The project team developed an RFP and issued it to vendors for formal proposals. An initial screening process was used to separate the proposals into three tiers. The evaluation criteria developed for this project and vendors consisted of a combination of many technical and operational requirements and features. From this evaluation, several vendors were invited into the Company to provide a presentation on their proposal so that the project team could get questions to their answers. Following the vendor presentations, the evaluation matrix was updated.

1.3 SUMMARY OF SPENDING (ACTUAL V. PLANNED SPENDING)

This section of the report summarizes the actual versus planned spending from a capital spending as well as an incremental O&M spending basis.

1.3.1 CAPITAL SPENDING (ACTUAL V. PLANNED SPENDING)

As previously described, the Company has been working on more detailed design and analysis required before it can confidently implement the GMP capital investments identified in its GMP. Table 1 below demonstrates the actual spending versus the plan.

	Actual/Forecasted Capital Spending			
	2017	2018	2019	2020
Monitoring and Control				
SCADA				
Original Plan Spending	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Actual/Forecast Spending	$ -	$ -	$ 720,000	$ 135,000
OMS Integration with AMI				
Original Plan Spending	$ 52,000	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ 70,000	$ 35,000
Volt VAr Optimization				
VVO				
Original Plan Spending	$ 739,000	$ 739,000	$ 739,000	$ 739,000
Actual/Forecast Spending	$ -	$ -	$ 739,000	$ 739,000
Advanced Distribution Management System				
ADMS				
Original Plan Spending	$ -	$ -	$ 700,000	$ 700,000
Actual/Forecast Spending	$ -	$ -	$ -	$ 700,000
DERMS				
Original Plan Spending	$ -	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ -	$ -
Field Area Network				
Field Area Network				
Original Plan Spending	$ 280,000	$ 280,000	$ 280,000	$ 280,000
Actual/Forecast Spending	$ -	$ -	$ 280,000	$ 280,000
Workforce Management				
Mobile Platform Damage Assessment				
Original Plan Spending	$ 300,000	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ 300,000	$ 100,000
Total				
Total				
Original Plan Spending	$ 1,771,000	$1,119,000	$ 1,119,000	$ 1,119,000
Actual/Forecast Spending	$ -	$ -	$ 2,409,000	$ 1,389,000

Table 1 – Planned Versus Actual Capital Spending

As noted in the table above, there is a proposed increase in spending for the SCADA project. The primary reasons for the increase in the estimated capital spending is1) equipment replacements and 2) increased labor and material costs from the initial estimate. The initial estimate did not include any equipment replacements to support the SCADA project. The

Company has identified fifteen (15) substation circuit position upgrades, including eight (8) recloser replacements and seven (7) relaying and control replacements that currently do not have the ability to be connected to SCADA (e.g. hydraulic breakers/reclosers). This equipment will need to be replaced to allow SCADA to be installed.

The OMS Integration with AMI project has identified an increase in the estimate. The increase in estimated costs associated with this project are related to 1) updated labor costs between the original estimate and revised estimate, 2) vendor involvement has increased over original estimates and 3) additional development time associated with the cloud based solution.

Also identified in this table is an increase for the Mobile Platform Damage Assessment project. The estimate in the GMP was based upon preliminary discussions with vendors who provided budgetary estimates. The Company is currently evaluating vendors and platforms through a competitive bidding process. The Company will update the estimate when the competitive solicitation process is complete.

1.3.2 INCREMENTAL O&M SPENDING (ACTUAL V. PLANNED SPENDING)

The table below summarizes the incremental O&M spending identified in the plan compared to the actual and forecast spending. The Company did not incur any incremental O&M spending in 2018. At this point the Company has not identified changes to the proposed incremental O&M spending. The Company will update this estimate of incremental O&M spending as it details those costs during the project design phase (i.e. incremental software licensing fees, incremental staffing requirements, and incremental maintenance activities).

	Actual/Forecasted Incremental O&M Spending			
	2017	2018	2019	2020
Monitoring and Control				
SCADA				
Original Plan Spending	$ -	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ -	$ -
OMS Integration with AMI				
Original Plan Spending	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Actual/Forecast Spending	$ -	$ -	$ -	$ 1,000
Volt VAr Optimization				
VVO				
Original Plan Spending	$ -	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ -	$ -
Advanced Distribution Management System				
ADMS				
Original Plan Spending	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Actual/Forecast Spending	$ -	$ -	$ -	$ 100,000
DERMS				
Original Plan Spending	$ -	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ -	$ -
Field Area Network				
Field Area Network				
Original Plan Spending	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Actual/Forecast Spending	$ -	$ -	$ 100,000	$ 100,000
Workforce Management				
Mobile Platform Damage Assessment				
Original Plan Spending	$ -	$ -	$ -	$ -
Actual/Forecast Spending	$ -	$ -	$ -	$ -
Total				
Total				
Original Plan Spending	$ 201,000	$ 201,000	$ 201,000	$ 201,000
Actual/Forecast Spending	$ -	$ -	$ 101,000	$ 201,000

Table 2 – Planned Versus Actual Incremental O&M Spending

2 PROGRAM IMPLEMENTATION OVERVIEW

The Company has developed an organizational structure, project management and project approval and tracking process that rely mostly on existing employees and processes. The Company believes this approach will help the Company to manage costs and result in an efficient implementation of the grid modernization investments. In some cases, when the Company does not have the experience or technical expertise, external resources may be required to assist with the design and implementation of GMP investments

2.1 ORGANIZATIONAL CHANGES TO SUPPORT PROGRAM IMPLEMENTATION

This section of the report 1) describes the organizational changes that the Company has implemented to manage the implementation of the GMP, 2) describes the cost and performance tracking measures adopted, and details the project approval process.

The Company implemented an organizational structure for grid modernization beginning at the highest level of the Company. The senior level sponsors of the GMP implementation include the Chief Executive Officer, Chief Financial Offer, and Senior Vice President External Affairs & Customer Relations. This group provides general oversight and direction for the GMP plan implementation. The senior level sponsors have assigned overall oversight of the grid modernization program to the Vice President of Engineering.

The Company developed a cross-functional Steering Committee to provide guidance and oversight of the GMP implementation process. The chair of the Steering Committee is the Vice President of Engineering. The Steering Committee includes representation from Engineering, Information Technology, Electric Operations, Regulatory, Customer Energy Solutions, Plant Accounting and Budgeting, Finance and Legal. The Steering Committee provides detailed oversight for budget and implementation of the GMP investments, reporting and annual updates.

The Steering Committee implemented project teams responsible for the detailed design and project implementation oversight. The Steering Committee identified individual project team leads for the GMP investments. The Steering Committee also developed teams related to the tariff revisions, performance metrics, evaluation plan, cost recovery filing and the Grid Mod Annual Report.

The initial focus of the project team leads was to identify members for each project team. Once the project teams were established, their efforts have been focused on reviewing the GMP investments to begin the scoping and detailed design of the projects.

2.2 COST AND PERFORMANCE TRACKING MEASURES ADOPTED

The Company decided that it would be most efficient to use the same budgeting and construction authorization approval process that is in use for all of its capital projects. GMP investments have been entered into the annual capital budget for review and approval. Each of the GMP investments will have its own construction authorization and/or its own CWO. The authorizations will follow the approval process described below.

Incremental O&M expenditures related to Grid Modernization will be budgeted and tracked through the Company's expense budget using established O&M budgeting procedures. In 2018, the Company did not have any incremental O&M expenditures.

2.3 PROJECT APPROVAL PROCESS

There are several layers of controls on spending. First, and perhaps most important, is the budget process. The capital budget represents the culmination of a lengthy planning process to identify and prioritize important needs, while ensuring that projects submitted for approval are the most cost effective solutions to address those needs and are estimated appropriately. The budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by senior management, and by the Company's Board of Directors.

After the budget is approved, each project within the budget must be further authorized before spending can occur. This is a second step in the approval process, and occurs on a project-by-project basis. A construction authorization must be prepared and submitted for approval for each planned expenditure and each project in the budget, even though the budget has already been approved. Each authorization must be fully approved prior to the commencement of any work, except where an unforeseen emergency occurs that requires the work to be completed to ensure public safety or restore service to customers, in which case the authorization can be completed immediately following the work.

Every capital project requires an approved construction authorization. The approval routing for each construction authorization includes, but is not limited to, the Plant Accountant, the Department Manager, the Vice President with functional responsibility for the project, and the Vice President of Engineering. Additional approvals may be required by one or more functional heads depending on the project and the functional areas affected by it. All authorizations over $50,000 also require the approval of the Assistant Controller. In addition, all authorizations exceeding $500,000 must be approved by the Controller and the Chief Financial Officer. Plant Accounting is responsible for assigning the appropriate routing for each authorization and for validating the authorization and construction work order ("CWO") number once all managers have approved the authorization, whereupon expenditures may begin.

Each project and each construction authorization is assigned a Project Supervisor. The Project Supervisor is designated on the authorization form as it is routed for approval, and is typically the person who developed the scope and cost of the project, and who initiated the construction authorization for approval. In all cases, the Project Supervisor is the person responsible for managing the project and the person directly accountable for controlling the scope and cost of the project.

Changes in the field sometimes result in changes to the scope of a project already approved and underway. When this occurs, the Project Supervisor is required to submit a revised construction authorization reflecting the then current (revised) scope, including cost, before proceeding further with the project. The revised authorization must be resubmitted for approval in the same manner as the original authorization, with the additional approval of the Controller and Chief Financial Officer. The revised authorization must include a detailed description identifying the change in scope and the reasons for the change, and provide a detailed cost breakdown.

The budget and authorization process recognizes that project estimates are just that, "estimates." Invariably, a small number of projects will overrun the original estimate due to conditions in the field, increases in material costs and other factors. The Project Supervisor's responsibility is to manage the cost of each project to the original authorized spending amount. If the cost of the project exceeds the authorized amount by 15 percent and $5,000, a supplemental authorization must be submitted that includes a detailed description of the reasons the project exceeded its authorized amount. The supplemental authorization must be resubmitted for approval in the same manner as the original authorization, with the additional approval of the Controller and Chief Financial Officer.

All projects, whether budgeted or unbudgeted, must be approved and authorized before spending can occur. If a non-budgeted expenditure is required, a non-budget authorization must be prepared and all necessary approvals received. It is the responsibility of the applicable budget manager to ensure that non-budgeted expenditures are required to ensure a safe and reliable system for our customers. Non-budget authorizations must be submitted for approval in the same manner as the project would normally be authorized, with the additional approval of the Controller and Chief Financial Officer.

O&M expenditures also require approval prior to spending. The O&M budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by senior management, and by the Company's Board of Directors. Expenditures are tracked on a monthly basis. Each level of management has varying approval levels. Deviations from the budgeted amount require additional reporting and explanation. Grid Modernization expenditures will be tracked separately to ensure the costs are incremental in nature.

3 IMPLEMENTATION BY INVESTMENT CATEGORY

This section of the report provides details for each GMP investment category at both the system and feeder level. In some cases, the investment is not implemented differently at the system as opposed to the individual feeder level. For instance, some software projects are implemented across the service territory at the same time and not on an individual feeder basis. The investment categories and project investments are identified in Table 3 below:

Investment Category	**GMP Investment**
Monitoring and Control	Supervisory Control and Data Acquisition
	OMS Integration with AMI
Volt/VAr Optimization	VVO Automated LTC VVO Automated Voltage Regulators VVO Capacitor Banks
Advanced Distribution Management System	ADMS
	DERMS
Communications	Field Area Network
Workforce Management	Mobile Platform Damage Assessment

Table 3 – GMP Investments by Investment Category

3.1 SYSTEM LEVEL NARRATIVE BY INVESTMENT CATEGORY

This section of the report identifies the progress made at the system level for each of the investment categories: it describes the project; provides a description of the work completed lessons learned, challenges and successes; provides actual versus planned implementation and spending; describes the performance of the implementation and deployment; describes the benefits realized as a result of the implementation; describes the capability improvement; provides key milestones; and provides updated projections for the remainder of the three year term.

Some of the projects in the GMP are closely tied together. For instance, a VVO system will not be successful without a FAN or ADMS. The Company is coordinating the projects in Table 4 below so they can be implemented on the same portions of the system at the same time.

Investment Category	**GMP Investment**
Monitoring and Control	Supervisory Control and Data Acquisition
Volt/VAr Optimization	VVO Automated LTC VVO Automated Voltage Regulators VVO Capacitor Banks
Advanced Distribution Management System	ADMS
Communications	Field Area Network

Table 4 – GMP Project Schedules to be Coordinated

The Company's plan is to implement these projects on a substation by substation basis. For instance, the FAN, VVO, SCADA and ADMS projects would be implemented at the same time or close proximity to each other. In order to facilitate this effort, the Company developed a ranking system to prioritize which substations provide the largest benefits to customers and should be completed first.

The Company developed a prioritization model shown in Table 5 below using a weighted ranking system based upon the following items:

Weighting Factor	Measurement Category	Description
30%	Peak Demand	The VVO project provides the largest benefit to customers. In order to get the greatest benefit as soon as possible, the VVO system should be implemented on the circuits with the highest peak demand.
30%	Percent Substation Loading	This is a measure of the peak loading on a substation as compared to its rating. For instance, a substation that is reaching its rating may require a system improvement to alleviate the loading concern. The VVO project provides the opportunity to reduce peak demand and potentially defer investment in a system improvement.
20%	Number of Customers	This is a combined measure of reliability and customers gaining the benefit of Grid Mod investments. The substations serving the largest number of customers will allow more customers to begin receiving benefits of the GMP investments.
10%	Planning Level Voltage Concerns	Distribution planning is used to identify portions of the distribution system which may be approaching voltage limits as defined in planning guidelines. The VVO project would provide the opportunity to control the voltage and alleviate loading and potentially defer investment in a system improvement.
10%	Existing SCADA	In areas that already have distribution SCADA or may only need small modifications to achieve the required functionality may allow other functionality to be implemented more quickly.

Table 5 – Weighted Rankings for Prioritization Model

The Company's prioritized ranking system weighs the ability to reduce load evenly with the opportunity to defer system investments. These two aspects provide the largest potential monetizable benefits to customers. In comparison, the Company weighs the opportunity to reach as many customers as possible slightly less than the first two. This is still a very important aspect, but may not provide the largest benefit. Implementing a project in an area that serves a larger number of customers but does not experience loading concerns may not maximize the benefits. The Company ranks the last two factors evenly, as they both provide benefit to customers and should be included in the ranking system.

In each of the measurement categories, the highest weighted substation receives a score of 1. For instance, the substation serving the most customers receives a score of one (1) and the other substations are given a score that is proportionate to the maximum number[1]. This is repeated for each category. The score for each category is multiplied by the weighting factor and added together to give a total score for each substation. The substation with this highest score becomes the highest priority for implementing the projects. Table 6 provides the results of the calculations. The substations have been ordered from highest to lowest rank.

Substation	Number of Customers	Planning Level Voltage Concerns	Existing SCADA	Peak Demand	Percent Substation Loading	Rank
Townsend	0.43	0.64	1.00	0.58	1.00	0.72
Lunenburg	0.60	0.94	0.50	0.48	0.85	0.66
Summer St.	0.76	0.71	0.43	0.76	0.53	0.65
W. Townsend	0.68	1.00	0.50	0.44	0.78	0.65
Beech St.	1.00	0.79	0.13	0.62	0.51	0.63
Pleasant St.	0.77	0.74	0.50	0.45	0.68	0.62
Princeton Rd.	0.21	0.63	0.38	1.00	0.46	0.58
Sawyer Passway	0.55	0.27	0.34	0.52	0.24	0.40
Canton St.	0.59	0.30	0.00	0.34	0.46	0.39
River St.	0.37	0.39	0.38	0.23	0.30	0.31
Nockege	0.24	0.74	0.00	0.11	0.49	0.30

Table 6 –Prioritization Model Scores

3.1.1 MONITORING/CONTROL

The Monitoring and Control investment category includes two projects fromr the Company's GMP. The first project is to expand the coverage and functionality of Company's SCADA system. The second project is to further integrate OMS with the Company's AMI system.

3.1.1.1 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

The objective of this project is to implement key SCADA functionality at all of the Company's substations. SCADA provides for the remote monitoring of conditions on the electric system and the remote control of equipment and functions by operating personnel or automation

[1] For instance, if Substation A serves the greatest number of customers (i.e. 5,000 customers), Substation A would receive a score of 1. If Substation B serves 2,500 customers, Substation B would receive a score of 0.5.

systems. The substation SCADA project is a component of the Company's Monitoring and Control program as part of its overall GMP, and is an enabling technology for other projects in the GMP including VVO and ADMS. In conjunction with other components of the Plan, it will support the GMP objectives of reducing the effects of outages and optimizing demand.

The implementation of SCADA at a substation typically involves the installation of a SCADA terminal unit at the site, the interconnection of the terminal unit with local devices and sensors, the establishment of communications between the terminal unit and the remotely-located SCADA Master system, and the associated programming to implement the desired SCADA functions.

Presently, SCADA is already implemented to some extent at some of the Company's substations, and not at all at others. Furthermore, at many substations that presently have some level of existing SCADA capability, it is incomplete to the extent intended under the GMP. Therefore, this project will add SCADA at those substations that do not presently have it, and expand SCADA capabilities at other substations where the functionality may be incomplete.

Finally, some of the substation devices that will be necessary to provide the needed power system measurements or that will otherwise be put under SCADA control are either absent or not suitable for this purpose (e.g. hydraulic reclosers, obsolete controls, etc.). Therefore, this SCADA project will also drive the replacement of that type of equipment and the installation of additional ancillary devices to better facilitate SCADA deployment.

3.1.1.1.1 Description of Work Completed

Prior to the Order, SCADA had already been implemented to some extent at a few of the Company's substations. During the intervening years between the submission of the Company's GMP in August 2015 and the issuance of the Order in May 2018 approving this portion of the plan, SCADA capabilities had been deployed to some extent at some additional substations.

This includes SCADA implementations of various extents at six (6) substations, with five (5) completed in 2018 and one presently in progress with plans for completion in 2020. However, as these projects were already underway when the GMP Order was issued, and as described in the Order, their associated costs are not eligible to be included in the GMRF.

3.1.1.1.2 Lessons Learned/Challenges and Successes

Further detailed design and SCADA functionality review identified certain equipment replacements and device additions which were not identified in the original GMP estimate. The replacements represent an increase in the overall cost proposals for the SCADA project. These replacements and additions are necessary to achieve the levels of functionality and measurement requirements now established for the other grid modernization projects and metrics. A detailed project plan including schedule and estimate has been provided below.

3.1.1.1.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

The Table 7 below demonstrates the actual versus planned implementation and spending. The Original Plan Estimate is the estimate that was filed with the Company's GMP in 2015. The Revised Plan Estimate is the Company's most recent estimate of what the project is expected to cost in the identified years based upon the most up to date information.

	Overall Project Estimate Through 2020			
SCADA	2017	2018	2019	2020
Original Plan	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Revised Plan	$ -	$ -	$ 720,000	$ 135,000

Table 7 – SCADA Spending Estimates

The Company has taken the time to re-evaluate the SCADA deployment plan and align it with the prioritization model described earlier in this document. This evaluation and detailed design has allowed the company to make a more detailed estimate of the overall SCADA deployment.

The original plan for SCADA and the VVO Automated LTCs, resulted in a levelized 10 year plan with an annual estimate of $164,000 per year or $1.64 million total. The new estimate totaling approximately $2.43 million shown in Table 8 identifies the cost estimates to install SCADA and add VVO automation to the substation LTCs at each substation.

	Cost Estimates by Substation at Planned Years of Completion[2]						
Substation	2018	2019	2020	2021	2022	2023	2024
Beech Street	$ 0		$ 80,000				
Canton Street					$ 640,000		
Lunenburg	$ 0		$ 55,000				
Nockege							$ 700,000
Pleasant Street	$ 0						
Princeton Road	$ 0			$ 45,000			
Rindge Road		$ 45,000					
River Street						$ 190,000	
Sawyer Passway							
Summer Street			$ 0				
Townsend		$ 675,000					
Wallace Road		$ 0					
West Townsend	$ 0						

Table 8 – SCADA Schedule and Cost Estimate

[2] Some sites are listed with multiple years of activity due to separated SCADA implementation efforts. Entries in the amount of $0 indicate SCADA implementations made (or underway), but not included in the GMRF.

The overall cost increase is primarily due to 1) replacement of certain devices within the substations in order to gain the SCADA capability and functionality required for grid modernization and 2) the cost of materials and labor has increased from the time of the Company's initial GMP filing. Project costs identified as $0 indicate work is being completed but will not be included in GMP (e.g. funded for DER customer installation).

The estimated annual spending for this plan is not as levelized as was conceived in the original GMP. This is due to the varying extent of SCADA implementation already existing at some substations, and the varying amount of replacements of related equipment and additions of ancillary devices.

Conversely, the overall timeframe to complete this SCADA implementation across all FG&E substations is anticipated to be completed in a shorter timeframe than in the original GMP, as a result of ongoing SCADA deployment that has occurred for other purposes during the intervening years since the GMP was developed.

3.1.1.1.4 Performance on Implementation/Deployment

The new schedule provided in the table above identifies that the SCADA implementation including the additional scope of equipment replacements will be completed in seven years as opposed to ten years. This improvement in timeframe is primarily due to the Company's continued installation of SCADA functionality between the GMP filing and the resulting order.

3.1.1.1.5 Description of Benefits Realized as the Result of Implementation

Once the SCADA projects are complete at each substation, the GMP estimates that the company will be able to save 10 minutes off of each whole-circuit outage. The Evaluation plan will be designed to quantify the benefit.

3.1.1.1.6 Description of Capability Improvement

When the SCADA deployment is complete at each substation the following functionality is expected to be present:

- Real time telemetry and historical interval data for the following measurements for each power transformer and circuit position:
    - Voltage
    - Current
    - Active and Reactive Power
    - Active and Reactive Energy
- Remote monitoring of substation bus status (live/dead)
- Remote monitoring and control of substation circuit breakers/reclosers
- Remote monitoring and control of substation transformer LTCs and bus regulators
- Remote monitoring and control of substation capacitor banks
- Ability to integrate with ADMS and VVO

3.1.1.1.7 Key Milestones

As shown in the table above, full SCADA implementation for the GMP is planned to be completed for Townsend, Wallace Road and Rindge Road substations in 2019, and Beech Street, Lunenburg and Summer Street substations in 2020.

3.1.1.1.8 Updated Projections for Remainder of the Three-year Term

The updated projections are shown in the table above. The increase in estimated cost associated with this project is related to 1) updated labor estimates between the 2015 and 2019 estimates; and 2) increase in scope to replace equipment that is not compatible with SCADA.

3.1.1.2 OMS INTEGRATION WITH AMI

The Company's AMI system provides information on outages for every meter on the system. This project is designed to improve the integration of outage information from meters into the OMS outage prediction engine, thereby improving the outage prediction process, reducing false positives and improving the ability to identify the location of nested outages.

The Company is developing a piece of configurable "middleware" (i.e., software) to analyze AMI status changes along with additional relevant data points, and computing an "AMI Confidence Score" for AMI based customer outage reporting. Based on the configuration of the middleware, suspected outages above the allowed "score threshold" will be treated as "real outages" and reported to OMS as such. Those that fall below the threshold will be logged and sent to OMS for view only.

The system will leverage a set of correlating data inputs such as historical outages, low level signal data, and weather data along with machine learning models to assist in computing outage confidence.

3.1.1.2.1 Description of Work Completed

This project is still in the initial stages. In 2018, the Company worked closely with our AMI vendor (Landis & Gyr) to identify a combination of data points available on the meter and the AMI collectors along with various correlating data points (environmental and coincident) to build a model that can accurately confirm suspected outages and electronically qualify them.

The Company is researching machine learning tools, data science techniques, and cloud technologies to determine the best approach for building middleware applications that will help to determine and calculate the confidence score.

3.1.1.2.2 Lessons Learned/Challenges and Successes

The Company's AMI system has the ability to detect and report outages based upon status changes that occur to meters in the field. Using Landis & Gyr's Gridstream communication architecture, the AMI Command Center software continuously monitors and communicates with these meters watching for changes in status. These status change events are reported to the

Company's OMS via a Web Services integration point. At present, out of the box, our AMI system does not have the intelligence to distinguish between communication problems that do not result in an actual customer outage (noisy power line, for example) versus those events that result in an outage. As a result, we are not able to trust the data (at face value) enough to allow for a direct outage report in our OMS system. Presently, the data is integrated in a "view only" layer in the OMS user interface and is used only as an aid to assist in determining the scope of an outage.

3.1.1.2.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

Table 9 below demonstrates the actual versus planned implementation and spending. The Original Plan Estimate is the estimate that was filed with the Company's GMP in 2015. The Revised Plan Estimate is the Company's most recent estimate of what the project is expected to cost based upon the most up to date information.

	Project Estimate			
OMS Integration with AMI	2017	2018	2019	2020
Original Plan Estimate	$ 52,000	$ -	$ -	$ -
Revised Plan Estimate	$ -	$ -	$ 70,000	$ 35,000

Table 9 – OMS Integration with AMI Spending Estimates

The increase in estimated costs associated with this project are related to: 1) the cost of materials and labor has increased from the time of the Company's initial GMP filing; 2) vendor involvement has increased over original estimates; and 3) additional development time associated with the cloud based solution.

3.1.1.2.4 Performance on Implementation/Deployment

This integration is still in the development stage. Information on performance will be provided when the system goes live.

3.1.1.2.5 Description of Benefits Realized as the Result of Implementation

The Company has not realized the benefits identified as part of the GMP because this project is not yet complete. The theory is that the outage information from the AMI system will allow the Company to know about the outage without having to rely on a customer phone call through the IVR system. It is expected that the AMI system on average will be five (5) minutes faster than customer calls. This will be measured using data from the OMS system following deployment.

3.1.1.2.6 Description of Capability Improvement

The proposed upgrade will allow AMI outage information to be used directly in the AMI outage prediction engine for outage reporting if the AMI status change has an associated high confidence factor. This AMI information should improve timeliness of outage detection, dispatch, extent and restoration.

3.1.1.2.7 Key Milestones

In 2019 and 2020 the plan is to continue to work with the Company's AMI vendor to determine applicable data points to include in outage confidence score calculation and design the statistical model to document and validate the approach. Next, a middleware application will be developed and deployed to calculate outage confidence scores. The system will be tested for accuracy and completeness prior to integrating with the live OMS system.

3.1.1.2.8 Updated Projections for Remainder of the Three-year Term

The updated projections are shown in Table 9 above. The increase in estimated cost associated with this project is related to 1) updated labor costs between the original estimate and revised estimate; 2) vendor involvement has increased over original estimates and 3) additional development time associated with the cloud based solution.

3.1.2 DISTRIBUTION AUTOMATION (DA)

When the Company filed its original GMP in August 2015, the Plan focused on implementing enabling technology such as a FAN, SCADA and ADMS before contemplating implementation of DA projects. As such, the Company's plan does not have any DA projects identified for automatic sectionalizing and restoration of faulted portions of a circuit.

3.1.3 VOLT/VAR OPTIMIZATION (VVO)

Volt VAr Optimization (VVO) is a proven means for utilities to save energy for customers and reduce system demand all while ensuring reliable service. It also can help integrate DERs, by controlling the voltage variations caused by DERs. The VVO project will deliver significant and measurable benefits for the Company and its customers, while creating platform capability to be leveraged in the future.

The scope of the project includes installing automated controls on all voltage and reactive power equipment on all distribution circuits. This includes controls of all capacitor banks, voltage regulators and transformer load tap changers (LTCs). In addition, voltage and energy monitors will also be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized by a central system (potentially ADMS or another software based system). The communication between the ADMS and the VVO controls will be designed and installed as part of the FAN project. The design requirements of the VVO system will be coordinated with the plans of the ADMS and the FAN.

3.1.3.1.1 Description of Work Completed

The Company has assigned an internal project manager and assembled a project team of internal employees to evaluate and implement a VVO system. Because the VVO system is integrated with the ADMS and likely monitored and controlled through the SCADA system with communication media installed as part of the FAN, the VVO team is coordinating its efforts closely with these other project teams. This team is in the process of developing the VVO project scope and detailed project schedule.

The Company has purchased a software package (Cyme) to assist in the circuit modeling and analysis of expected VVO results. The engineering analysis software has the ability to model the impact of VVO on a feeder level basis. The year-to-year plan with locations and types of controls to be installed on each distribution circuit has also been determined. The Company plans to incorporate the installation of controls one substation per year, detailed below.

3.1.3.1.2 Lessons Learned/Challenges and Successes

The Company has hosted many working meetings and demonstrations with various vendors to understand the different ways to implement a VVO system. The Company is evaluating two basic approaches to implementing a VVO system: model based and measurement based.

In a model based system, the system utilizes a dynamic operating model of the system in conjunction with real time information from the field and runs this information through a complex optimization algorithm, within an ADMS, to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit. The benefit to this approach is that fewer field devices are required since the algorithm relies heavily on the model.

In a measurement based system, the VVO algorithm relies on verified field measurements from voltage sensors, regulator controls, LTC controls and capacitor banks to provide the VVO algorithm with the information it needs to take the appropriate action. The benefit to this approach is that real time measurements are being used instead of relying on the accuracy of a computer model.

In either approach, the Company is evaluating the integration of the VVO system with the ADMS to provide one central control system that our operators will use.

3.1.3.1.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

Table 10 below demonstrates the actual versus planned implementation and spending. At this time the Company is expecting to install the required controls on all existing voltage regulators, transformer LTC's, and capacitor banks. VVO functionality will be implemented on all distribution circuits as proposed in its GMP. The Company is still evaluating the accuracy of its project estimates and may revise project estimates once the Company has a more detailed design.

	Project Estimate			
VVO	2017	2018	2019	2020
Original Plan	$ 739,000	$ 739,000	$ 739,000	$ 739,000
Revised Plan	$ -	$ -	$ 739,000	$ 739,000

Table 10 – VVO Spending Estimates

3.1.3.1.4 Performance on Implementation/Deployment

This project is just getting started in 2019. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

3.1.3.1.5 Description of Benefits Realized as the Result of Implementation

The VVO system operates by constantly trying to optimize voltage regulation (voltage regulators, LTCs and reactive compensation through switched capacitor banks). The VVO project is expected to reduce customer energy consumption by 2% and is expected to reduce system and circuit peak demand by a similar amount. This will directly benefit customers by reducing their electricity consumption and threby reducing their bills.

3.1.3.1.6 Description of Capability Improvement

There are three primary aspects to implementing a VVO program: communications, software intelligence and field equipment. A robust communications network is the foundation for a successful VVO program. The communications network described earlier in this report will be designed to support the VVO program. The software intelligence will be discussed as part of the ADMS project.

Voltage regulation refers to the management of circuit level voltage in response to the varying load conditions. There are two primary devices required to control the voltage on a distribution circuit: transformer LTCs and voltage regulators. The distribution management system uses input from voltage sensors across the system to adjust the voltage regulators and LTCs to provide power within an appropriate voltage limit. Capacitors are used for reactive power (VAr) regulation.

Although the project does not presently include plans to control customer owned inverters, the Company plans to implement a system with the possibility of controlling inverters along with capacitors, to provide reactive power to the distribution system.

3.1.3.1.7 Key Milestones

The Company has identified the field controls that will need to be replaced in order to implement a VVO system and has developed the following replacement plan in line with the prioritized model that is described above.

Year	Substation	LTC Controls	Volt Reg Controls	Cap Bank Controls	3-Phase Monitors	1-Phase Monitors
2019	Townsend	1	1	5	2	6
2020	Lunenburg	3	7	2	3	4
2021	Summer St	1	10	6	4	7
2022	West Townsend	1	4	4	1	4
2023	Beech St	1	0	3	4	1
2024	Pleasant St	1	0	6	5	3
2025	Princeton Rd	2	0	2	2	1
2026	Sawyer Passway	2	0	4	1	4
2027	Canton St.	2	0	5	5	2
2028	River St.	1	4	3	3	3
2029	Nockege	1	8	1	1	5
2030	Rindge Rd	0	7	0	1	1

Note: Rindge Road is a distribution circuit that taps off of another distribution circuit.

Table 11 – VVO Field Equipment Estimates

3.1.3.1.8 Updated Projections for Remainder of the Three-year Term

In 2019-2020, the Company plans to:

- Continue with the evaluation process to determine if a model based system or a measurement based system makes the most sense with the goal of selecting an approach and vendor by the end of 2019;
- Model the distribution circuits in Cyme in the order of VVO control installation; and
- Implement control replacement projects as identified in the table above.

3.1.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

The ADMS investment category includes two projects for the Company's GMP. The first project is an ADMS project to allow for more advanced measurement and control of the distribution system. The second project is to implement a Distributed Energy Resource Management System (DERMS) which will enable the Company to improve situational awareness and operational intelligence for DERs.

3.1.4.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

This project consists of implement an ADMS and integrating the system the Company's existing GIS, OMS and SCADA systems. The ADMS will support VVO, CVR, power flow analysis, distribution system automation, including automated distribution switching and fault location, isolation and service restoration (FLISR). The ADMS will also serve as a platform for more advanced modules in the future such as a DERMS.

An ADMS is the next step in the evolution of distribution management systems. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, circuit analysis, load flow, and SCADA systems together to provide all of the information to one location. An ADMS allows its users, operators, and dispatchers a real-time view of the distribution system. In order for the ADMS to provide benefits, it must be integrated with the some of the Company's other Grid Modernization initiatives including, the FAN, Substation SCADA and VVO projects.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, network configuration, and VVO.

As provided in the Company's GMP, the implementation of ADMS is primarily focused on integration of a VVO system.

3.1.4.1.1 Description of Work Completed

The Company's GMP did not contemplate work on the ADMS project until the third year of the plan. However, the Company has assigned an internal project manager and assembled a project team of internal employees. The team has hosted multiple vendor demonstrations to educate the group on the functionality that an ADMS can provide. This information will assist the team to finalize the scope and schedule of the ADMS project. The team is also developing a detailed RFP for the procurement and implementation of an ADMS.

3.1.4.1.2 Lessons Learned/Challenges and Successes

Similar to the VVO project, the Company has hosted many working meetings with various vendors to understand the different ways to implement an ADMS system. The Company is evaluating two basic approaches to implementing an ADMS system: model based and measurement based.

In a model based system, the system utilizes dynamic operating model of the system in conjunction with real time information from the field and runs this information through a complex optimization algorithm, within the ADMS, to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit. The benefit to this approach is that fewer field devices are required since the algorithm relies heavily on the model.

In a measurement based system, the ADMS relies on verified field measurements to provide the ADMS with the information it needs to take the appropriate action. The benefit to this approach is that real time measurements are being used instead of relying on the accuracy of a computer model.

In addition, the Company will need to integrate existing systems (GIS, OMS, CIS, and SCADA) with the ADMS.

3.1.4.1.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

The Company's plan did not contemplate spending within the first two years of the plan. However, the Company is currently evaluating different ADMS systems with the goal of selecting a vendor by the end of 2019. The Company is currently developing a detailed RFP which will be used to inform and updated project estimate and schedule. The Company will present a revised estimate and project plan when the RFP process has been completed.

	Project Estimate			
ADMS	2017	2018	2019	2020
Original Plan	$ -	$ -	$ 700,000	$ 700,000
Revised Plan	$ -	$ -	$ -	$ 700,000

Table 12 – ADMS Spending Estimates

3.1.4.1.4 Performance on Implementation/Deployment

This project is just getting underway in 2019. The Company's ADMS project team is currently in the process of evaluating the capabilities of various ADMS products and will develop a detail implementation scope and plan based of this evaluation. Information on performance will be provided once the system is implemented. At this time Unitil is expecting the ADMS implementation to be in-line with what was proposed in its GMP.

3.1.4.1.5 Description of Benefits Realized as the Result of Implementation

The ADMS will enable VVO and reduce customer energy consumption by 2% and is expected to reduce peak demand on the individual feeder and substation by a similar amount. This will directly benefit customers by reducing their electricity bills. The ADMS will also enable better voltage control for the integration of DER and improve reliability through the implementation of FLISR. The ADMS will serve as a platform for more advanced modules such as a DERMS.

3.1.4.1.6 Description of Capability Improvement

The following functionalities are being evaluated as part of the ADMS project:

- GIS editor to transfer the network model from the GIS system to the ADMS system on a routine basis as changes to the network topology are made in GIS
- Verification of network connectivity
- Integration with existing OMS, CIS and SCADA systems
- Switching manager and simulation module
- VVO optimization
- FLISR
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training

The proposal evaluation process will also include the evaluation of impacts and modifications to existing systems that ADMS may require. The Company plans to allow vendors to propose alternatives that may require the transition to new SCADA and/or OMS systems. These alternatives will be incorporated into the evaluation scoring model. In addition, The Company will be evaluating and determining if any modifications are required to its existing GIS system from an information or configuration standpoint to allow for a more robust ADMS product.

3.1.4.1.7 Key Milestones

The Company has hosted multiple working meetings with vendors with the objective to identify and evaluate available ADMS functionality. This information will be used to determine what functionality the Company plans to implement and assist in the development of the RFP. (Q3 2018 – Q2 2019)

The Company will develop a detail RFP for the procurement and implementation of an ADMS. This proposal will be sent to multiple vendors. (Issue RFP to vendors late summer/early fall 2019).

The Company will develop a scoring model that will be used to evaluate proposals and invite the top two or three vendors to provide a detailed presentation of their system, which would allow the Company to perform a more detailed product review and address any questions. The evaluation scoring model for the vendor's presenting will be modified based on the results of the presentations and answers to the company's questions. (Q2 – Q4 2019)

The winning vendor will be selected based on final evaluation scores and other qualitative benefits. (Vendor selection by the end of 2019)

3.1.4.1.8 Updated Projections for Remainder of the Three-year Term

The Company will work with the selected vendor to finalize project scope, schedule and estimated cost. Implementation is expected to begin in 2020 with full integration of existing systems (GIS, CIS, OMS, SCADA, etc.) and equipment by the third quarter of 2022. This also includes the implementation of VVO on circuits that have controls and sensors capable of VVO.

FLISR will be reviewed as part of the evaluation process and may be implemented in the future when the Company installs distribution automation schemes.

At this time the Company is evaluating the possibility of expanding the scope of the ADMS project in 2023-2029 to include additional functionality, such as FLISR or loss optimization if the benefits outweigh the cost of implementation. This added functionality would likely require the installation of additional fully automated field devices and sensors.

3.1.4.2 DER ANALYTICS AND VISUALIZATION (DERMS)

This project is to implement DERMS functionality to monitor and manage/control DERs across the service territory. This technology could be implemented as a module to work with an ADMS or as a stand-alone system. The technology will improve situational awareness and operational intelligence for this increasingly important resource. DERMS will be used by grid operators and engineers for efficient grid operations and planning.

The Company's filed GMP does not contemplate the DERMS project to be implemented until the fifth year of the plan. The Company is evaluating the ADMS systems with respect to its ability to implement DERMS functionality in the future. The Company has set a priority on implementing ADMS, SCADA and VVO prior to spending some time on integrating DERMS. The Company will report on further progress in future annual reports.

3.1.5 COMMUNICATIONS

The Company currently uses a powerline carrier AMI system, and a combination of wireless (cellular) and land-line telecommunications services for the existing SCADA communications. The Company does not have a FAN installed that is capable of supporting the capability and functionality identified as part of the plan.

3.1.5.1 FIELD AREA NETWORK

This project consists of installing a FAN, including communications between collectors and endpoint devices (meters and distribution devices), and backhaul communications from collectors at each substation to the central office. In the context of the modern grid, communications is the glue that makes it possible for all parties to interact and share information. The FAN will handle data traffic between distribution and grid edge devices and centralized information and operational systems. The FAN will be used by most of the modern grid systems that the Company implements. These will include advanced metering and TVR, distribution automation and DER management.

3.1.5.1.1 Description of Work Completed

The Company worked with engineering consultants and communication vendors to review technical alternatives and develop an estimate for its service territory. This estimate was not based upon detailed engineering analysis or design. The Company contemplated completing a detailed engineering evaluation and design prior to implementing a project.

The Company does not have communication expertise on staff with the ability to evaluate the requirements and design a FAN for the service territory. A specification was developed to request proposals (RFP) from vendors for field area network consulting services. The RFP seeks to retain a consultant to assist in the specification and evaluation of proposals for a FAN throughout its electric service franchise area in Massachusetts. The goals of this proposal will be to assist the Company with identifying the needs and requirement of the FAN, developing a specification for the network, creating a list of appropriate bidders and evaluating proposals.

The RFP was sent to twelve different vendors who the Company believed have the knowledge and capability to perform these services for the Company. The Company received eight detailed proposals.

The Company developed a weighted decision matrix to evaluate the various proposals. The decision matrix evaluated each of the proposals on:

- Meets Requirements - Bidder appears to comprehend the RFP, and their proposals appear to satisfy the requirements (pending reasonable accommodations for any stated exceptions).
- Experience/Qualifications - Bidder appears to be qualified, competent and experienced in providing the services requested.
- Schedule - Bidder has expressed their ability to meet schedule.
- Value - The anticipated range and quality of proposed deliverables from the Bidder, the anticipated working relationship between Unitil and the Bidder, and the anticipated effort on Unitil's part appears to represent a good return relative to the Bidder's proposed pricing.

The FAN project team evaluated each of the proposals and filled out the evaluation matrix. The top vendors were invited into the Company to provide a presentation and allow for the project team to ask more questions. The project team adjusted their scores in the evaluation matrix following the information from the presentations. The Company selected a vendor at the end of 2018.

The FAN project team and the vendor are in the initial stages of evaluation and study.

3.1.5.1.2 Lessons Learned/Challenges and Successes

The Company had originally developed separate project teams for each grid modernization investment. Throughout the early stages of the process, the Company has learned that each of the investments are so closely tied together that guidance on project rollout needed to be provided to each group.

As described in the VVO section, the Company developed a prioritization model to identify how the investments should be implemented to provide the greatest benefit. At the present time, it is expected that the FAN will follow in a similar manner.

3.1.5.1.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

The Company's plan estimated a level funded project over the 10 year GMP timeframe. It is now expected that the project costs will not be quite as levelized as previously expected. The Company is taking the time to complete a detailed study and evaluation to develop a more detailed project scope, schedule and costs, and align it with the prioritization model described earlier in this document. The Company will present a revised estimate and project plan when the RFP process has been completed.

	Project Estimate			
Field Area Network	2017	2018	2019	2020
Original Plan	$ 280,000	$ 280,000	$ 280,000	$ 280,000
Revised Plan	$ -	$ -	$ 280,000	$ 280,000

Table 13 – FAN Spending Estimates

3.1.5.1.4 Performance on Implementation/Deployment

The project is just getting started in 2019. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

3.1.5.1.5 Description of Benefits Realized as the Result of Implementation

A FAN is an enabling technology that would provide the Company with the communications backbone to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other programs does not result in any monetizable benefits. However, the VVO system cannot provide the benefits identified without a FAN.

3.1.5.1.6 Description of Capability Improvement

In the context of the modern grid, communications is a foundational technology that makes it possible for systems, operators and stakeholders to interact and share information. The FAN will handle data traffic between distribution, grid edge devices, centralized information and operational systems. The FAN will be used by most of the modern grid systems to be implemented.

3.1.5.1.7 Key Milestones

Key milestones for this project will be identified during the initial study process.

3.1.5.1.8 Updated Projections for Remainder of the Three-year Term

The Company is currently working with the consultant on a FAN evaluation. It is expected that this study will occur during 2019 and the implementation of a FAN will begin in 2020. More information on the scope, schedule and cost will be provided in future annual reports.

3.1.6 WORKFORCE MANAGEMENT

The Company's GMP includes a workforce and asset management program aimed to improve performance of the Company following major events. One project identified for the program includes a mobility platform for storm damage assessment that can integrate damage information with the OMS and work order process to improve situational awareness and the speed of restoration. This Mobile Platform Damage Assessment Tool will help the Company to make quicker, better-informed decisions and is aimed to ensure operational efficiency and maintain strong restoration performance.

3.1.6.1 MOBILE PLATFORM DAMAGE ASSESSMENT

This project is to implement a Mobile Platform Damage Assessment Tool to make quicker, better-informed decisions to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed. This would allow for a greater situational awareness.

3.1.6.1.1 Description of Work Completed

The Company has been researching and evaluating various applications that will expedite damage data acquisition, develop fasters ETR's, enhance overall situational awareness and produce more efficient work packages that will, in turn, expedite the overall restoration.

The project evaluation team is comprised of various company employees who have responsibilities either during routine or emergency times for processes and activities related to damage assessment and inspection. The evaluation team includes key members from the Electric Operations, Engineering, and IT departments as well as other employees who have emergency assignments related to Damage Assessment.

This group developed an RFP and received proposals from 13 vendors.

An initial screening process was used to separate the proposals into three tiers. Tier 1 vendors meet or exceed requirements set forth and have been contacted for a demo of their product. Tier 2 vendors may meet most of the requirements or require additional development but will still be considered. Tier 3 vendors either do not meet all requirements or have other constraints that may affect their ability to provide a suitable solution.

The evaluation criteria developed for this project and vendors consisted of a combination of many technical and operational requirements and features. Technical and security requirements for the application were provided by IT staff based on current requirements and restrictions while the Operational requirements were developed by key operational personnel familiar with the process. Each vendor meeting at least the minimum requirements will be considered for a series of product demonstrations. An evaluation model was developed to rank the vendors that were initially categorized in Tier 1. The following criteria were evaluated by the project team:

Technical Requirements
Solution is compatible with android, ios and windows operating systems
Solution has offline caching or other capabilities for loss of service
Solution is able to integrate with the desired applications for data (primary GIS and/or OMS)
Solution meets minimum requirements for data privacy and security
Solution has a separate testing and live portal capabilities
Bidder has provisions for ensuring the continuity of their solution and services (backup and data retention)
Solution complies with all access and permissions requirements (single sign on, user approvals)
Solution is cloud based leveraging major cloud based service

Operational Requirements
Bidder is able to provide 24/7 support services for solution including during emergencies/holidays
Solution is able to geo-fence/geo-tag incidents into groups
Solution has transactional history (audit logging) and can provide such reports
Field Collection - Solution has user-friendly field collection capabilities on mobile devices
Data Manipulation - Solution can analyze data (for ETRs), segment as required and be manually manipulated
Data Exportation - Solution can export specific data as needed to produce work packages and other assignments (i.e Environmental or Vegetation work)
Data Reporting - Solution can provide standard and ad hoc reports on information as required
User training - System should have a user-friendly interface requiring minimal training time
Dashboard view - Solution contains a dashboard style desktop user interface for back office use

General Bidder Qualifications
Bidder appears to be qualified, competent and experienced in providing the services requested.
Bidder has expressed their ability to meet schedule.
Bidder has experience with utilities and/or industry
Bidders pricing is competitive and is in line with project estimates and specifications

Table 14 – Mobile Platform Damage Assessment Evaluation Criteria

From this evaluation, several vendors were invited into the Company to provide a presentation on their proposal so that the project team could get questions to their answers. Following the vendor presentations, the evaluation matrix was updated.

At the present time, the project team is still working through the vendor selection process.

3.1.6.1.2 Lessons Learned/Challenges and Successes

Throughout this project, the Company has learned that mobile damage assessment is just one of the functionalities that these software platforms can provide. Other functionality includes asset management, inspections, and other workforce management tools. The Company is interested in additional functionality in the future and will evaluate the additional functionality available from the vendor offerings during the evaluation.

3.1.6.1.3 Actual vs. Planned Implementation and Spending, with Explanations for Deviation and Rationale

The project team has not developed an updated project estimate for this project. However, based upon the vendor pricing gathered up to this point, the estimated cost increase is approximately $100,000. The increase in cost is primarily due to the platform nature of the vendor products. The platform approach will provide the Company with the ability to implement future functionality if so desired (such as: mobile inspections, redline, asset management, etc.).

	Project Estimate			
Mobile Platform Damage Assessment	2017	2018	2019	2020
Original Plan	$ 300,000	$ -	$ -	$ -
Revised Plan	$ -	$ -	$ 300,000	$ 100,000

Table 15 – Mobile Platform Damage Assessment Spending Estimates

3.1.6.1.4 Performance on Implementation/Deployment

This project is just getting started in 2019. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

3.1.6.1.5 Description of Benefits Realized as the Result of Implementation

The application will have several benefits related to Operations and Planning including the ability to confirm, validate and document predicted devices leading to a greater accuracy of affected customer counts, outage causes and times of restoration. Field damage assessment information will also allow work orders to be tied to actual damage or repair work geographical areas and will also provide the company with faster field information to better estimate and identify the types and amounts of specific resources needed and better identify when resources will no longer be needed. The Plan estimated that this is expected to save on average 15 minutes per outage during a major event.

3.1.6.1.6 Description of Capability Improvement

The mobile platform damage assessment system will be an application based system that will replace the existing paper based damage assessment presently used by the Company. This system will allow damage to be collected on the mobile application including the location, the type of damage and pictures. This data will automatically transferred back to the head end system back in the office where ETRs and work packages can be developed, issued for repair, tracked and closed out.

The following capabilities are technical requirements for the mobile platform damage assessment application.

1. Data collected by the platform must be fully accessible via a documented application programming interface (API).
2. The platform must be capable of rendering output in a device agnostic, fully responsive manner, compatible with all major mobile, laptop and desktop devices
3. The platform must be capable of high availability, redundancy, high-capacity storage and industry standard security and compliance
4. The platform must have the ability to consume data from legacy applications
5. The platform must have documented APIs allowing the Company to build its own connectors
6. The platform must support direct integration with GIS
7. The platform must support the ability to capture, store and display rich media content such as photos, video and audio files.
8. The platform must support the ability to work offline / without real time connectivity to the internet
9. The platform must support offline mapping
10. The platform must support integration with Active Directory for Single Sign On
11. The platform must include the ability to capture GPS coordinates and geo tag records and collected assets with this data
12. The platform should have no cap on the number of applications or the number of records that can be collected by a given application
13. The platform must support, at a minimum, two discreet environments for testing and production
14. The platform must support electronic signature capture
15. The platform must include audit logging capabilities to capture transactional history
16. All Systems that Handle Confidential Information must encrypt the data that include Confidential Information in transit using algorithms and key lengths consistent with the most recent NIST guidelines.
17. The initial application built on this platform will be for Unitil's Damage Assessment system. However, there are a number of additional areas wherein real time information exchange would result in more effective work flows. Future applications may include (but are not limited to): Asset inspections, Mobile Workforce Management, Mobile Work Order Management and Outage Management

3.1.6.1.7 Key Milestones

The Company is currently in the midst of finalizing its evaluation period and reducing the amount of potential vendors based on the evaluation criteria. It is expected that the Company will select a vendor by the end of Q3 2019 and work throughout the remainder of 2019 and early in 2020 to develop and implement the solution.

3.1.6.1.8 Updated Projections for Remainder of the Three-year Term

The updated projections are shown in the table above. These projections will be refined once a vendor is selected. The increase in estimated costs associated with this project is related to 1) updated product costs between the original estimate and revised estimate; and 2) additional development time associated with integrations with existing systems.

3.2 FEEDER LEVEL NARRATIVE BY INVESTMENT CATEGORY

This section of the report will provide more detailed information, where applicable, demonstrating how the grid modernization investments and functionality has been deployed on a feeder or circuit level basis.

3.2.1 MONITORING/CONTROL

As previously described, the Monitoring and Control investment category includes two projects for the Company's GMP. The first is a project to expand the coverage and functionality of Company's SCADA system. This investment is implemented on a substation by substation and circuit by circuit basis.

The second project is to further integrate OMS with the Company's AMI system. This is a software project and is not implemented on a substation or circuit basis. When this project is complete, all meters on all circuits will be communicating information back to the OMS system.

3.2.1.1 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

As described above, the implementation of SCADA at a field site such as a substation typically involves the installation of a SCADA terminal unit at the site, the interconnection of the terminal unit with local devices and sensors, the establishment of communications between the terminal unit and the remotely-located SCADA Master system, and the associated programming to implement the desired SCADA functions. When SCADA is installed at the substation, it also includes installing SCADA on the circuit breaker or recloser (and any other equipment) feeding this circuit.

3.2.1.1.1 Highlights of Feeder Level Implementation

The table below identifies the status of SCADA on a substation and circuit basis.

Substation	Circuits	Comments
Beech St.	1W1 1W2 1W4 1W6	LTC control & partial SCADA completed 2018 (DG interconnection w/ full customer contribution) Full SCADA planned for 2020 as Grid Mod project; includes: (3) recloser controls, (1) meter
Canton St.	11W11 11H10 11H11	LTC controls & SCADA planned for 2022 as Grid Mod project includes: (3) reclosers, (2) LTC controls, (2) meters
Lunenburg	30W30 30W31	Partial SCADA completed 2018 (DA & DG interconnection projects) Full SCADA planned for 2020 as Grid Mod project; includes: (1) meter; no Regulator control replacements
Nockege	20H22 20H24	LTC control & SCADA planned for 2024 includes: (3) reclosers, (2) relaying packages, (1) LTC control, (1) meter
Pleasant St.	31W34 31W37 31W38	New LTC transformer & SCADA completed 2018 (Distribution Automation & Transformer Replacement projects)
Princeton Rd.	50W51 50W53 50W55 50W56	Partial SCADA completed 2018 (SCADA System Replacement project) LTC controls & full SCADA planned for 2021 as Grid Mod project
Rindge Rd.	35W36	SCADA to be completed in 2019 as Grid Mod project
River St.	25W27 25W28	Pre-existing partial SCADA - LTC control & full SCADA planned for 2023; includes: (2) recloser controls, (1) LTC control
Sawyer Pwy.	22W1 22W2 22W3 22W8 22W10 22W11 22W12 22W17	Pre-existing SCADA Possible future modifications for energy measurements for Grid Mod metrics
Summer St.	40W38 40W39 40W40 40W42	Pre-existing SCADA Full SCADA planned for 2020 (B123, 1303 and 1309 replacement project); no LTC control replacement
Townsend	15W15 15W16 15W17	LTC control & SCADA to be completed in 2019 as Grid Mod project includes: (3) reclosers, (1) LTC control, (1) meter
Wallace Rd.	1341	SCADA to be completed in 2019 (1341A & 1341B replacement)
W. Townsend	39W18 39W19	LTC control & SCADA completed 2018 (DG interconnection)

Table 16 – SCADA Status by Circuit

3.2.1.1.2 Feeder Level Lessons Learned/Challenges and Successes

The Company has been working to integrate SCADA in substations throughout the Massachusetts service territory. It is apparent that substations with pre-existing SCADA may need some changes to enable the functionality and capability required as part of the grid modernization projects.

3.2.1.2 OMS INTEGRATION WITH AMI

This project is software project. AMI is presently implemented across the Company's service territory. Once the integration is developed, all meters will communicate with the OMS system. Therefore, this project is not broken down on a substation or circuit basis.

3.2.2 DISTRIBUTION AUTOMATION

As described above, the Company does not have DA projects in its GMP. The Company may re-evaluate DA projects in the future and propose changes to the GMP if necessary.

3.2.3 VOLT/VAR OPTIMIZATION (VVO)

As described above, the scope of the project includes installing automated controls on all voltage and reactive power equipment on all distribution circuits. This includes controls of all capacitor banks, voltage regulators and LTCs. Voltage and Energy monitors will also be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized by a central ADMS. The communication between the ADMS and the VVO controls will be designed and installed as part of the FAN project. The design requirements of the VVO will be coordinated with the plans of the ADMS and the FAN.

3.2.3.1.1 Highlights of Feeder Level Implementation

None of the Company's feeders have VVO equipment or technology deployed yet. The following table provides a feeder by feeder view of when the voltage regulator controls, capacitor bank controls and the LTC controls will be replaced and voltage and energy monitors installed.

Substation	Circuits	Year
Townsend	15W15 15W16 15W17	2019
Lunenburg	30W30 30W31	2020
Summer St.	40W38 40W39 40W40 40W42	2021

Table 17 – VVO Schedule Through 2021

3.2.3.1.2 Feeder Level Lessons Learned/Challenges and Successes

The biggest challenge facing the Company at this point is whether to implement a VVO system using a model based or measurement based approach. This could have an impact on some of the field devices that are implemented. The Company is currently evaluating both approaches.

3.2.4 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The ADMS investment category includes two projects for the Company's GMP. The first project is an ADMS project to allow for more measurement and control of the distribution system. The Company expects the ADMS functionality to be deployed on a substation by substation and circuit by circuit basis.

The second project is to implement a DERMS system which will enable the Company to improve situational awareness and operational intelligence for this increasingly important resource. This project is not in the plan until year five of the GMP.

3.2.4.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

As described above, an ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, circuit analysis, load flow, and SCADA systems together to provide all of the information to one location. An ADMS allows its users, operators, and dispatchers a real-time view of the distribution system. In order for the ADMS to provide benefits, it must be integrated with the some of the Company's other Grid Modernization initiatives including, the Field Area Network, Substation SCADA and VVO projects.

3.2.4.1.1 Highlights of Feeder Level Implementation

The ADMS system is a software project. The Company expects that the main portion of the ADMS system will be integrated with the Company's other systems in 2020.

The functionality of the ADMS system will be implemented on a substation by substation and circuit by circuit basis. ADMS functionality will be implemented following the same priority and schedule as described above but it will be delayed by a couple of years. The Company expects the speed of deployment to accelerate as the Company gains more knowledge and experience with the ADMS.

Substation	Circuits	Year
Townsend	15W15 15W16 15W17	2021
Lunenburg	30W30 30W31	2022
Summer St.	40W38 40W39 40W40 40W42	2023

Table 18 – ADMS Schedule Through 2023

3.2.4.1.2 Feeder Level Lessons Learned/Challenges and Successes

The biggest challenge facing the Company at this point is whether to implement an ADMS system using a model based or measurement based result. This could have an impact on some of the field devices that are implemented. The Company is currently evaluating both approaches.

3.2.4.2 DER ANALYTICS AND VISUALIZATION (DERMS)

As described above, DERMS functionality will allow the Company the ability to monitor, manage and control DERs. The technology could be implemented as a module within the ADMS system or as a stand-alone system. The technology is designed to improve situational awareness and operational intelligence for this increasingly important resource. DERMS will be used by grid operators and engineers for efficient grid operations and planning.

The Company's GMP identifies DERMS to begin in year 5 of the plan. However, the Company is including DERMS functionality in its ongoing review of ADMS systems.

3.2.4.2.1 Highlights of Feeder Level Implementation

The Company has not developed a circuit by circuit plan for implementing DERMs functionality. The Company expects to develop a prioritization model to identify the circuits that will provide the most benefits from a DERMS specific standpoint.

3.2.4.2.2 Feeder Level Lessons Learned/Challenges and Successes

The DERMS project is not expected to begin within the next three years. The Company's GMP identifies DERMS to begin in year 5 of the plan.

3.2.5 COMMUNICATIONS

The Company has one project identified under the Communications investment category. The Company expects the Field Area Network project will be implemented roughly on a substation by substation and circuit by circuit basis.

3.2.5.1 FIELD AREA NETWORK

This project consists of installing a FAN including communications between collectors and endpoint devices (meters and distribution devices), and backhaul communications from collectors at each substation to the central office.

3.2.5.1.1 Highlights of Feeder Level Implementation

The Company expects that the deployment of a FAN will follow the same prioritization plan for substation and circuit deployment. However, the Company is currently in the early stages of study designed to identify the needs and requirement of the FAN and developing a specification for the network. The Company will provide more information in future annual reports.

3.2.5.1.2 Feeder Level Lessons Learned/Challenges and Successes

the Company is currently in the early stages of study designed to identify the needs and requirement of the FAN and developing a specification for the network. The Company will provide more information in future annual reports.

3.2.6 WORKFORCE MANAGEMENT

As previously described, the Workforce Management investment category includes one project for the Company's GMP. The Mobile Platform Damage Assessment project is to implement a mobility platform for storm damage assessment that can integrate damage information with the outage management system (OMS) and work order process to improve situational awareness and the speed of restoration.

3.2.6.1 MOBILE PLATFORM DAMAGE ASSESSMENT

This is a software project to implement a Mobile Platform Damage Assessment Tool to enable quicker, better-informed decisions aimed to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed, thereby allowing for a greater situational awareness. Once the project is implemented, mobile damage assessment will be available on all substations and circuits across the service territory. Therefore, this project is not broken down on a substation or circuit basis.

4 DESCRIPTION AND REPORT ON EACH INFRASTRUCTURE METRIC

As part of its decision regarding the Companies' GMPs, the Department: 1) determined that additional work was needed to develop metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the Grid Modernization objectives (Id., at 95-106.); and 2) approved the Companies' proposed statewide and company-specific infrastructure metrics. (Id., at 198-201.)

Consistent with the Department's directives, the Companies worked closely and collaboratively to develop a set of proposed performance metrics. The Companies will file a proposed set of statewide performance metrics in a separate filing. Consistent with the Department's directive, this document provides the baselines and targets for the proposed statewide performance metrics.

Also, consistent with the Department's directives, the Company has developed the following baselines for the statewide Unitil-specific infrastructure metrics. As directed by the Department, the statewide infrastructure metrics shall be reported at the substation and feeder level. For those technologies that Unitil deploys at a circuit level, it will report information on a circuit-specific basis. Similarly, for those technologies deployed at the substation level, the Company will report the information on a substation-specific basis.

The purpose of these metrics is to determine how performance can be changed because of grid modernization activities. Weather, customer behavior, economic conditions and other factors will have a significant influence on the parameters being measured under these metrics. As the Company begins to implement its GMP, the changes resulting from grid modernization may be subtle and difficult to detect. The use of baselines against which to measure ongoing performance will help develop an understanding of how Unitil's grid modernization efforts are "moving the needle" in terms of progressing towards the achievement of the Department's Grid Modernization objectives.

4.1 STATEWIDE INFRASTRUCTURE METRICS

The following statewide infrastructure metrics have been approved by the Department. In some cases, the Company is able to provide quantities for the proposed metrics. However, in some cases the information is not able to be provided without the installation of specific equipment used for measurement and verification.

4.1.1 GRID CONNECTED DISTRIBUTION GENERATION FACILITIES

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

4.1.1.1 Assumptions

The data used in these calculations consider units that have an executed Interconnection Service Agreement (“ISA”) and are in service and connected to the distribution system.

4.1.1.2 Calculation Approach

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

a. Total number by technology or fuel type – count of units by technology or fuel type
b. Nameplate capacity by technology or fuel type – sum total of nameplate capacity
c. Estimated output by technology or fuel type – sum of nameplate capacity * capacity factor * 8760 hours
d. Type of customer-owned or operated units by technology and fuel type – (i.e., count of Photo Voltaic (“PV”), wind, Combined Heat and Power (“CHP”), Fuel Cell, etc.)
e. Nameplate as a Percent of Peak Load – calculated as total nameplate capacity (MW) / peak load (MW).

4.1.1.3 Results

Over the course of 2018, the Company has interconnected 242 solar DG facilities and lost 3 gas fired DG facilities. It is estimated that the solar DG facilities have a capacity of 4,308 kW and the gas fired DG facilities had a capacity of 4,997 for a net loss of 689 kW.

Reference Attachment 1 - DG Facilities by Substation and Circuit for the detailed information with respect to DG facilities by substation and circuit. This attachment also provides a comparison to the 2017 baseline.

4.1.2 SYSTEM AUTOMATION SATURATION

This metric measures the quantity of customers served by fully automated or partially automated devices. The term s “fully automated” and “partially automated” refer to feeders for which the Company has attained optimal or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation.

4.1.2.1 Assumptions

Baseline saturation rate will be calculated based on what exists on the system as of the December 31, 2017. Ideally, over time this metric will decrease based on GMP installed devices since the metric is calculating the number of customers per device installed. As more devices are installed the metric decreases. Customers that can benefit from multiple devices will be counted as one for purposes of calculating the baseline. The installations will not be limited to the main line infrastructure and will include no-load lines and DSS lines.

4.1.2.2 Classification of Grid Modernization Devices

The following table has been provided as guidance to determine which type of equipment would be considered partially automated, fully automated or included as a sensor.

Device Type	Not Included	Partial Automation	Full Automation	Included as a Sensor
Feeder Breakers (No SCADA)		X		
Feeder Breakers (SCADA)			X	X
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)		X		
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)			X	X
Padmount Switchgear (No SCADA)		X		
Padmount Switchgear (SCADA)			X	X
Network Transformer/Protector with full SCADA			X	X
Network Transformer/Protector with monitoring, no control		X		X
Network Transformer/Protector with no SCADA		X		
Feeder Meter (e.g., ION, with comms)				X
Capacitor and Regulator with SCADA		X		X
Capacitor and Regulator no SCADA	X			
Line Sensor (with comms)				X
Fault Indicator (with comms)				X
Other Fault Indicators (no comms)	X			
Other Voltage Sensing (with comms)			X	X
Sectionalizer (no SCADA)		X		
Sectionalizer (SCADA)			X	
Customer Meter	X			
Distribution / step down Transformer	X			
Other Substation Breakers	X			
Fuse	X			

Table 19 – Classification of Grid Modernization Devices

4.1.3 Calculation Approach

As more automation is installed pursuant to Eversource's GMP, the results of this metric will be reduced.

Metric:

$$\frac{\text{Customers Served}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$$

4.1.4 Results

The system automation saturation for 2018 was calculated at 649. Reference Attachment 2 for the substation and circuit level detail.

4.1.5 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 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.

4.1.5.1 Assumptions

The base-line for this metric will be all sensors installations on distribution circuits and substations, including existing installations. The baseline will be calculated as of December 31, 2017.

4.1.5.2 Calculation Approach

The Company has established a baseline of sensors installed that exist on its distribution circuits and in substations. This infrastructure metric will then measure the percent of distribution circuits that have sensors installed.

a. Illustrative Example of quantity of sensors by device type by circuit.

Device Type	Circuit 1	Circuit 2	Circuit 3	Circuit 4
Feeder Breakers (No SCADA)				
Feeder Breakers (SCADA)				
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)				
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)				
Padmount Switchgear (No SCADA)				
Padmount Switchgear (SCADA)				
Network Transformer/Protector with full SCADA				
Network Transformer/Protector with monitoring, no control				
Network Transformer/Protector with no SCADA				
Feeder Meter (e.g., ION, with comms)				
Capacitor and Regulator with SCADA				
Capacitor and Regulator no SCADA				
Line Sensor (with comms)				
Fault Indicator (with comms)				
Other Fault Indicators (no comms)				
Other Voltage Sensing (with comms)				
Sectionalizer (no SCADA)				
Sectionalizer (SCADA)				
Customer Meter				
Distribution / step down Transformer				
Other Substation Breakers				
Fuse				

Table 20 – Illustrative Example - Quantity of sensors by device type by circuit

b. Number of circuits with installed sensors – this will be provided as a count using the information in the table above.

4.1.5.3 Results

The 2017 baseline and 2018 results for the number and percentage of circuits with installed sensors. The table below summarizes the results.

	2017 Baseline	2018 Actual
Total number of Substations/Transformers	16	16
Total number of Substations/Transformers with Sensors	13	13
% of Substation/Transformers with Sensors	81.3%	81.3%
Total number of Circuits	39	39
Total number of Circuits with Sensors	34	34
% of Substation/Transformers with Sensors	87.2%	87.2%

Table 21 – Number/Percentage of Circuits with Installed Sensors

Reference Attachment 3 for the detail behind this calculation.

4.2 COMPANY SPECIFIC INFRASTRUCTURE METRICS

The following company-specific infrastructure metrics have been approved by the Department. In some cases, the Company is able to provide baseline and target quantities for the proposed metrics. However, in some cases the baseline is not able to be provided without the installation of specific equipment used for measurement and verification.

4.2.1 NUMBER OF DEVICES OR OTHER TECHNOLOGIES DEPLOYED

This metric measures how the Company is progressing with its GMP from an equipment and/or device standpoint.

4.2.1.1 Assumptions

The number of devices for each investment be determined and/or updated from the initial GMP. The number of devices installed will be compared to the total number of devices planned by circuit for each investment.

The Company notes that its GMP did not include a significant amount of detail and the Company is in the process of developing detailed designs and detailed plans for each investment area. The Company will continue to update this as more detailed designs are completed.

4.2.1.2 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or other technologies deployed
b. Total number of devices planned
c. Percent – Number of devices installed / total number of devices planned

4.2.1.3 Results

Some of the investments identified are software projects, which are listed as a single technology to deploy. OMS Integration with AMI and Mobile Platform Damage Assessment will be implemented across the service territory at the same time.

The SCADA investments identified in the table were all implemented prior to the Department's Grid Mod order.

The Company's GMP did not include ADMS or DERMS investments in the first three years of the plan. The Company is currently evaluating these investments and will develop a plan for their implementation. The Company has included these investments in this table and will update this metric in the next annual filing once it has more information on how these investments will be implemented.

The Company has hired a consultant and is currently under active review of the AN The Company will update this metric in the next annual filing.

The table below is used to summarize the results of this metric.

Grid Modernization Investments	Number of devices or other technologies deployed	Total number of devices planned	Percent – Number of devices installed / total number of devices planned
Monitoring and Control			
SCADA[3]	18	39	46%
OMS Integration with AMI[4]	0	1	0%
Volt/VAr Optimization			
VVO Capacitor Banks	0	41	0%
VVO Automated Voltage Regulators	0	41	0%
VVO Automated LTC	0	16	0%
Monitoring[5]			
3 Phase	0	32	0%
1 Phase	0	41	0%
Advanced Distribution Management System			
ADMS	Under Review	Under Review	Under Review
DERMS	Under Review	Under Review	Under Review
Communications			
Field Area Network	Under Review	Under Review	Under Review
Workforce Management			
Mobile Platform Damage Assessment[6]	0	1	0%

Table 22 – Quantity of Devices by Investment

4.2.2 ASSOCIATED COST FOR DEVELOPMENT

This metric measures the associated costs for the number of devices or technologies installed and is designed to measure how the Company is progressing.

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[3] SCADA functionality identified as number of circuits with SCADA technology deployed

[4] OMS Integration with AMI is a software project.

[5] Monitoring not included as a specific project but required for VVO to effectively operate

[6] Mobile Platform Damage Assessment is a software project.

4.2.2.1 Assumptions

The cost of devices or technologies for each investment will need to be determined and/or updated from the initial GMP. The cost of devices installed will be compared to the total cost of devices planned by circuit for each investment.

Eversource notes that its GMP did not include a significant amount of detail and may need to be supplemented with detailed design and planning analysis to clarify the year-by-year construction plans.

4.2.2.2 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Cost of devices or other technologies deployed
b. Total cost of devices planned
c. Percent – Cost of devices installed / total cost of devices planned

4.2.2.3 Results

The Company did not implement any investments in 2018 that were subject to cost recovery. As such, the table below identifies no spending for Grid Modernization investments. All investments made in technology or devices were made either prior to the Department's Order or the project has not been completed and closed to plant.

The Total Cost of Devices Planned is the most up to date estimate of the project for the ten year timeframe. Where an updated estimate is not available, the amount in the GMP has been used.

Grid Modernization Investments	Cost of devices or other technologies deployed	Total cost of devices planned	Percent – Cost of devices installed / total cost of devices planned
Monitoring and Control			
SCADA[7]	0	$1,470,000	0%
OMS Integration with AMI	0	$105,000	0%
Volt/VAr Optimization			
VVO Capacitor Banks	0	$1,690,000	0%
VVO Automated Voltage Regulators	0	$520,000	0%
VVO Automated LTC	0	$940,000	0%
Monitoring 3 Phase 1 Phase	 0 0	 Under Review Under Review	 0% 0%
Advanced Distribution Management System			
ADMS	0	$2,100,000	0%
DERMS	0	$650,000	0%
Communications			
Field Area Network	0	$2,800,000	0%
Workforce Management			
Mobile Platform Damage Assessment	0	$400,000	0%

Table 23 – Total Costs of Devices Planned

4.2.3 REASONS FOR DEVIATION BETWEEN ACTUAL AND PLANNED DEPLOYMENT FOR THE PLAN YEAR

This metric is designed to measure how the Company is progressing under its GMO on a year-by-year basis.

[7] SCADA functionality identified as number of circuits with SCADA technology deployed

4.2.3.1 Assumptions

The quantity and cost of devices or technology for each investment will need to be determined and/or updated from the initial GMP on a year-by-year basis. The quantity and cost of devices or technology installed in a given GMP investment year will be compared on a year-by-year basis and any variations will be quantified and addressed.

The Company notes that its GMP did not include a significant amount of detail and may need to be supplemented with detailed design and planning analysis to clarify the year-by-year construction plans.

4.2.3.2 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or technology installed versus plan for a given year
b. Cost of devices or technologies installed versus plan for a given year
c. Reason for discrepancies

4.2.3.3 Results

As described above, the Company did not implement any of the grid modernization investments in 2018. When the Company initially filed its GMP, there was no guidance from the Department as to how long the review of the GMPs would take. The Company made the decision to not continue with the review, modification and implementation of the GMP. The Company did not want to move forward and implement a project without formal guidance and approval from the Department.

The Department's Order identified which investments were supported and preapproved and which projects required more research and investigation. The Company appreciates this direction from the Department. The Company's decision to not move forward with GMP investments prior to receipt of the Order was prudent since not all of its proposed investments were approved by the Department.

4.2.4 PROJECTED DEPLOYMENT FOR THE REMAINDER OF THE THREE YEAR TERM

This metric is designed to measure how the Company is progressing under its GMP on a year-by-year basis. This will be used for the following year comparison of the plan versus the actual implementation completed in the following year.

4.2.4.1 Assumptions

The year-by-year investment plan is subject to change based upon the quantity of work completed, the availability of the technology, material lead times, contractor availability, etc. The revised investment plan each year will be used as the basis of comparison for the following year's GMP work.

4.2.4.2 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or technology to be installed the following year
b. Cost of devices or technologies installed the following year

4.2.4.3 Results

The table below identifies the expected spending for 2019. In some cases, the Company is still designing the investment projects and does not have an accurate estimate of the investment yet.

Grid Modernization Investments	Number of devices or technology to be installed the following year	Cost of devices or technologies installed the following year
Monitoring and Control		
SCADA[8]	4	$720,000
OMS Integration with AMI	1	$105,000
Volt/VAr Optimization		
VVO Capacitor Banks	5	$206,000
VVO Automated Voltage Regulators	1	$52,000
VVO Automated LTC	1	Included Above[9]
Monitoring 3 Phase 1 Phase	 Under Review Under Review	 Under Review Under Review
Advanced Distribution Management System		
ADMS	Under Review	Under Review
DERMS	Under Review	Under Review
Communications		
Field Area Network	Under Review	Under Review
Workforce Management		
Mobile Platform Damage Assessment	0[10]	$70,000

Table 24 – Projected Deployment Through 2020

[8] SCADA functionality identified as number of circuits with SCADA technology deployed

[9] Included in SCADA estimate.

[10] It is expected that this investment will be completed in 2020 at an estimated total cost of $105,000.

5 DISTRIBUTED ENERGY RESOURCES (DERS)

DER interconnections have been a focus of the Company. That is the primary reason the Company proposed the installation of 3V0 protection schemes that enable an increased quantity and capacity of DERs to interconnect. Unfortunately, the Company's approved grid modernization investments approved by the Department do not include 3V0 investments. The Company now faces the challenge of individual residential DER interconnections causing backflow through the substation, resulting in the need for costly system improvements. Individual residential DER interconnections are generally not capable of economically supporting system investments such as 3V0. This section of the report describes the status of DERs interconnected to the distribution system.

5.1 OVERVIEW OF DERS ON DISTRIBUTION SYSTEM

As of year-end 2018, Unitil has 1,654 customer owned DER facilities and 1 utility owned solar facility. Of the customer facilities, 1651 (99.8%) are solar. The remaining consists of 4 gas turbines and 1 wood fired turbine. The total capacity of the solar units is 25,567 kVA; approximately 27% of the 2018 system peak load of 93,323 kVA.

In addition to the facilities on-line, there were 59 facilities that were approved for installation totaling an additional 22,860 kVA. The measured net minimum day-time system load at the system supply bus in 2018 was 17,035 kVA.

20% of the substation transformers are expected to experience reverse power flow at light load times.

5.2 LESSONS LEARNED INTEGRATING DERS

The required system modifications, due to the integration of the large amount of DER, are becoming larger in scope and more costly than in years prior. It is now common for substation modifications to be necessary to install a large DER facility. The aggregate amount of small DERs is also requiring an increased amount of system modifications.

The aggregate amount of small and residential DER facilities installed, in addition to the large DER facilities, are creating backflow through the substation transformers. This requires special protection schemes to be installed at the substation level. A number of times, this backflow triggers from the large amount of residential DER installed after a large DER has already interconnected. In studying the large DER facilities, the amount of generation at the time may not have triggered the need for specials system modifications at the substation. However, the large number of small DERs installed after a larger interconnection creates a need for costly system modification.

The analysis screens of the MA DG Interconnection standards did not anticipate the amount of small and residential DER facilities affecting substation flow. The Company has expanded the analysis screens for the small DER applications in an attempt to capture this impact. However, the cost of the system modifications cannot be borne by a single small DER which happens to be the one interconnection to cause the backflow condition.

The number of substations that are experiencing reverse power flow is increasing, and the effect of the DER on the distribution system may now be affecting the transmission system. The scope of studies required will need to increase to include analysis on the transmission system.

6 PERFORMANCE METRICS

At this time, the statewide performance metrics and the spreadsheet template have not been approved by the Department. Therefore, the Company is not including any of the information on the statewide performance metrics. The Company has provided some background on the development of the statewide performance metrics.

In D.P.U. 12-76-B, the Department of Public Utilities (the "Department") directed the Companies to include in their GMPs metrics that track the implementation of grid modernization technologies and systems.

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

In approving the metrics, the Department found that the purpose of the metrics will be to record and report information: the metrics will not, at present, be tied to incentives or penalties. Id., at 197. The Department ordered the Companies to establish baselines by which the grid-facing performance metrics will be measured against and to file them within 90 days of the Order. Id., at 203. To assist in the development of these baselines, the Department directed each of the Companies to develop and maintain information on its system design, operational characteristics (e.g., voltage, loading, line losses), and ratings prior to any deployment of preauthorized grid-facing technologies. Id. Additionally, the Department directed the Companies, when developing the proposed baselines to use, to the extent possible, information reported in the annual service quality filings, as well as other publicly available information. Id.

As part of its decision regarding the Companies' GMPs, the Department determined that additional work was needed to develop metrics that appropriately track the quantitative benefits associated with pre-authorized grid-facing investments, and progress toward the Grid Modernization objectives. Id., at 95-106.

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

Additionally, the Department's Memorandum scheduled a technical session on the Companies' August 15, 2018 performance metrics filing. The Companies participated in the technical session, including presenting on the proposed performance metrics. Following the technical session, the Department issued a Memorandum that set out required revisions to the August 15, 2018 performance metrics, as well as directed the Companies to develop additional performance metrics ("Metrics Revision Memorandum"). The Metrics Revision Memorandum set April 2, 2019, as the deadline for the Companies to file the revised and new performance metrics, with initial comments on the Companies' filing due on April 16, 2019, and reply comments due on April 23, 2019. Consistent with the directives contained in the Metrics Revision Memorandum, the Companies provided the required revisions to the initial set of performance metrics, as well as the new metrics required by the Department.

7 RESEARCH, DESIGN AND DEVELOPMENT

At the present time, the Company does not have any specific RD&D investments to propose to the Department. However, the Company is currently researching and developing a utility scale battery storage project as a means to defer substation investment. The Company is currently evaluating the costs and potential revenues associated with the ISO-NE markets a unit like this can participate in.

8 CONCLUSION

Implementation of the Company's GMP has begun with a detailed review of the projects originally submitted in 2015. This review is necessary due to the level of detail of the design and cost estimates provided in its GMP as well as the changes in technology and costs over the past 4 years.

The Company plans to take a measured approach to implementation, working to control costs whenever possible and use internal resources as much as possible. The Company has developed a project management structure that will ensure grid modernization is implemented in an efficient manner.

The Company presents this report as an update of progress made since the Order in May 2018 through the end of 2018. The Company would request that the Companies and the Department work together to refine the requirements of this annual report to make certain the information provided here is responsive to the Department's goal of being able to measure progress towards grid modernization.

Attachment 1

DG Facilities by Substation and Circuit

		Total Number of DG Facility By Type				Total Nominal Capacity of DG Facility by Type				Estimated Annual Output (kWh) by Type				Type of customer-owned or operated units by type				Circuit or Transformer Peak Load (kVA)	Nameplate as % of Peak Load
Substation/Transformer	Circuit Number	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total		
Beech St.#1 Xfmr		**101**	**1**	**-**	**102**	**1,599**	**1**	**-**	**1,600**	**2,605,176**	**10,512**	**-**	**2,615,688**	**101**	**1**	**-**	**102**	**11,000**	**14.55%**
	01W01	2	-	-	2	423		-	423	689,871	-	-	689,871	2	-	-	2	4,000	10.59%
	01W02	56	1	-	57	499	1	-	500	813,140	10,512	-	823,652	56	1	-	57	3,000	16.68%
	01W04	43	-	-	43	676	-	-	676	1,102,164	-	-	1,102,164	43	-	-	43	2,350	28.78%
	01W06																	4,000	
Canton St. 13.8 kV #1 Xfmr		**91**	**-**	**-**	**91**	**713**	**-**	**-**	**713**	**1,161,815**	**-**	**-**	**1,161,815**	**91**	**-**	**-**	**91**	**4,063**	**17.55%**
	11W11	91	-	-	91	713	-	-	713	1,161,815	-	-	1,161,815	91	-	-	91	3,952	18.04%
Canton St. 4.16 kV #2 Xfmr		**32**	**-**	**-**	**32**	**215**	**-**	**-**	**215**	**349,571**	**-**	**-**	**349,571**	**32**	**-**	**-**	**32**	**1,919**	**11.18%**
	11H10	27	-	-	27	180	-	-	180	293,391	-	-	293,391	27	-	-	27	1,042	17.27%
	11H11	5	-	-	5	34	-	-	34	56,180	-	-	56,180	5	-	-	5	1,004	3.43%
Lunenburg 13.8 kV Xfmr		**231**	**-**	**-**	**231**	**4,928**	**-**	**-**	**4,928**	**8,030,236**	**-**	**-**	**8,030,236**	**231**	**-**	**-**	**231**	**8,469**	**58.19%**
	30W30	133	-	-	133	1,295	-	-	1,295	2,109,272	-	-	2,109,272	133	-	-	133	4,685	27.63%
	30W31	98	-	-	98	3,634	-	-	3,634	5,920,964	-	-	5,920,964	98	-	-	98	3,984	91.22%
Nockege 4.16 kV Xfmr		**71**	**-**	**-**	**71**	**468**	**-**	**-**	**468**	**763,241**	**-**	**-**	**763,241**	**71**	**-**	**-**	**71**	**1,944**	**24.10%**
	20H22	69	-	-	69	456	-	-	456	742,874	-	-	742,874	69	-	-	69	1,640	27.79%
	20H24	2	-	-	2	13	-	-	13	20,367	-	-	20,367	2	-	-	2	365	3.42%
Pleasant St. 13.8 kV Xfmr		**226**	**-**	**-**	**226**	**3,051**	**-**	**-**	**3,051**	**4,971,397**	**-**	**-**	**4,971,397**	**226**	**-**	**-**	**226**	**7,951**	**38.37%**
	31W34	31	-	-	31	155	-	-	155	252,306	-	-	252,306	31	-	-	31	2,143	7.23%
	31W37	117	-	-	117	1,313	-	-	1,313	2,140,001	-	-	2,140,001	117	-	-	117	3,872	33.92%
	31W38	78	-	-	78	1,583	-	-	1,583	2,579,090	-	-	2,579,090	78	-	-	78	2,940	53.84%
Princeton Rd #2 Xfmr		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,625**	**0.00%**
	50W53		-		-		-	-	-	-	-	-	-	-	-	-	-	7,465	0.00%
Princeton Rd #3 Xfmr		**96**	**-**	**-**	**96**	**1,374**	**-**	**-**	**1,374**	**2,237,959**	**-**	**-**	**2,237,959**	**96**	**-**	**-**	**96**	**10,000**	**13.74%**
	50W51	74	-	-	74	455	-	-	455	742,027	-	-	742,027	74	-	-	74	1,500	30.36%
	50W55	8	-	-	8	60	-	-	60	97,208	-	-	97,208	8	-	-	8	4,900	1.22%
	50W56	14	-	-	14	858	-	-	858	1,398,724	-	-	1,398,724	14	-	-	14	4,533	18.94%

		Total Number of DG Facility By Type				Total Nominal Capacity of DG Facility by Type				Estimated Annual Output (kWh) by Type				Type of customer-owned or operated units by type				Circuit or Transformer Peak Load (kVA)
Substation/Transformer	Circuit Number	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	
River St. 13.8 kV Xfmr		**111**	**-**	**-**	**111**	**931**	**9**	**-**	**940**	**1,516,592**	**81,293**	**-**	**1,597,885**	**111**	**-**	**-**	**111**	**7,100**
	25W29								-									4,000
	25W27	87	-	-	87	774	9	-	783	1,260,782	81,293	-	1,342,075	87	-	-	87	2,494
	25W28	24	-	-	24	157	-	-	157	255,810	-	-	255,810	24	-	-	24	1,400
Sawyer Passway 13.8 kV Xfmr T1		**27**	**2**	**-**	**29**	**331**	**73**	**-**	**404**	**539,514**	**635,976**	**-**	**1,175,490**	**27**	**2**	**-**	**29**	**4,600**
	22W17		-	-	-		-	-	-	-	-	-	-	-	-	-	-	1,100
	22W2		-		-		-	-	-	-	-	-	-	-	-	-	-	769
	22W1	27	2		29	331	73	-	404	539,514	635,976	-	1,175,490	27	2	-	29	4,600
	22W3		-		-		-	-	-	-	-	-	-	-	-	-	-	829
Sawyer Passway 13.8 kV Xfmr T2		**1**	**-**	**-**	**1**	**1,000**	**-**	**-**	**1,000**	**1,629,360**	**-**	**-**	**1,629,360**	**1**	**-**	**-**	**1**	**4,600**
	22W8		-		-		-	-	-	-	-	-	-	-	-	-	-	737
	22W10		-		-		-	-	-	-	-	-	-	-	-	-	-	1,944
	22W11		-		-		-	-	-	-	-	-	-	-	-	-	-	1,200
	22W12	1	-		1	1,000	-	-	1,000	1,629,360	-	-	1,629,360	1	-	-	1	1,000
Summer St. 13.8 kV B123 Xfmr		**110**	**1**	**-**	**111**	**2,772**	**1,800**	**-**	**4,572**	**4,515,796**	**15,768,000**	**-**	**20,283,796**	**110**	**1**	**-**	**111**	**9,856**
	40W38		1		1		1,800	-	1,800	-	15,768,000	-	15,768,000	-	1	-	1	2,200
	40W39	4	-		4	1,024	-	-	1,024	1,667,813	-	-	1,667,813	4	-	-	4	4,000
	40W40	74	-		74	1,413	-	-	1,413	2,301,854	-	-	2,301,854	74	-	-	74	7,600
	40W42	32	-		32	335	-	-	335	546,129	-	-	546,129	32	-	-	32	3,500
Townsend 13.8 kV Xfmr		**189**	**-**	**-**	**189**	**1,727**	**-**	**-**	**1,727**	**2,813,962**	**-**	**-**	**2,813,962**	**189**	**-**	**-**	**189**	**10,270**
	15W15		-		-		-	-	-	-	-	-	-	-	-	-	-	3,673
	15W16	139	-		139	1,383	-	-	1,383	2,253,829	-	-	2,253,829	139	-	-	139	5,450
	15W17	50	-		50	344	-	-	344	560,133	-	-	560,133	50	-	-	50	1,442
Rindge Road Tap	35W36	**89**	**-**	**-**	**89**	**2,428**	**-**	**-**	2,428	**3,955,524**	**-**	**-**	**3,955,524**	**89**	**-**	**-**	**89**	**2,935**
W. Townsend 13.8 kV Xfmr		**276**	**-**	**-**	**276**	**4,031**	**-**	**-**	4,031	**6,568,105**	**-**	**-**	**6,568,105**	**276**	**-**	**-**	**276**	**7,728**
	39W18	118	-		118	861	-	-	861	1,402,749	-	-	1,402,749	118	-	-	118	5,051
	39W19	158	-		158	3,170	-	-	3,170	5,165,356	-	-	5,165,356	158	-	-	158	2,868
Flagg Pond 69kV		**-**	**-**	**1**	**1**	**-**	**-**	**16,000**	**16,000**	**-**	**-**	**140,160,000**	**140,160,000**	**-**	**-**	**1**	**1**	**93,300**

		Total Number of DG Facility By Type				Total Nominal Capacity of DG Facility				Estimated Annual Output (kWh) by Type				Type of customer-owned or				Type of utility-owned or operated units by type			
Substation/Transformer		Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total	Solar	Gas	Wood	Total
2018 Total		**1,651**	**4**	**1**	**1,656**	**25,567**	**1,883**	**16,000**	**43,450**	**41,658,246**	**16,495,781**	**140,160,000**	**198,314,027**	**1,650**	**4**	**1**	**1,655**	**1**	**-**	**-**	**1**
2017 Baseline		**1,409**	**7**	**1**	**1,417**	**21,259**	**6,880**	**16,000**	**44,139**	**34,638,727**	**60,268,099**	**140,160,000**	**235,066,826**	**1,408**	**7**	**1**	**1,416**	**1**	**-**	**-**	**1**
Difference		**242**	**(3)**	**-**	**239**	**4,308**	**(4,997)**	**-**	**(689)**	**7,019,519**	**(43,772,318)**	**-**	**(36,752,799)**	**242**	**(3)**	**-**	**239**	**-**	**-**	**-**	**-**

Attachment 2

System Automation Saturation

			Partially Automated								Fully Automated Devices						
Substation/Transformer	Circuit	Average Number of Customers Served 2018	Feeder Breakers (No SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)	Padmount Switchgear (No SCADA)	Network Transformer /Protector with monitoring, no control	Network Transformer /Protector with no SCADA	Capacitor and Regulator with SCADA	Sectionalizer (no SCADA)	Count of Partially Automated Devices	Feeder Breakers (SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)	Padmount Switchgear (SCADA)	Network Transformer /Protector with full SCADA	Sectionalizer (SCADA)	Count of Fully Automated Devices	System Automation Saturation
Beech St.#1 Xfmr		**3971**	**0**	**2**	**0**	**0**	**0**	**1**	**0**	**3**	**2**	**0**	**0**	**0**	**0**	**2**	**1135**
	1W1	391	0	0	0	0	0	0	0	0	1	0	0	0	0	1	391
	1W2	1940	0	1	0	0	0	0	0	1	0	0	0	0	0	0	3880
	1W4	1639	0	1	0	0	0	0	0	1	0	0	0	0	0	0	3278
	1W6	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
Canton St. 13.8 kV #1 Xfmr		**1718**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**#DIV/0!**
	11W11	1718	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
Canton St. 4.16 kV #2 Xfmr		**1108**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**#DIV/0!**
	11H10	736	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
	11H11	372	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
Lunenburg 13.8 kV Xfmr		**2965**	**1**	**2**	**0**	**0**	**0**	**0**	**0**	**3**	**1**	**2.5**	**0**	**0**	**0**	**3.5**	**593**
	30W30	1328	1	0	0	0	0	0	0	1	0	0	0	0	0	0	2656
	30W31	1637	0	2	0	0	0	0	0	2	1	2.5	0	0	0	3.5	364
Nockege 4.16 kV Xfmr		**1125**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**#DIV/0!**
	20H22	898	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
	20H24	227	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
Pleasant St. 13.8 kV Xfmr		**3740**	**0**	**0.5**	**0**	**0**	**0**	**0**	**0**	**0.5**	**3**	**2.5**	**0**	**0**	**0**	**5.5**	**650**
	31W34	1240	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1240
	31W37	1221	0	0.5	0	0	0	0	0	0.5	1	1.5	0	0	0	2.5	444
	31W38	1279	0	0	0	0	0	0	0	0	1	1	0	0	0	2	640
Princeton Rd #2 Xfmr		**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**1**	**1**
	50W53	1	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1
Princeton Rd #3 Xfmr		**996**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**2**	**4**	**0**	**0**	**0**	**0**	**4**	**199**
	50W51	656	0	0	0	0	0	0	0	0	1	0	0	0	0	1	656
	50W55	191	0	0	0	0	0	0	0	0	1	0	0	0	0	1	191
	50W56	149	0	0	0	0	0	0	0	0	1	0	0	0	0	1	149
Rindge Road		**762**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**1524**
	35W36	762	1	0	0	0	0	0	0	1	0	0	0	0	0	0	1524
River St. 13.8 kV Xfmr		**1895**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**1895**
	25W27	1213	1	0	0	0	0	0	0	1	0	0	0	0	0	0	2426
	25W28	682	1	0	0	0	0	0	0	1	0	0	0	0	0	0	1364

Substation/Transformer	Circuit	Average Number of Customers Served 2018	Feeder Breakers (No SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)	Padmount Switchgear (No SCADA)	Network Transformer /Protector with monitoring, no control	Network Transformer /Protector with no SCADA	Capacitor and Regulator with SCADA	Sectionalizer (no SCADA)	Count of Partially Automated Devices	Feeder Breakers (SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)	Padmount Switchgear (SCADA)	Network Transformer /Protector with full SCADA	Sectionalizer (SCADA)	Count of Fully Automated Devices	System Automation Saturation
Sawyer Passway 13.8 kV Xfmr T1		**2242**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**1**	**6.5**	**0**	**0**	**0**	**0**	**6.5**	**320**
	22W17	1	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1
	22W2	162	0	0	0	0	0	0	0	0	1	0	0	0	0	1	162
	22W1	2060	0	0	0	0	0	0	0	0	1	0	0	0	0	1	2060
	22W3	19	0	0	0	0	0	0	0	0	1	0	0	0	0	1	19
Sawyer Passway 13.8 kV Xfmr T2		**325**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**1**	**6.5**	**0**	**0**	**0**	**0**	**6.5**	**46**
	22W8	163	0	0	0	0	0	0	0	0	1	0	0	0	0	1	163
	22W10	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0
	22W11	162	0	0	0	0	0	0	0	0	1	0	0	0	0	1	162
	22W12	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0
Summer St. 13.8 kV B123 Xfmr		**3699**	**2**	**1.5**	**0**	**0**	**0**	**0**	**0**	**3.5**	**3**	**1**	**0**	**0**	**0**	**4**	**643**
	40W38	4	0	0	0	0	0	0	0	0	1	0	0	0	0	1	4
	40W39	420	0	0	0	0	0	0	0	0	1	1	0	0	0	2	210
	40W40	1571	1	1.5	0	0	0	0	0	2.5	0	0	0	0	0	0	1257
	40W42	1704	1	0	0	0	0	0	0	1	0	0	0	0	0	0	3408
Townsend 13.8 kV Xfmr		**2058**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**4116**
	15W15	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
	15W16	1500	1	0	0	0	0	0	0	1	0	0	0	0	0	0	3000
	15W17	557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	#DIV/0!
Wallace Rd		**1**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**1**
	1341	1	2	0	0	0	0	0	0	2	0	0	0	0	0	0	1
W. Townsend 13.8 kV Xfmr		**3264**	**0**	**2**	**0**	**0**	**0**	**1**	**0**	**3**	**2**	**1**	**0**	**0**	**0**	**3**	**725**
	39W18	1965	0	1	0	0	0	0	0	1	1	0	0	0	0	1	1310
	39W19	1299	0	1	0	0	0	0	0	1	1	1	0	0	0	2	520
		29870								20						36	649

Attachment 3

Number/Percentage of Circuits with Installed Sensors

Substation/Transformer	Circuit	Feeder Breakers (SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)	Padmount Switchgear (SCADA)	Network Transformer/ Protector with full SCADA	Network Transformer /Protector with monitoring, no control	Feeder Meter (e.g., ION, with comms)	Capacitor and Regulator with SCADA	Line Sensor (with comms)	Fault Indicator (with comms)	Other Voltage Sensing (with comms)	Total Number of Sensors by Circuit/Substation
Beech St.#1 Xfmr		**5**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**1**	**7**
	1W1	1	0	0	0	0	0	0	0	0	1	2
	1W2	1	0	0	0	0	0	0	0	0	0	1
	1W4	1	0	0	0	0	0	0	0	0	0	1
	1W6	1	0	0	0	0	0	0	0	0	0	1
Canton St. 13.8 kV #1 Xfmr		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	11W11	0	0	0	0	0	0	0	0	0	0	0
Canton St. 4.16 kV #2 Xfmr		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**2**
	11H10	0	0	0	0	0	0	0	0	0	1	1
	11H11	0	0	0	0	0	0	0	0	0	1	1
Lunenburg 13.8 kV Xfmr		**1**	**2.5**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**4**	**9.5**
	30W30	0	0	0	0	0	0	0	0	0	3	3
	30W31	1	2.5	0	0	0	0	0	0	0	1	4.5
Nockege 4.16 kV Xfmr		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**5**
	20H22	0	0	0	0	0	0	0	0	0	5	5
	20H24	0	0	0	0	0	0	0	0	0	0	0
Pleasant St. 13.8 kV Xfmr		**3**	**3.5**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**4**	**12.5**
	31W34	1	0	0	0	0	0	0	0	0	3	4
	31W37	1	2.5	0	0	0	0	0	0	0	0	3.5
	31W38	1	1	0	0	0	0	0	0	0	0	2
Princeton Rd #2 Xfmr		**1**	**0**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**0**	**3**
	50W53	1	0	0	0	0	0	0	0	0	0	1
Princeton Rd #3 Xfmr		**4**	**0**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**1**	**7**
	50W51	1	0	0	0	0	0	0	0	0	0	1
	50W55	1	0	0	0	0	0	0	0	0	1	2
	50W56	1	0	0	0	0	0	0	0	0	0	1
Rindge Road		**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**
	35W36	0	2	0	0	0	0	0	0	0	1	3
River St. 13.8 kV Xfmr		**2**	**0**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**5**	**9**
	25W27	1	0	0	0	0	0	0	0	0	4	5
	25W28	1	0	0	0	0	0	0	0	0	1	2

Substation/Transformer	Circuit	Feeder Breakers (SCADA)	Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)	Padmount Switchgear (SCADA)	Network Transformer/ Protector with full SCADA	Network Transformer /Protector with monitoring, no control	Feeder Meter (e.g., ION, with comms)	Capacitor and Regulator with SCADA	Line Sensor (with comms)	Fault Indicator (with comms)	Other Voltage Sensing (with comms)	Total Number of Sensors by Circuit/Substation
Sawyer Passway 13.8 kV Xfmr T1		**5.5**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**4**	**11.5**
	22W17	1	0	0	0	0	0	0	0	0	0	1
	22W2	1	0	0	0	0	0	0	0	0	0	1
	22W1	1	0	0	0	0	0	0	0	0	4	5
	22W3	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway 13.8 kV Xfmr T2		**5.5**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**7.5**
	22W8	1	0	0	0	0	0	0	0	0	0	1
	22W10	1	0	0	0	0	0	0	0	0	0	1
	22W11	1	0	0	0	0	0	0	0	0	0	1
	22W12	1	0	0	0	0	0	0	0	0	0	1
Summer St. 13.8 kV B123 Xfmr		**2**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**11**
	40W38	1	0	0	0	0	0	0	0	0	0	1
	40W39	1	1	0	0	0	0	0	0	0	3	5
	40W40	0	0	0	0	0	0	0	0	0	5	5
	40W42	0	0	0	0	0	0	0	0	0	0	0
Townsend 13.8 kV Xfmr		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**6**	**6**
	15W15	0	0	0	0	0	0	0	0	0	0	0
	15W16	0	0	0	0	0	0	0	0	0	4	4
	15W17	0	0	0	0	0	0	0	0	0	2	2
Wallace Road		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	1341	0	0	0	0	0	0	0	0	0	0	0
W. Townsend 13.8 kV Xfmr		**2**	**1**	**0**	**0**	**0**	**1**	**2**	**0**	**0**	**4**	**10**
	39W18	1	0	0	0	0	0	0	0	0	2	3
	39W19	1	1	0	0	0	0	0	0	0	2	4

Total number of Substations/Transformers	**16**
Total number of Substations/Transformers with Sensors	**13**
% of Substation/Transformers with Sensors	**81.3%**
Total number of Circuits	**39**
Total number of Circuits with Sensors	**34**
% of Substation/Transformers with Sensors	**87.2%**