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

2020
Grid Modernization Plan
Annual Report

Massachusetts Department of Public Utilities
D.P.U. 21-30

Dated: 4-1-2021

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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

UES – Unitil Energy Systems, Inc. (Unitil's affiliate distribution company in NH)

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") each submitted a comprehensive GMP that described a scope and schedule for Grid Modernization investments.

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, it believes, prudent, since not all of the proposed investments were approved by the Department.

On January 10, 2019, the Department requested comments on the appropriate form and content of the annual report to be submitted by the Companies. Additionally, the Department requested comments on the reporting template. The Companies and other interested stakeholders filed comments on February 6, 2019. On March 13, 2019 the Department held a technical conference regarding the Grid Modernization Annual Reports. Additionally, the Companies responded to DOER's February 20, 2019 reply comments.

On March 29, 2019, the Department issued an order approving the Grid Modernization Annual Report Outline/Table of Contents and extended the deadline for submission of Grid Modernization Annual Reports for plan year 2018 until May 1, 2019. On May 1, 2019, the Company filed its 2018 Annual Grid Modernization Report.

On December 6, 2019, the Department issued an Order adopting the Grid Modernization Annual Report templates and required the Companies to file subsequent Annual Reports with (1) functional versions of the approved templates and (2) the outline for the narrative sections approved on May 29, 2019. The Department also required the Companies to file a supplemental 2018 Grid Modernization Annual Report to address the changes in the approved templates. On January 31, 2020, the Company filed a supplemental 2018 Grid Modernization Annual Report template. On April 1, 2020, the Company filed its Grid Modernization Plan Annual Report for Calendar Year 2019.

On April 14, 2020, a hearing officer memorandum was issued in dockets 15-120, 15-121 and 15-122. In this memorandum, the Department docketed the 2018 Grid Modernization Annual reports as D.P.U. 20-45 and the 2019 Grid Modernization Annual Reports as D.P.U. 20-46. The memo further described the Department's assignment of docket numbers was not intended as the initiation of a formal investigation into the 2018 and 2019 Grid Modernization Annual Reports. The Department issued and the Company responded to five sets of information requests concerning the 2019 Grid Modernization Annual Reports in D.P.U. 20-46.

On May 12, 2020, the Department issued Order 15-120-D, 15-121-D and 15-122-D which extended the current three-year grid modernization plan investment term and established revised filing date for subsequent grid modernization plans. In this order, the Department extended the grid modernization plan investment term and allowed the Companies to implement their approved grid modernization plans, subject to the company-specific budget cap, for an additional year through calendar year 2021. The order also directed the next grid modernization plan filing for calendar years 2022 to 2024 to be due by July 1, 2021.

On March 4, 2021 the Department assigned the docket number D.P.U. 21-30 to the 2020 Grid Modernization Annual Reports due to be filed by April 1, 2021. On March 11, 2021, the Department issued a hearing officer memorandum to implement modifications to the reporting templates, for use in future Grid Modernization Annual Reports. The Department directed the distribution companies to coordinate to ensure formatting consistency with respect to the modifications to the reporting templates. The modifications will give the Department and stakeholders the ability to more easily cross reference and compare each company's progress in implementing its Grid Modernization Plan.

This 2020 Grid Modernization Annual Report and associated templates are filed pursuant to the Department's Order in DPU 15-121-C. The report is designed to demonstrate that the Company is making measurable progress towards implementing the preauthorized investments as identified in its Grid Modernization filing and as modified in the 2018 and 2019 Grid Modernization Annual Reports.

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, evaluating proposals, developing more accurate project estimates and project implementation.

This Annual Grid Modernization Report covers activities in 2020 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.

Overall, the Company is making significant progress towards the design and implementation of its Grid Modernization plan. The templates developed as a means to measure progress associated with the plan focus primarily on number of units installed and the amount of money spent on the implementation. The Company's efforts in 2018, 2019 and part of 2020 have included the following foundational steps: analysis, evaluation, specification, RFP, evaluation, initial purchase, and scope of work development. The Company's analysis and design work has identified efficiencies such as combining VVO functionality with the ADMS and adjusting the schedule to align the FAN, VVO, ADMS and SCADA projects. A considerable amount of effort has been expended, even though these efforts are not easily quantified with number of units installed or amount of money spent.

In 2020, the Company was successful in beginning the implementation of its ADMS system (ahead of schedule), VVO deployment for Townsend substation and associated circuits, further expansion of SCADA, and progress towards an enhanced integration of AMI and OMS. This approach has already proven beneficial to our grid modernization efforts.

The Company also experienced some challenges associated with the COVID -19 pandemic. The COVID-19 pandemic had a quick and dramatic impact on the Company, our workforce and customers. Safe and reliable service continues to be the top priority of the Company. The pandemic had a negative impact on the implementation of our GMP from a scheduling and material delivery standpoint. It is difficult to quantify the total effect the pandemic will have to the GMP implementation schedule as the Company continues to experience long lead times for certain equipment but continues to make progress towards implementing our GMP.

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

Since the Order was issued, the Company has been working on the more detailed design and analysis required to implement the investments identified in its GMP. In 2019, after detailed discussion with the project teams and vendors, the Company decided to modify the plan schedule to coordinate the design and installation of SCADA, ADMS, VVO and FAN projects. In 2020, the Company accelerated the implementation of an ADMS ahead of the original GMP schedule. The Company was also successful with the initial implementation of VVO field equipment for the area of our system served by Townsend substation. The implementation of SCADA has been progressing as scheduled. The Company has made considerable progress towards the enhanced integration of our AMI and OMS systems. The Company made significant progress in the evaluation and project design of the field area network and mobile damage assessment projects in 2020.

The Company's coordinated deployment of these grid-facing investments will expedite the achievement of grid modernization objectives and allow the Department to more accurately assess the benefits to customers relative to the costs. 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. At many substations that presently have some level of existing SCADA capability, it is not complete to the extent intended under the GMP. 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.

Development of the first phase of the OMS integration with AMI project began in earnest in 2020 with plans for a second phase introduced early in the year. The Company has completed a functionally complete prototype, including the development of a homogeneous outage data lake with data from our AMI and OMS systems as well as cellular communication history, and we continue to test and tune the scoring algorithm. Unitil continues to research machine learning tools, data science techniques, and cloud technologies to determine the best approach for building applications that will help to determine and calculate the confidence score.

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). In some cases, voltage regulators and capacitor banks are replaced because they not able to have new controls installed. Voltage and Energy monitors (sensors) 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. The Company also made the decision to integrate VVO with ADMS as opposed to having individual systems. This approach will ensure that the ADMS and VVO systems use the same data and network models to make optimization decisions on the system. The Company identified that the VVO, ADMS, FAN and SCADA projects are closely tied together and has developed a combined project schedule for these projects and will be deployed on a substation by substation basis. The goal is that each substation will have all of the projects and functionality completed at the same time as opposed to multiple discreet efforts. The installation of VVO equipment began for the circuits served from Townsend substation in 2020.

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.

In 2020, the Company began implementation of ADMS. This included the design and development of a secure network and the transition of one Unitil substation from Unitil's existing SCADA master to the ADMS SCADA master in the test environment. In the fourth quarter of 2020 Unitil completed the modelling and implementation of unbalanced loadflow of one substation (three circuits) in the ADMS test environment.

The Company's filed GMP does not contemplate the DERMS project to be implemented until the fifth year of the plan. However, the selected ADMS has the ability to implement DERMS functionality in the future. The Company has set a priority on implementing ADMS, SCADA, FAN and VVO prior to integrating DERMS. The Company will report on further progress in future Grid Modernization Annual Reports.

Communications Investment Category

This project consists of installing a FAN, including communications between collectors and endpoint 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.

In 2020, a vendor was selected for the consulting services to assist in the specification and evaluation of proposals for a FAN throughout its electric service franchise area in Massachusetts. The following tasks were completed through the assistance of the consultant: identified the needs and requirements of the FAN, developed a specification for the network, created a list of appropriate bidders, issued an RFP to the list of bidders and completed a review and evaluation of different approaches to implementing a FAN.

The Company awarded the FAN contract to AT&T and will utilize AT&T Firstnet cellular network and the FAN backhaul. The Company went through a product evaluation of the modems that are compatible with AT&T Firstnet and have finalized the cell modems that will be used in the FAN. On 11/12/2020, the first of two Fiber backhaul circuits were ordered and the primary site Fiber backhaul has been installed. The Company is currently waiting for the second Fiber backhaul circuit to be scheduled for installation.

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 easily capture field damage and inspection information, while integrating with the work order process to improve situational awareness and the speed of restoration. This Mobile Platform - Assessment and Inspection Tool will integrate with existing systems to 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 have better understanding of their proposal and any questions answered. Following the vendor presentations, the evaluation matrix was updated by all members of the project team.

After several meetings and weeks of deliberation by the project team, it was ultimately decided that the best solution was the Mobile Information Management System (MIMS) Lifecycle proposed by SSP Innovations. The MIMS solution will be synchronized with the Company's GIS systems and is designed to perform electronic field inspections of assets and vegetation while also providing the ability to create workflows, assign and track work assignments, and estimate cost, labor and equipment associated with work orders. The Company has executed contract documentation for the project and began working with SSP to develop the solution in January 2021. Development is expected to occur throughout Q2 with an estimated final project completion date of September 2021.

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. The 2018 Plan Year represents the actual spending in 2018 and forecast spending the following years. The 2019 Plan Year represents the actual 2019 spending and forecast spending the following year. Table 1 below demonstrates the actual spending versus the plan.

	Actual/Forecasted Capital Spending			
	2018	2019	2020	2021
Monitoring and Control				
SCADA				
2019 Plan Year	$ -	$ 215,012	$ 675,614	$ 271,891
2020 Plan Year	$ -	$ 215,012	$ 608,203	$ 239,346
OMS Integration with AMI *(Note 1)*				
2019 Plan Year	$ -	$ 22,800	$ 83,200	$ -
2020 Plan Year	$ -	$ 22,800	$ 57,136	$ 50,000
Volt VAr Optimization				
VVO				
2019 Plan Year	$ -	$ 60,000	$ 2,840,000	$ 739,000
2020 Plan Year	$ -	$ 63,905	$ 1,787,195	$ 3,264,661
Advanced Distribution Management System				
ADMS *(Note 1)*				
2019 Plan Year	$ -	$ -	$ 400,000	$ 450,000
2020 Plan Year	$ -	$ -	$ 172,724	$ 425,000
DERMS *(Note 1)*				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ -	$ -	$ -
Field Area Network				
Field Area Network				
2019 Plan Year	$ -	$ 107,057	$ 280,000	$ 280,000
2020 Plan Year	$ -	$ 107,057	$ 324,556	$ 449,818
Workforce Management				
Mobile Platform Damage Assessment *(Note 1)*				
2019 Plan Year	$ -	$ -	$ 650,000	$ -
2020 Plan Year	$ -	$ -	$ -	$ 650,000
Total				
Total				
2019 Plan Year	$ -	$ 404,869	$ 4,928,814	$ 1,740,891
2020 Plan Year	$ -	$ 408,774	$ 2,949,814	$ 5,078,825

Table 1 – Planned Versus Actual Capital Spending

Note 1: This is a software project. The Company has decided to also deploy the software to the Company's affiliate in New Hampshire (Unitil Energy Systems, Inc., "UES"). Therefore, the total spending on the project will be allocated using the Company's standard allocation factors: UES – 68% and FG&E - 32%. The costs shown in the table above include all spending, not the allocated amounts.

The Company continues to work to improve our project plan and estimates as we learn more about the challenges with the technology being deployed. Delays due to the COVID-19 pandemic have affected the overall project schedule. The Company will endeavor to make up for these delays in future years. There is an increase identified in 2021 primarily driven by the timing of spending for the VVO project. The highest priority VVO circuits are also the most costly, due to the quantity of equipment to deploy. The Company believes that over the course of the program, the costs will be in line with original estimates.

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. However, since this is a software project, the Company has decided to also deploy the software to the Company's affiliate UES, so it is expected the final cost allocated to FG&E is estimated to be slightly less than the original estimate.

For the Company's VVO investment, actual spend is higher than planned throughout the 2018-2020. Unitil expects that Townsend, Lunenburg, and Summer Street are among the most expensive substations to roll VVO out along due to equipment needs, and expects costs will begin to come into line over the remainder of their 10-year planned term.

The Company's original plan contemplated ADMS spending to start in the third year of the plan. Based on the awarded vendor's proposal, the FG&E cost of the ADMS is expected to be approximately $850,000 from 2020-2022, with some additional expenditure expected in years 2023-2027 for implementation of VVO throughout FG&E's territory. In 2019, the project team created and issued an RFP for the ADMS and awarded the project in November of 2019. In 2020, the Company began implementation of ADMS. This included the design and development of a secure network and the transition of one Unitil substation from Unitil's existing SCADA master to the ADMS SCADA master in the test environment. In the fourth quarter of 2020, Unitil completed the modelling and implementation of unbalanced loadflow of one substation (three circuits) in the ADMS test environment. The Company expects the ADMS to come in on budget for the remainder of the plan. Since this is a software project, the Company has decided to deploy the software at UES as well. Therefore, the total spending on the project will be allocated using the Company's standard allocation factors. The updated estimate is still under development in conjunction with the overall design of the system. The Company expects the ADMS project spending allocated to FG&E will be less than the original estimate.

In 2019, a specification was developed and completed to request proposals (RFP) from vendors for field area network consulting services. In 2020 a vendor was selected for the consulting services to assist in the specification and evaluation of proposals for a FAN throughout its electric service franchise area in Massachusetts. The FAN project will follow the implementation of VVO and, as expected, the FAN project spending will be higher in the earlier years of the plan and less in the later years of the plan. Overall the Company expects the FAN project costs to be in line with the original estimate.

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's competitive RFP process resulted in a product that is more costly than the initial estimates. However, since this is a software project the Company has decided to deploy the software at UES as well. Therefore, the total spending on the project will be allocated using the Company's standard allocation factors. The final cost allocated to FG&E is estimated to be slightly less than the original estimate.

The Department issued a memorandum on March 11, 2021 ("Memorandum"), which adopted modifications to the reporting templates for use in future Grid Modernization Annual Reports. Section II.B of the memorandum directed each company to report capital costs and operations and maintenance ("O&M") costs as distinct components of spending in each grid modernization plan year. In addition, each company shall categorize capital costs by capitalized labor costs and non-labor capital costs. If the sum of capital costs and O&M costs is less than the total annual reported spending, the company shall explain the basis for the discrepancy.

In addition, the Department's Memorandum directed each company, as part of its 2020 Grid Modernization Annual Report filing, to provide a narrative description, including a data table, of its 2018 and 2019 spending consistent with these directives.

The Company worked collaboratively with the other EDCs to develop a common template for reporting capital costs categorized by labor costs and non-labor costs for the years 2018-2020. Reference Tab 5c of the Company's D.P.U. Appendix 1 for plan year 2020. In 2018, the Company did not incur any capital spending to be reported. In 2019, the Company incurred capital costs (both labor and non-labor) for the following projects: SCADA, AMI/OMS Integration, VVO, and FAN. These project costs were less than projected, as the projects were just getting underway. In 2020, the Company incurred costs for SCADA, AMI/OMS Integration, VVO, ADMS, and FAN. Overall the Company's spending continues to be lower than projected due to the timing of project implementation.

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 incurred some incremental O&M spending in 2019 and 2020 as provided below. 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			
	2018	2019	2020	2021
Monitoring and Control				
SCADA				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ -	$ -	$ -
OMS Integration with AMI				
2019 Plan Year	$ -	$ -	$ 1,000	$ 1,000
2020 Plan Year	$ -	$ -	-	$1,000
Volt VAr Optimization				
VVO				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ -	$ 9,051	$ 4,593
Advanced Distribution Management System				
ADMS				
2019 Plan Year	$ -	$ -	$ 100,000	$ 100,000
2020 Plan Year	$ -	$ -	$ -	$ 100,000
DERMS				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ -	$ -	$ -
Field Area Network				
Field Area Network				
2019 Plan Year	$ -	$ -	$ 100,000	$ 100,000
2020 Plan Year	$ -	$ -	$ -	$ 100,000
Workforce Management				
Mobile Platform Damage Assessment				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ -	$ -	$ -
Admin & Regulatory				
2019 Plan Year	$ -	$ -	$ -	$ -
2020 Plan Year	$ -	$ 10,625	$ 12,307	$ 20,000
Total				
Total				
2019 Plan Year	$ -	$ -	$ 201,000	$ 205,593
2020 Plan Year	$ -	$ 10,625	$ 21,358	$ 225,593

Table 2 – Planned Versus Actual Incremental O&M Spending

The Department's Memorandum adopted modifications to the reporting templates for use in future Grid Modernization Annual Reports. Section II.B of the Memorandum directed each company to report capital costs and operations and maintenance ("O&M") costs as distinct components of spending in each grid modernization plan year. In addition, each company shall categorize capital costs by capitalized labor costs and non-labor capital costs.

If the sum of capital costs and O&M costs is less than the total annual reported spending, the company shall explain the basis for the discrepancy.

In addition, the Department's Memorandum directed each company as part of its 2020 Grid Modernization Annual Report filing, to provide a narrative description, including a data table, of its 2018 and 2019 spending consistent with these directives.

The Company worked collaboratively with the other EDCs to develop a common template for reporting O&M costs for the years 2018-2020. Reference Tab 5c of the Company's D.P.U. Appendix 1 for plan year 2020. In 2018, the Company did not incur any incremental O&M spending to be reported. In 2019, the Company incurred O&M charges associated with the evaluation plan conducted by Guidehouse. In 2020, the Company incurred costs within VVO for incremental software licensing fees as well as charges associated with the evaluation plan conducted by Guidehouse. Overall the Company's O&M spending continues to be lower than projected due to the timing of project implementation.

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. Project teams have responsibility for implementing the grid modernization projects. These individuals are also the same individuals who are designing and implementing traditional investment projects. These individuals have a full understanding which projects are related to the GMP and which projects are not associated with the GMP.

The Company intends to leverage as much of its existing infrastructure and traditional investments as possible to further advance the grid. However, investments made outside of the GMP will not be included for cost recovery through the grid modernization proceedings. The Company believes this approach will help the Company to manage costs and result in an efficient implementation of the grid modernization investments. This approach will also allow the Company to differentiate between devices installed under the pre-authorized grid modernization investments and those installed under typical company investments. In some cases, when the Company does not have the experience or technical expertise, external resources will 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 3) 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, Finance and Budgeting 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 project leads are primarily focused on the design and implementation of their particular project. The project leads provide updates on their individual projects at the Steering Committee meetings as well as provide updates and data for this report.

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. The Company will be filing a GMF to recover costs incurred on grid modernization projects in 2020.

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 Director of Finance. 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 VVO Remote Measurement Sensors
Advanced Distribution Management System	ADMS
	DERMS
Communications	Field Area Network
Workforce Management	Mobile Platform Damage Assessment

Table 3 – GMP Investments by Investment Category

The Department also ordered the Distribution Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the Distribution Companies' preauthorized grid modernization plan investments and their progress toward meeting the Department's grid modernization objectives. D.P.U. 15-122, at 204-205. Guidehouse (formerly Navigant Consulting, Inc.) is completing the evaluation to ensure a uniform statewide approach and to facilitate coordination and comparability across the Distribution Companies. On December 1, 2020, the EDCs, along with Guidehouse, filed revised Stage 3 Evaluation Plans for the GMP valuation, consistent with the order issued by the Department in D.P.U. 15-120/15-121/15-122 at 204-205 (2018). The Companies and Guidehouse updated the State 3 Evaluation Plans to accommodate the Department's extension of the 2018-2020 GMP term through 2021. D.P.U. 15-120/15-121/15-122 at 4-7 (2020). The Companies, along with Guidehouse, expect the Massachusetts Grid Modernization Program Year 2020 Evaluation for 1) monitoring and control, 2) communications, 3) advanced distribution automation, 4) VVO, 5) workforce management, and 6) ADMS and ALF investments to be issued in June 2021.

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 VVO Remote Measurement Sensors
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.

[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.

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 Street	0.76	0.71	0.43	0.76	0.53	0.65
West Townsend	0.68	1.00	0.50	0.44	0.78	0.65
Beech Street	1.00	0.79	0.13	0.62	0.51	0.63
Pleasant Street	0.77	0.74	0.50	0.45	0.68	0.62
Princeton Road	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 Street	0.59	0.30	0.00	0.34	0.46	0.39
River Street	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 from 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 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.

In 2019, the first two substation SCADA projects commenced following the GMP Order. The SCADA additions at one of these two substations (Rindge Road substation) was placed into service at the end of 2019, and the SCADA additions at the second substation (Townsend substation) was placed into service in February 2020. As part of the continuing SCADA deployment under the Company's GMP, SCADA additions and modifications were then completed in 2020 at two more substations (Beech Street and Lunenburg substations).

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

Table 7 provides the actual versus planned implementation and spending. The 2019 Plan Year represents the actual spending in 2019 and forecast spending the following years. The 2020 Plan Year represents the actual 2020 spending and forecast spending the following year. 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 2021			
SCADA	2018	2019	2020	2021
2019 Plan Year	$ -	$ 215,012	$ 675,614	$ 271,891
2020 Plan Year	$ -	$ 215,012	$ 608,203	$ 239,346

<u>Table 7 – SCADA Capital Spending Estimates</u>

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 resulted in a levelized 10 year plan with an annual estimate of $100,000 per year or $1.0 million total. The present estimate totaling approximately $2.2 million shown in Table 8 identifies the cost estimates to install SCADA at each substation.

	Cost Estimates by Substation at Planned Years of Completion[2]						
Substation	2018	2019	2020	2021	2022	2023	2024
Beech Street	$ 0		$ 90,877				
Canton Street					$ 625,240		
Lunenburg	$ 0		$ 132,416				
Nockege							$ 218,131
Pleasant Street	$ 0						
Princeton Road	$ 0			$ 239,346			
Rindge Road		$ 1,700	$ 5,221				
River Street						$ 186,102	
Sawyer Passway							
Summer Street			$ 0				
Townsend		$ 213,312	$ 379,689				
Wallace Road		$ 0					
West Townsend	$ 0						

Table 8 – SCADA Schedule and Capital Cost Estimate

The cost increases relative to the original plan 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.

[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.

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

Full SCADA implementation was placed into service for Townsend, Beech Street and Lunenburg substations in 2020. Full SCADA implementation is planned to be completed for Princeton Road substation in 2021.

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

This is a software project to enhance the current AMI to OMS interface. Unitil has already implemented an AMI system across its service territories. This enhanced integration will provide improved ability for all AMI meters to communicate with the OMS system in a more reliable manner resulting in greater confidence in the data presented. This enhanced data will be used in the OMS outage engine to help improve outage predictions, including which device has isolated the fault and what customers have been restored.

Unitil'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.

Unitil's OMS system relies on customer outage calls processed by the IVR system, web outage form entries, and manual entries of customer and municipal calls to determine the location and extent of outages. Most outages are reported by only a small percentage of customers contributing to the outage information (typically, only 1-2% of the customers notify Unitil when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.

Unitil's AMI system is currently integrated with OMS as a "view only" overlay. The AMI system communicates with all meters through a parallel channel power line carrier (PLC) system. Essentially, the system continuously communicates with all the meters on the system while data collectors in the substations transmit meter status to the head end software system called the Command Center. Changes in meter status are shared through live integration with the OMS where they can be represented visually. Because communication with meters could be lost for reasons other than an outage (e.g., noise on power line, loss of AMI network communications), Unitil does not use this information in the algorithm for modeling outages in OMS. Instead, the visual AMI information is presented in OMS to help determine the extent of the outage (i.e. all outage meters go "lost" or red when they lose power) and the extent of restoration (i.e. all restored meters restored become "found" or green).

The figure below shows a partial restoration of an outage. The red icons indicate customers still out, the green are customers that have been restored.

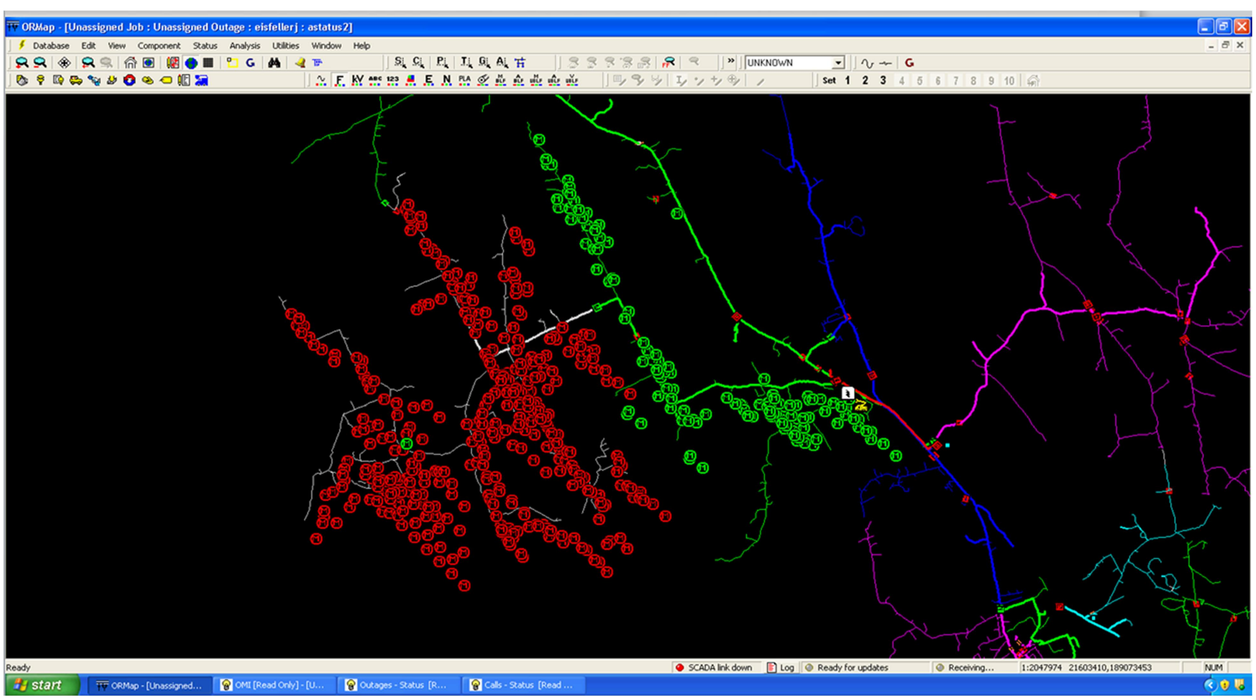

Figure 1: Unitil's AMI Meters in OMS

Unitil 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 "confidence 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. This threshold is adjustable by the dispatcher to allow some level of active customization.

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

Unitil has 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 project has been broken down into two phases (both are included in the project):

Phase 1 – AMI Confidence Engine & Filter

Although our Landis and Gyr AMI system has functionality to detect and report on meter/ endpoint level outages, the results we see are unreliable to the point that Unitil has chosen not to directly integrate the AMI data for outage model calculations. A meter black list construct was implemented where known bad reporting endpoints could be grouped and ignored by any auto outage detection. However, there is no easy way for Unitil to dynamically move meters on and off this "outage reporting black list", which makes it a largely static list. If, for example, we make improvements to a network segment of previous blacklisted meters; even though these meters could likely better participate in the AMI auto detection after the upgrade is completed, they will not be able to, because they are part of this hardcoded black list.

Unitil is making use of this automatic detection process and accompanying data in an effort to improve our ability to detect and respond to customer outages. Unitil also believes that it can augment the existing Landis & Gyr detection algorithm with an additional algorithm leveraging readily available data to correlate and further qualify (by way of a "Confidence Score") suspected outages.

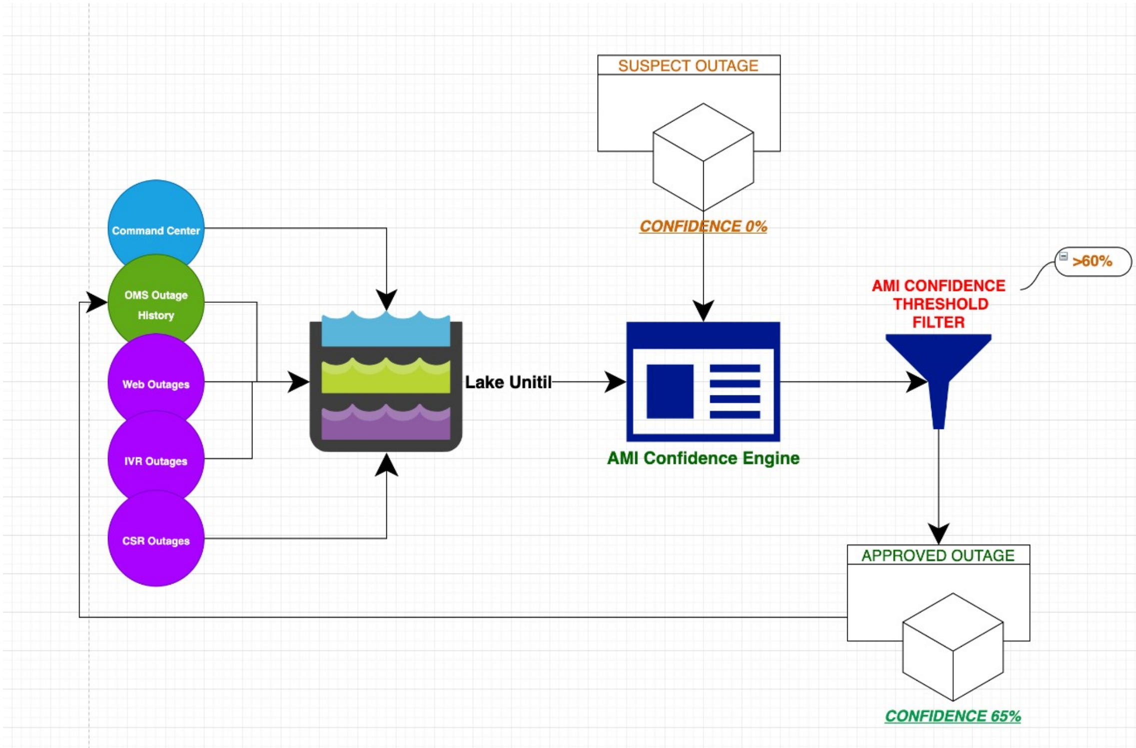

Figure 2: AMI/OMS Phase 1 Diagram

ACE Filter - The ACE Filter is a software service that is responsible for evaluating the confidence score attached to an outage and determining if the score meets or exceeds the configurable confidence threshold (dispatchers would be able to dynamically adjust this threshold up or down). Any outage that meets or exceeds the threshold is allowed through the Filter. Any outage failing to meet the criteria is rejected, logged and a notification is sent. No changes would be required to the core OMS functionality as the filter would handle pre- screening outages before sending them along to OMS.

Lake Unitil - Our data warehousing "lake", will contain data from our Command Center, OMS and enQuesta systems to start. The application development team will build out data load scripts to populate and maintain this Data Lake. It is helpful to think of a data lake as a large data warehouse in the cloud that contains data in a variety of different formats (*XML, flat unstructured data files, CSV and traditional relational data). The ACE will use the data contained in this lake to make its confidence scoring decisions. In later phases, additional data points such as vegetation, social media, behind the meter status and weather could be added to the data lake and augment the algorithm.

Phase 2 – Additional Data Sources

In this phase of the development we will be including additional data sources into the confidence interval. Specifically, this plan includes the collection and combination of data sources for weather as well as signal to noise ratio (directly from AMI Collectors) into the confidence engine. Quality control, testing and deployment, as well as ongoing support of the system are included.

Project Summary

This project will combine AMI status information, modem status information, and current outage input data (IVR, Web, and manual entries), and process this information through a series of software filters and logic to allow AMI information to be used in the outage algorithm. The goal will be to develop this filter to the point at which there is high confidence in the result (i.e., the AMI status change is a result of an actual outage). If a high confidence is achieved, the AMI data will allow Unitil to determine the probable location and extent of an outage in a shorter timeframe, resulting in improvements in outage response time estimates and related customer communications.

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.

3.1.1.2.1 Description of Work Completed

Development of the 1[in] phase of the project began in earnest in 2020 with plans for a second phase introduced early in the year. The company has completed a functionally complete prototype and continues to test and tune the algorithm.

Unitil continues to research machine learning tools, data science techniques, and cloud technologies to determine the best approach for building 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.

	Overall Project Estimate Through 2021			
OMS Integration with AMI	2018	2019	2020	2021
2019 Plan Year	$ -	$ 22,800	$ 83,200	$ -
2020 Plan Year	$ -	$ 22,800	$ 57,136	$50,000

Table 9 – OMS Integration with AMI Capital Spending Estimates

The costs shown in the table above include the total estimated costs. Since this is a software project the Company has decided to deploy the software to the Company's affiliate in New Hampshire (Unitil Energy Systems, Inc., "UES"). Therefore, the total spending on the project will be allocated using the Company's standard allocation factors.

The increase in estimated costs associated with this project is 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 for 10% of outages.

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 2021, testing of the middleware application for accuracy and completeness is ongoing. In addition, user interface work is being completed on a dashboard and reporting web application. Additional data points, including data from the actual AMI collectors will be integrated into the project this year rounding out the second phase. Unitil plans to be live with this system in 2021.

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.

3.1.3.1 VOLT/VAR OPTIMIZATION (VVO)

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 materials for the all the circuits emanating from the first two substations have been ordered. The material list for the circuits from the third substation has been created and the material is planned to be ordered this year. The Company plans to incorporate the installation of controls one substation per year, detailed below. Installation of

distribution equipment for the first two substations is planned this year, with full implementation of the central analysis and control through the ADMS system for the first substation (Townsend) this year.

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 evaluated two basic approaches to implementing a VVO system: model based and measurement based) and then it was decided that a model based system would be implemented through integration with ADMS.

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.

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 replace necessary voltage regulators and install the required controls on the remaining voltage regulators, transformer LTC's, and capacitor banks. In addition new remote measurement sensors will be installed at strategic locations. VVO functionality will be implemented on all distribution circuits as proposed in its GMP. The VVO functionality will be implemented by a central ADMS through the installation of remote communication (SCADA) system.

Through detailed analysis, the Company had adjusted the design of required installations and has revised the project estimate as listed below. The original plan based the cost estimates based on average number of regulators and capacitor banks per circuit. The revised plan cost estimate is specific to the individual circuits planned for each year. After the original plan was created, the Company decided to perform the VVO functionality through the ADMS. The implementation plan was delayed until the ADMS was specified.

	Overall Project Estimate Through 2021			
VVO	2018	2019	2020	2021
2019 Plan Year	$ -	$ 60,000	$2,840,000	$ 739,000
2020 Plan Year	$ -	$ 63,905	$ 1,787,195	$ 3,264,661

Table 10 – VVO Capital Spending Estimates

3.1.3.1.4 Performance on Implementation/Deployment

After investigation of functionality of the ADMS, the equipment specification and purchasing of the VVO project commenced in 2019. Although some spending has been committed and paid, the functionality has not yet been installed and implemented. The implementation of VVO functionality is planned to be performed on circuits related to one substation each year. The plan includes completing VVO functionality through the ADMS at the Townsend Substation in 2020. The implementation of VVO functionality on circuits emanating from the Lunenburg and Summer St. substations is planned in 2021. 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 thereby 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 existing field devices and 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. In addition to the existing devices, new installations of monitors and new voltage regulators are planned. The actual number of additional devices is determined 1-2 years prior to the planned installation. Until the actual number of additional devices is determined, an estimate is included based on the circuit size. The year listed below indicates the expected year that the equipment will be installed and VVO implemented.

Year	Substation	LTC Controls	Volt Reg Controls[3]	Cap Bank Controls	Monitors[4]

[3]Unitil detailed analysis is performed for a given year, the number of voltage regulator controls listed is only the present number installed on the system. Detailed analysis is performed a year prior to planned installation which will identify the quantity of regulators required.

2022	Townsend	1	6	4	12
2022	Lunenburg	0	21	4	23
2023	Summer Street	1	16	4	26
2023	West Townsend	1	11	6	14
2024	Beech Street	1	0	6	6
2025	Pleasant Street	1	11	10	14
2025	Princeton Road	2	1	7	4
2026	Sawyer Passway	2	19	1	18
2026	Nockege	1	8	1	0
2027	Canton Street	2	6	6	10
2028	River Street	1	5	7	7
2029	Rindge Road	0	10	0	6

Table 11 – VVO Field Equipment Estimates

3.1.3.1.8 Updated Projections for Remainder of the Three-year Term

In 2020-2022, the Company plans to:

- Complete the installation and implementation on the initial ADMS circuits to determine any unplanned adjustments.
- Continue installation of the controls and monitors on all circuits emanating from four substations per 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. The DERMS functionality is available in the ADMS system the Company is implementing.

3.1.4.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

This project will consist of upgrading the Company's current OMS to an ADMS that will support VVO and power flow analysis. In the future the AMDS will also support 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 DERMS. The existing system integrations with GIS,

[4] Unitil detailed analysis is performed for a given year, the number of monitors listed is only the present number installed on the system. Detailed analysis is performed a year prior to planned installation.

CIS, OMS and SCADA will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

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, unbalanced 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 made decision to utilize ADMS as the central VVO controller and began work in 2018 by assigning an internal project manager and assembled a project team of internal employees.

In 2019, the project team created and issued an RFP for the ADMS and awarded the project in November of 2019. Based on the evaluation the decision was made to upgrade the Company's current OMS to ADMS instead of purchasing and implementing a new system.

In 2020, the Company began implementation of ADMS. This included the design and development of a secure network and the transition of one Unitil substation from Unitil's existing SCADA master to the ADMS SCADA master in the test environment. In the fourth quarter of 2020 Unitil completed the modelling and implementation of unbalanced loadflow of one substation (three circuits) in the ADMS test environment.

Unitil is planning to go-live with ADMS in the production environment in the second quarter of 2021 and complete the modelling and implementation of unbalanced loadflow on two additional substations (six circuits) in 2021. Additionally, the implementation of the ADMS switch order module is expected to begin in 2021. Full deployment of the FG&E ADMS is expected to be completed by the end of 2022 with VVO deployment following the VVO schedule.

3.1.4.1.2 Lessons Learned/Challenges and Successes

Based on information gathered in 2018 and 2019 the Company elected to upgrade its current OMS to an ADMS and implement a modelled based system that utilizes field measure to "tune" and verify the model. The system has the ability to be transitioned to a measurement based system in the future.

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.

The Company has also learned that the ADMS model will required a significant amount of technical data and customer generator and load profile information to provide accurate model results. Unitil is currently in the process of gathering this information and working to enhance the current OMS integrations with existing systems (GIS, OMS, CIS, and SCADA) to supply the necessary information to ADMS.

In addition, the Company has learned that as more "dispatchable" technologies (energy storage systems, electric vehicles, etc.) are added to the distribution system the need for additional real-time metering and the possible switch to a measurement based system could be required due to the lack of historical trends and the unpredictable nature of these technologies.

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 developed an RFP and awarded the ADMS project in 2019. The Company is currently working to developing a test ADMS and is expected to "go-live" with the first three circuits in late 2020. Based on the award vendor's proposal the FG&E cost of the ADMS is expected to be approximately $850,000 from 2020-2022 (as opposed to $2.1 million) with additional expenditures expected in years 2023-2027 for implementation of VVO throughout the FG&E territory.

	Overall Project Estimate Through 2021			
ADMS	2018	2019	2020	2021
2019 Plan Year	$ -	$ -	$ 400,000	$ 450,000
2020 Plan Year	$ -	$ -	$ 172,724	$ 425,000

<u>Table 12 – ADMS Capital Spending Estimates</u>

3.1.4.1.4 Performance on Implementation/Deployment

This project got underway in 2019. Unitil implemented an ADMS test system and modelled and implemented one unbalanced loadflow on one substation and three circuits in 2020. Two additional substations and six circuits are planned in 2021. The remaining substations and circuits will be modelled in ADMS in 2022 and integrated with the available SCADA sites. The remaining integration of SCADA and VVO will be per the schedules of those projects.

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 feeders and substations by similar amounts. 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 company's current OMS system will be upgraded to provide the following:

- GIS integration enhancement to transfer the network model technical data from the GIS system to the ADMS system on a routine basis as changes to the network topology are made in GIS
- SCADA system enhancement to provide necessary equipment status, control and telemetry to ADMS
- New process to provide ADMS customer load profile and generator output information.
- 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
- Hot standby fault recovery

3.1.4.1.7 Key Milestones

Below are some of the key milestones for the deployment of the Company's ADMS. The company is currently on schedule to meet these milestones.

- 5/7/2021 – ADMS Production System Build Complete
- 7/12/2021 – Lunenburg Unbalanced Loadflow Implementation Complete
- 12/1/2021 – Summer Street Unbalanced Loadflow Implementation Complete
- 1/30/2022 – West Townsend Ready for VVO Control
- 7/1/2022 – Switch Order Module Implementation Complete
- 10/30/2022 – Remainder of FG&E System modelled in ADMS (per available SCADA/VVO capabilities)
- 12/30/2022 – Manual Load Shed and System Power Factor Algorithms Implemented
-

3.1.4.1.8 Updated Projections for Remainder of the Three-year Term

Implementation began in 2020 with full integration of existing systems with all FG&E circuits being modelled in ADMS by the end of 2022. Additional VVO deployment utilizing ADMS will follow the ADMS and SCADA schedules. This also includes the implementation of VVO on circuits that have controls and sensors capable of VVO. FLISR will be implemented on the circuits that have the necessary SCADA information to utilize this functionality.

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 will be implemented as a module to the ADMS the company is in the process of implementing. 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 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

In 2019, a specification was developed and completed to request proposals (RFP) from vendors for field area network consulting services. In 2020 a vendor was selected for the consulting services to assist in the specification and evaluation of proposals for a FAN throughout its electric service franchise area in Massachusetts. The following tasks were completed through the assistance of this consultant: identified the needs and requirements of the FAN, developed a specification for the network, created a list of appropriate bidders, issued an RFP to the list of bidders and completed a review and evaluation of different approaches to implementing a FAN.

Unitil evaluated several options of building a radio frequency (RF) communications network in addition to partnering with an existing carrier s. Based upon the bidding evaluation, Unitil decided on the carrier solution for our field communications.

The Company awarded the FAN contract to AT&T and will utilize AT&T Firstnet cellular network and the FAN backhaul. The Company went through a product evaluation of the modems that are compatible with AT&T Firstnet and have finalized the cell modems that will be used in the FAN. On 11/12/2020 the first of two Fiber backhaul circuits were ordered and the primary site Fiber backhaul has been installed. The Company is currently waiting for the second Fiber backhaul circuit to be scheduled for installation.

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 a common schedule has now been created for the FAN, ADMS, VVO and SCADA.

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 has updated its estimates and project plan to coincide with SCADA and VVO projects.

	Overall Project Estimate Through 2021			
Field Area Network	2018	2019	2020	2021
2019 Plan Year	$ -	$ 107,057	$ 280,000	$ 280,000
2020 Plan Year	$ -	$ 107,057	$ 324,556	$ 449,818

Table 13 – FAN Capital Spending Estimates

3.1.5.1.4 Performance on Implementation/Deployment

To date, the FAN modem order has been placed; the Primary backhaul circuit has been installed; and the Company is waiting for the Secondary backhaul circuit schedule. The FAN secure access environment has been built at the primary site in Exeter NH. The focus in 2021 is to install cell modems along with implementation of VVO and SCADA.

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

Below are some of the key milestones for the deployment of the FAN. The company is currently on schedule to meet these milestones.

- 3/31/2020 RFP Proposals due
- 4/23/2020 Award vendor
- 5/14/2020 Project initiated, design work begins
- 9/1/2020 Substation 1 Field Installation
- 11/12/2020 Primary FAN backhaul circuit installed
- Cell Modems will be installed according to the VVO and SCADA implementations

3.1.5.1.8 Updated Projections for Remainder of the Three-year Term

The Company has awarded the FAN solution contract to AT&T utilizing AT&T Firstnet cellular network, including an AT&T fiber backhaul to the Company's primary and secondary data center locations. Cell Modems will be installed according to the VVO and SCADA implementations.

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 and asset inspections integrated with a 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 faster and more accurate 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 team developed an RFP and received proposals from 13 vendors.

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.

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

After the initial review and evaluation, several vendors were invited into the Company to provide a presentation on their proposal so that the project team could a clearer understanding of their proposal and have questions answered. Following the vendor presentations, the evaluation matrix was updated.

After several meetings and weeks of deliberation by the project team, it was ultimately decided that the best solution was the Mobile Information Management System (MIMS) Lifecycle proposed by SSP Innovations. The MIMS solution will be synchronized with the Company's GIS systems and is designed to perform electronic field inspections of assets and vegetation while also providing the ability to create workflows, assign and track work assignments, and estimate cost, labor and equipment associated with work orders. The Company completed review of the statement of work and contract documentation and began this project in late Q1 of 2020. The kickoff of this project was delayed by the COVID-19 pandemic.

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 this software platforms can provide. Other functionality includes asset management, inspections, or other workforce management tools with several proposals including many of these features included within their products. The Company is interested in additional functionality in the future and has included the additional functionality available from the vendor offerings during their evaluation.

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

The project team has identified a cost increase in this project. 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.).

	Overall Project Estimate Through 2021			
Mobile Platform Damage Assessment	2018	2019	2020	2021
2019 Plan Year	$ -	$ -	$ 650,000	$ -
2020 Plan Year	$ -	$ -	$ -	$ 650,000

Table 15 – Mobile Platform Damage Assessment Capital Spending Estimates

The costs shown in the table above include the total estimated costs. Since this is a software project the Company has decided to deploy the software to the Company's affiliate in New Hampshire (Unitil Energy Systems, Inc., "UES"). Therefore, the total spending on the project will be allocated using the Company's standard allocation factors and the cost allocated to FG&E is expected to be less than the original estimate.

3.1.6.1.4 Performance on Implementation/Deployment

The Company completed its review of the statement of work and execution of contract documentation and begin this project in January of 2021. The Company expects development to take place through Q2 with final project completion estimated in September 2021. 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 existing paper based damage assessment and inspections 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 be transferred back to the back end system portal in the office where ETRs and work packages can be developed, issued for repair, tracked until completion.

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 has completed its review and evaluation of all proposals and has selected a solution to move forward. The Company is currently reviewing statement of work and contract documentation with the vendor (SSP Innovations). The Company has executed contract documentation for the project and began working with SSP to develop the solution in January 2021. Development is expected to occur throughout Q2 with an estimated final project completion date of September.

3.1.6.1.8 Updated Projections for Remainder of the Three-year Term

The projections are shown in the table above. 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, the AMI system will provide outage information for use by the OMS outage prediction engine.

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 Street	1W1 1W2 1W4 1W6	LTC control & partial SCADA completed 2018 (DG interconnection project w/ full customer contribution). Full SCADA completed in 2020 as Grid Mod project; includes: (3) recloser controls, (1) meter.
Canton Street	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 (DG interconnection & DA projects) Full SCADA completed in 2020 as Grid Mod project; includes: (1) meter; integration of (2) breaker/recloser controls.
Nockege	20W22	SCADA planned for 2024 as Grid Mod project; includes: (1) recloser.
Pleasant Street	31W34 31W37 31W38	New LTC transformer & SCADA completed 2018 (Transformer Replacement & DA projects).
Princeton Road	50W51 50W53 50W55 50W56	Partial SCADA completed 2018 (SCADA System Replacement project). Full SCADA planned for 2021 as Grid Mod project.
Rindge Road	35W36	Full SCADA placed into service in 2019 as Grid Mod project.

River Street	25W27 25W28	Pre-existing partial SCADA, LTC control & full SCADA planned for 2023 as Grid Mod project; includes: (2) recloser, (1) LTC control
Sawyer Passway	22W1 22W2 22W3 22W8 22W10 22W11 22W12 22W17	Pre-existing SCADA. Possible future modifications for energy measurements for Grid Mod metrics.
Summer Street	40W38 40W39 40W40 40W42	Pre-existing partial SCADA. Full SCADA completed in 2020 (B123, 1303 and 1309 replacement project, non-GMP).
Townsend	15W15 15W16 15W17	LTC control & SCADA completed February 2020 as Grid Mod project; includes: (4) reclosers, (1) LTC control, (1) meter.
Wallace Road	1341	SCADA completed 2019 (1341A & 1341B replacement project).
West 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

The Company has installed VVO devices (regulators and capacitor banks) for the for the Townsend, Lunenburg, and Summer St. circuits. The line sensors, controls and communications to the ADMS system are planned to be implemented in 2021. The installation of all VVO devices including communications for West Townsend circuits are planned for 2021. After commissioning of VVO devices, testing will be performed in the ADMS system for about 9 months. 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 Field Devices Commissioned	Year Fully Deployed with ADMS
Townsend	15W15 15W16 15W17	2021	2021
Lunenburg	30W30 30W31	2021	2021
Summer Street	40W38 40W39 40W40 40W42	2021	2022
West Townsend	39W18 39W19	2022	2022

Table 17 – VVO Schedule Through 2021

3.2.3.1.2 Feeder Level Lessons Learned/Challenges and Successes

One of the biggest challenges facing the Company was to decide whether to implement a VVO system using a model based or measurement based approach. Due to the amount of real-time information required for a measurement based system, it has been decided to implement a model based system.

The Company has learned how critical a communications system is to the VVO, SCADA, and ADMS system. At this point a delay in the communication system implementation has delayed the construction of the VVO project.

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 in the VVO section.

<table>
<tr><th>Substation</th><th>Circuits</th><th>Year</th></tr>
<tr><td>Townsend</td><td>15W15
15W16
15W17</td><td>2020</td></tr>
<tr><td>Lunenburg</td><td>30W30
30W31</td><td rowspan="3">2021</td></tr>
<tr><td>Summer Street</td><td>40W38
40W39
40W40
40W42</td></tr>
<tr><td>West Townsend</td><td>39W18
39W19</td></tr>
<tr><td>Remaining FG&E Substations (modelled)</td><td>Remaining Circuits (modelled)</td><td>2023
(VVO/SCADA will be deployed per their project scheduled)</td></tr>
</table>

Table 18 – ADMS Schedule Through 2023

3.2.4.1.2 Feeder Level Lessons Learned/Challenges and Successes

The biggest challenges facing the Company at this point are 1) gathering and modifying GIS to provide all the necessary technical data and substation/subtransmission information to ADMS; 2) Developing hourly load profile and generator output data for all customers and generators on the system; 3) Improved integration between OMS/ADMS and SCADA to provide the necessary "real-time" controls and metering information; 4) Implementation schedule of the VVO and FAN projects.

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 can be implemented as a module within the ADMS 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. The Company will begin deploying communications equipment in 2021 beginning with the Townsend substation circuits.

3.2.5.1 FIELD AREA NETWORK

This project consists of installing a FAN including communications 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 as ADMS, VVO and SCADA. The company is currently in the procurement phase with an RFP published to the market, in order to support the deployment of the FAN.

3.2.5.1.2 Feeder Level Lessons Learned/Challenges and Successes

As described above, there is a schedule for the order of substation and feeder deployment over the coming years.

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 includes a mobility platform for storm damage assessment and asset inspections integrated with a 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 DISTRIBUTED GENERATION FACILITIES

One of the primary objectives of grid modernization is to facilitate the interconnection of distributed energy resources ("DER") and to integrate these resources into 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. Reference Tab 3 Feeder Status in Appendix 1 - DPU Template for the breakdown of grid connected distributed generation facilities interconnected.

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 2020 was calculated at 457.9. Reference Appendix 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 baseline and results for the number and percentage of circuits with installed sensors. The table below summarizes the results.

	2017 Baseline	2020 Actual
Total number of Substations/Transformers	13	13
Total number of Substations/Transformers with Sensors	13	13
% of Substation/Transformers with Sensors	100%	100.0%
Total number of Circuits	45	45
Total number of Circuits with Sensors	34	40
% of Substation/Transformers with Sensors	75.5%	88.9%

Table 21 – Number/Percentage of Circuits with Installed Sensors

Appendix 3 provides the details 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 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[5]	10	9	111%
OMS Integration with AMI[6]	0	1	0%
Volt/VAr Optimization			
VVO Capacitor Banks	0	12	0%
VVO Automated Voltage Regulators	2	43	0%
VVO Automated LTC	1	1	100%
Monitoring[7]	0	61	0%
ADMS			
ADMS	0	1	0%
DERMS	Under Review	Under Review	Under Review
Communications			
Field Area Network	0	Devices based upon VVO and SCADA Deployments	0%
Workforce Management			
Mobile Platform Damage Assessment[8]	0	1	0%

5 SCADA quantities listed here are the number of circuits with Grid Mod devices that include SCADA.
6 OMS Integration with AMI is a software project.
7 Monitoring not included as a specific project but required for VVO to effectively operate
8 Mobile Platform Damage Assessment is a software project.

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.

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.

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 Total Cost of Devices Planned is the costs incurred to date. 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	$608,203	$675,614	90%
OMS Integration with AMI	$79,900	$129,900	62%
Volt/VAr Optimization			
VVO Capacitor Banks	0	$ 945,752	0%
VVO Automated Voltage Regulators	0	$ 454,816	0%
VVO Automated LTC	$22,713	$ 22,713	45%
Monitoring	0	$ 286,962	0%
Advanced Distribution Management System			
ADMS	$172,724	$850,000	20%

DERMS	0	$650,000	0%
Communications			
Field Area Network	$431,656	$2,800,000	15%
Workforce Management			
Mobile Platform Damage Assessment	0	$650,000	0%

Table 23 – Total Capital 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.

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 made some good progress towards implementation grid modernization investments in 2020. 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. As a result, much of 2018 and 2019 was used to evaluate vendors and conduct competitive bidding for the projects.

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 2021. In some cases, where planned installation was not complete in the prior year(s) the number of devices listed includes those devices that were not complete previously and are expected to be complete in the following year.

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[9]	3	$239,346
OMS Integration with AMI	1	$50,000
Volt/VAr Optimization		
VVO Capacitor Banks	18	$678,500
VVO Automated Voltage Regulators	54	$ 1,488,000
VVO Automated LTC	2	$20,000
Monitoring	75	$1,331,500
Advanced Distribution Management System		
ADMS	0	$400,000
DERMS	Under Review	Under Review
Communications		
Field Area Network	120	$449,818.00
Workforce Management		
Mobile Platform Damage Assessment	1	$650,000

Table 24 – Projected Deployment Through 2021

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 ground-fault overvoltage protection schemes that enable an increased quantity and capacity of DERs to interconnect. However, the Department's order did not approve these ground-fault overvoltage protection 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 ground-fault

[9] SCADA quantities listed here are the number of circuits with Grid Mod devices that include SCADA.

overvoltage protection. The Company currently has 4 distribution substations experiencing these conditions and additional substations are expected to require the protection scheme within a year, with the present projection of DER.

On May 22, 2019, the Department opened an inquiry (D.P.U. 19-55) to investigate the interconnection of Distributed Generation in Massachusetts, pursuant to the Standards for Interconnection of Distributed Generation ("DG Interconnection Tariff").

On December 26, 2019, the Department issued a follow-up memorandum and noted that under current Massachusetts interconnection procedures, costs related to infrastructure modification arising due to the requirements of an interconnecting DG facility are allocated to the DG facility based upon the ratemaking principle that the DG facility causing the need for a modification must pay for the modification ("the DG Cost Causation Principle"). The memorandum also included a straw proposal developed by staff to address key management of high-volume ques issues raised by stakeholders and invited comments on the straw proposal.

On February 28, 2020, following comments and a technical session on the straw proposal, the Department issued interim guidance on energy storage systems. After more written comments, the Department issued order 19-55-A which expands the interconnection ombudsperson role through establishment of a distribution generation and clean energy ombudsperson as defined. The Department issued order 19-55-B on June 23, 2020, following more rounds of comments, which provided interim guidance on interconnection for qualifying facilities. The Department issued order 19-55-C on August 6, 2020, following more rounds of comments, which issued guidelines for affected system operator studies. On September 16, 2020, the Department issued Order 19-55-D on the management of high-volume queues.

On October 22, 2020, the Department opened docket 20-75 proposing a new process for long term planning of distributed energy resources and cost recovery of system modifications required for installation of DER. The Department requested comments to the DER planning proposal attached to the order. Initial comments were filed on December 23, 2020 and reply comments were filed on February 5, 2021.

Dockets 19-55 and 20-75 continues to be very active. The Company looks forward to continuing the collaborative approach between the Department, electric distribution companies and other interested stakeholders to develop an efficient process that meets the needs of all stakeholders.

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 2020, Unitil has 1,911 customer owned DER facilities and 1 utility owned solar facility. Of the customer facilities, 1902 (99.5%) are solar and 5 are solar with battery storage. The remaining consists of 4 gas turbines and 1 wood fired turbine. The total capacity of the solar (only) units is 40,449 kVA; approximately 45% of the 2020 system peak load of 89,546 kVA. The 2020 minimum daytime load, of the FG&E system experience at the 115 kV interface, due to DER, was 4,964 kVA.

In addition to the facilities on-line, there were 157 facilities being processed for installation totaling an additional 9,812 kVA. Of these facilities in process, 2,4,28 are solar and 7,356 are solar with battery storage. .

67% of the substations 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 Company is working with the Department and other stakeholders in D.P.U. 20-75 to develop an approach for identifying and quantifying the upgrades necessary to facilitate the interconnection of DERS.

6 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.

On January 10, 2019, the Department requested comments on the appropriate form and content of the annual report to be submitted by the Companies. Additionally the Department requested comments on the reporting template. The Companies and other interested stakeholders filed comments on February 6, 2019. On March 13th the Department held a technical conference regarding the Grid Modernization Annual Reports. Additionally, the Companies responded DOER's February 20, 2019 reply comments.

On March 29th, issued an order approving the Grid Modernization Annual Report Outline/Table of Contents and extended the deadline for submission of Grid Modernization Annual Reports for plan year 2018 until May 1, 2019. On May 1, 2019, the Company issued its 2018 Annual Grid Modernization Report.

On December 6, 2019, the Department issued an Order adopting the Grid Modernization Annual Report templates and required the Companies to file subsequent Annual Reports with (1) functional versions of the approved templates and (2) the outline for the narrative sections approved on May 29, 2019. The Department also required the Companies to file a supplemental 2018 Grid Modernization Annual Report to address the changes in the approved templates. On January 31, 2020, the Company filed a supplemental 2018 Grid Modernization Annual Report template.

On March 11, 2021, the Department issued a hearing officer memorandum to implement modifications to the reporting templates, for use in future Grid Modernization Annual Reports. The Department directed the distribution companies to coordinate to ensure formatting consistency with respect to the modifications to the reporting templates. The modifications will give the Department and stakeholders the ability to more easily cross reference and compare each company's progress in implementing its Grid Modernization Plan.

In addition, the Department also ordered the Distribution Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the Distribution Companies' preauthorized grid modernization plan investments and their progress toward meeting the Department's grid modernization objectives. D.P.U. 15-122, at 204-205. Guidehouse (formerly Navigant Consulting, Inc.) is completing the evaluation to ensure a uniform statewide approach and to facilitate coordination and comparability across the Distribution Companies. On December 1, 2020, the EDC along with Guidehouse filed revised Stage 3 Evaluation Plans for the GMP valuation, consistent with the order issued by the Department in D.P.U. 15-120/15-121/15-122 at 204-205 (2018). The Companies and Guidehouse updated the State 3 Evaluation Plans to accommodate the Department's extension of the 2018-2020 GMP term through 2021. D.P.U. 15-120/15-121/15-122 at 4-7 (2020). The Companies along with Guidehouse expect the Massachusetts Grid Modernization Program Year 2020 Evaluation for 1) monitoring and control, 2) communications, 3) advanced distribution automation, 4) VVO, 5) workforce management, and 6) ADMS and ALF investments to be issued in June 2021.

In compliance with the Department's Order, the Company has included the 2020 Grid Modernization Annual Report Template as Appendix 1 to this report.

7 RESEARCH, DESIGN AND DEVELOPMENT

The Company continues its RD&D activities focused primarily around (1) identification and evaluation of non-wires alternative projects and (2) strategic vision teams tasked with developing a roadmap to guide the Company's incremental investments over time. At the present time the Company has not identified any RD&D projects that it is requesting to include in the Company's Grid Modernization plan.

7.1 NON-WIRES ALTERNATIVES

The Company has implemented a utility scale PV installation and in currently in the process of installing a utility scale battery storage system. The Company has implemented a non-wires RFP process into its annual planning procedure and has activated that procedure for a project in UES (NH affiliate distribution company) to evaluate non-wires alternatives. The Company will continue to evaluate different technologies as non-wires alternatives.

7.1.1 SAWYER PASSWAY SOLAR

The Company installed 1.3MW Photovoltaic (PV) facility that was placed in service in 2017. This project was implemented in conjunction with the Department and the DOER to further the renewable energy goals of the Commonwealth of Massachusetts. This project is installed on a brownfield site of an old coal gasification plant allowing the company to make use of location that is not suitable for most uses. Since the project was installed and as of the end of 2019 the system has generated approximately 4,430MWh which has offset electricity that would have otherwise been purchased through the ISO-NE market. The Company continues to evaluate this type of installation as a non-wires alternative to traditional utility investment.

7.1.2 TOWNSEND SUBSTATION BATTERY STORAGE

The Company is in the process of installing a 2MW/4MWh energy storage facility that is scheduled to be placed in service in 2021. The Company submitted and was awarded a grant covering one-half of the project cost by the MA Clean Energy Council. The energy storage facility is being installed to defer the need to upgrade substation transformer capacity. The addition of the grant allowed this project to be a good non-wires alternative to the traditional substation upgrade project. This project is being implemented outside of the Grid Modernization Plan and the Company is not seeking recovery of this project through the GMF. This is the first battery storage project the Company is installing. The Company will evaluate this project as a non-wires alternative to traditional utility investment.

7.1.3 NON-WIRES ALTERNATIVE RFP

The Company continues to investigate other non-wire alternatives. In early 2019 as part of the UES-Capital (New Hampshire) system planning process the Company identified the possible overload of the 37 line from Penacook to MacCoy Street tap in 2020 following the switching to restore all load for the contingent loss of the circuit 4X1 supply.

The proposed traditional option to resolve this constraint is to reconductor the 37 line from Penacook to the MacCoy Street tap in 2020. The estimated cost to reconductor the 37 line is $750,000 without overheads. The Company obtained information regarding NWA projects to defer this project. The project RFP was released to 19 potential bidders and received four (4) bids all focused on PV or PV coupled with solar options. The result of the bid process was all of the bids were between 10-15 times more expensive even after taking into consideration all of the other benefits (i.e. energy produced, capacity offset, solar credits, etc.). The Company decided to implement the traditional solution.

The Company has rewritten its planning criteria to require projects that meet a certain criteria must be evaluated for non-wires alternatives.

7.2 ADVANCING THE GRID

Electricity is the lifeblood of modern civilization. It powers homes, businesses, industrial production and even cars. It powers the basic necessities of heat, light, refrigeration and cooking, as well as computers, networks, communication services and entertainment. It keeps us connected. It is essential to our growth, prosperity, standard of living and sense of well-being. Without it, modern society grinds to a halt. Everything runs on electricity. And yet, every kWh of electricity we consume contributes almost a pound of carbon dioxide to the atmosphere.

The global need to reduce carbon emissions has driven an unprecedented transformation of the energy sector. Enormous investments in clean energy and efficient end-use technologies have led to sharp declines in greenhouse gas emissions. Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets and home energy technologies previously unimagined. Advancements in technology are driving down the cost of clean energy, making it more affordable for consumers. Energy markets continue to develop as innovators develop new tools to control and manage energy usage and market new energy services directly to end-use customers.

As customers adopt new technologies, and as distributed energy resources are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system (the “grid”) must change. The 20th Century electric grid, originally designed to distribute power from large centralized generating plants, must now integrate a wide array of distributed load, storage and generation resources. A grid that was designed for “one way” power flow must now accommodate two-way power flow, increasing the need for sophisticated protection, communication, metering, and intelligence. The grid must also provide opportunities for customers to understand and actively participate in energy markets to enhance efficient utilization and consumption of electricity, while delivering improved reliability and power quality.

Utility operations are transitioning away from the traditional model of energy delivery, to one that integrates and optimizes the needs and interests of consumers, producers, markets, service providers and other participants. New markets and new technologies are rapidly emerging in response to changing policies, climate action, and the changing preferences of customers. We are seeing a significant transformation in how customers are powering their homes and businesses, including the ability to generate and store their own electricity. More recently, the promise of affordable electric vehicles has moved from niche to mainstream. Implementing enabling technologies and programs to facilitate these activities will make the electric system more efficient, economic and environmentally friendly.

For over a decade, Unitil has visualized the utility of the future as an enabling platform with the capabilities to unlock the full potential of today’s customers, markets and technologies. Our Vision is to transform the way people meet their evolving energy needs to create a clean and sustainable future. We are at a tipping point where the time to achieve this vision is now.

7.2.1 Enabling Platform for the 21st Century

A reliable, affordable and fully modernized electric grid is an essential pillar of modern society. It will power the basic necessities of life while supporting new technologies, services and interactivity. It will operate more efficiently, optimize grid-connected resources and enable dramatic expansion of clean energy to protect and preserve the environment. It will foster innovation and enable new markets by optimizing benefits to customers, service providers and other stakeholders. At its fullest potential, it will harness technology innovation to connect customers, markets, solution providers and new technologies to achieve the full potential of an advanced 21st Century energy system.

Over the years this vision has been variously referred to as Grid Modernization, or the Modern Grid, and even the Smart Grid. But what is a Modernized Grid exactly? What does a Smart Grid look like? Is it the poles, wires and electrical infrastructure of the utility? Is it an intelligent, highly digitized electricity network that forms the basis for a “smart” power delivery system? Does it refer to the utility system, or the broader integration of customers, markets, solution providers, and others? If you ask ten different people, you will get ten different answers.

To achieve the promise of a fully modernized grid, Unitil views the electric grid and the devices connected to it as a communicating, intelligent grid-connected ecosystem of people, devices, information and services. The grid is only a part of this larger energy ecosystem, but it is the foundation upon which everything is built. The role of utility in this context is to enable seamless grid access, link participants, optimize resources and foster technology innovation. The modern grid isn’t just an electrical network, it’s a community of grid-connected and grid-enabled customers and third parties.

To provide a simple analogy, one could ask – what is the internet? In strictly technical terms the internet is a global system of interconnected computer networks that use a standard Internet protocol suite (TCP/IP) to link billions of devices worldwide. But ask any non-technical person what the internet is, and they will describe a vast world of services and information where they can access online shopping, banking, news, social media and entertainment services. It’s where people go to trade stocks, make dinner reservations, download books, and connect with other people. The internet is the primary source of information, entertainment content and interactive services for most people in the 21st Century.

From a user perspective, the internet isn’t communication infrastructure and it isn’t the network of their Internet Service Provider. Instead, the internet is defined by its content, services, connectivity and interactivity. It connects billions of people and devices to an unlimited universe of services and information, and is a platform for endless innovation. The Internet of Things has quickly transitioned to the Internet of Everything.

The modern grid can be thought of in similar terms. The utility grid is clearly the foundation upon which a more advanced energy ecosystem will be built. But from a user perspective, the critical ingredient to achieve the promise of a “Smart Grid” is not electricity, but information. The grid of the future will provide seamless two-way flows of both energy and information. It will be defined not by the electricity it carries, but by the information, functionality and interactive services it provides. In fact, this vision is a part of what has become known as Internet of Energy (IoE).

7.2.2 Merging Power and Information

The advanced grid will be much more than a "poles and wires" delivery system for electricity. It will enable electrical, informational and financial transactions among customers, grid operators, service providers, markets, and other stakeholders. In doing so, it will improve load factor, lower system losses, optimize asset utilization and avoid investments driven by "peaky" load and poor utilization. Planners and engineers will have the information to build what is needed, when it is needed, while more effectively managing capacity and resources on a day-to-day basis. Reliability will be improved through advanced outage management, distribution management and automation systems, geographical information systems and other technologies.

Achieving this vision requires a paradigm shift in what has traditionally been viewed as grid infrastructure, as well as the types of investments needed to achieve advanced functionality. Traditional utility investments focused primarily on upgrading and maintaining "electrical" infrastructure to ensure safety and reliability, increase capacity, and expand service to new customers. Customers were viewed as consumers of electricity, and the grid was designed to distribute power from large centralized generating plants to end-use consumers. Assets and investments have traditionally consisted of poles, wires, substations, and electrical equipment.

To achieve the promise of the Eco-Grid, investments in Information Technology (IT) and Operational Technology (OT) are needed to create an open, flexible platform integrating customers, competitive markets and service providers. Collectively known as "intelligence" infrastructure, these investments will include communication networks, sensors and control devices, and advanced information and management systems. Under this vision the Eco-Grid is not simply a newer, upgraded version of the legacy electric system, nor is it a specific technology or suite of technologies layered onto the existing utility systems. The Eco-Grid is instead the foundation of a larger ecosystem of customers, competitive markets and service providers who are interacting with the utility electric grid and the utility's information systems. Information and the exchange of information will be the lifeblood of this grid-connected ecosystem.

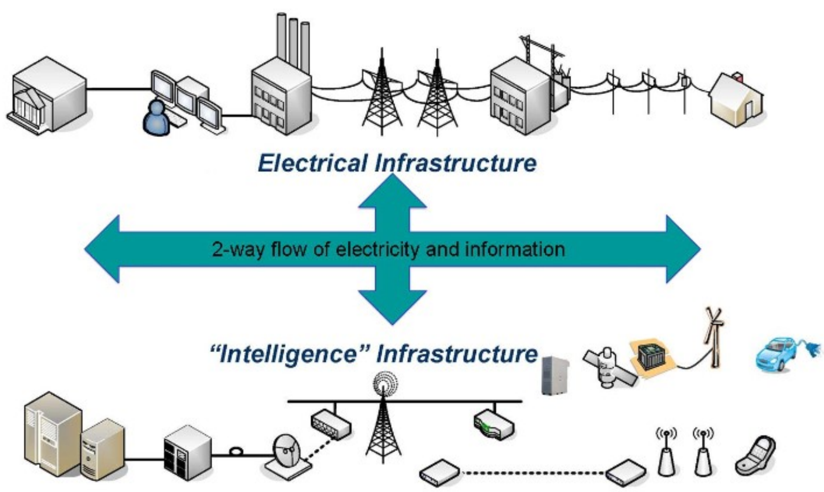

Figure 3: Electrical vs. Intelligence Infrastructure

7.2.3 Enabling Markets

As customers increasingly adopt new technologies including behind-the-meter generation, storage and energy management systems, the relationship between the utility and the consumer is changing. Customers are increasingly empowered to manage their energy use by taking full advantage of the information, market mechanisms, energy efficient technologies, diverse fuel sources, and transportation options available to them. In turn, our understanding of a utility “customer” must expand to encompass consumers, generators, prosumers (customers who consume electricity from and produce electricity onto the electric system), and other grid participants receiving or providing ancillary services. The Eco-Grid will support the creation of new electricity markets from home energy management systems in customers’ homes, to technologies that allow consumers and third parties to bid their energy resources into wholesale markets.

Innovation will be the driving force behind new electricity markets and services, and will develop from information collected and maintained by the utility and shared externally with customers and service providers. The availability of this information will be crucial to the development of a more efficient and environmentally friendly grid. The Eco-Grid will provide a platform for customers to understand and actively participate in energy markets in order to enhance efficient utilization and consumption of electricity, while also supporting diverse activities by third parties. Grid operators will treat willing consumers as resources in the day-to-day operation of the grid. Well-informed consumers will modify consumption based on the balancing of their demands and resources with the electric system’s capability to meet those demands.

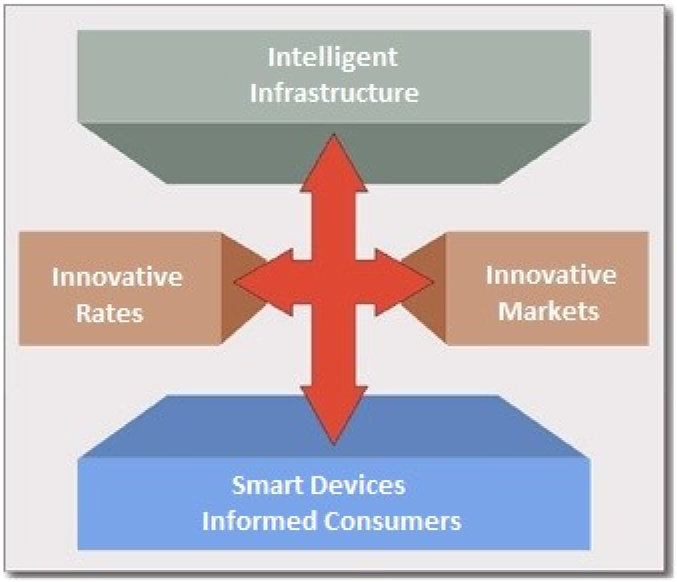

Figure 4: Enabling Markets

The grid of the future will be the foundation for a holistic energy ecosystem consisting of customers, competitive markets, third party providers and new technologies working together to achieve the promise of a clean energy future. Our vision is to create an ecosystem of innovation.

7.2.4 FOUNDATIONAL OBJECTIVES

What will an advanced grid do differently than the legacy electric system of the past century?

- Deliver safe and reliable service meeting the expectations of today's customers, and the needs of a 21st Century economy.
- Engage customers and encourage their active participation in energy markets by enabling the easy adoption of new technologies and services so they can better manage their energy needs.
- Reduce the environmental impact of electricity generation by seamless integrating all types of generation and storage options, and by improving efficiency and optimizing demand.
- Support the interconnection and business models of third parties and encourage innovation.

Unitil has identified a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives are crafted with guidance from the United States Department of Energy, New Hampshire Public Utilities Commission and Massachusetts Department of Public Utilities and are used to identify the investments and technologies that best serve this new era.

Examining these agencies and their goals revealed an emerging consensus around eight key areas of interest:

Objective 1: Environmentally Friendly – We must firmly support the region's goals in reducing emissions in the battle against climate change.

Unitil unilaterally supports our region's stated goals to reduce emissions in supports of the battle against climate change. We believe utilities must enable the integration of renewable energy projects that will deliver emission-free solar, wind and hydro power to our region. We must also support energy efficiency and time-of-use initiatives which allow customers to take control of their own usage, further lowering emissions. We must educate and empower customers to shift their energy usage away from peak times of need, an action that not only provides substantial environmental benefits, but reduces overall demand and allows the system as a whole to operate more efficiently.

Objective 2: Safety and Reliability – We must continuously improve safety, reliability and resilience while reducing the effects of outages.

Providing safe and reliable service at an affordable cost to all customers is central to Unitil's Company Mission. The grid must be operated in a manner that ensures public and employee safety. Electricity must be delivered at a safe, stable, consistent voltage optimized for use by homes and businesses, and outages must be kept to a minimum. When storms do occur, the system must be built in a way that restoration can occur rapidly and efficiently.

Objective 3: Customer Service – We must improve and embrace customer empowerment, engagement, and education. We must give the customer the tools they need to understand and control both their own energy usage and energy matters in the region.

As more and more at-home innovations evolve the way we use electricity, there is a growing customer need for a trusted energy advisor. Access to personal data on energy usage will help to empower customers to actively manage and understand their own technology and usage decisions, resulting in lower bills. Electric vehicles, heat pumps, smart appliances and energy management systems are changing the manner in which customers utilize energy and interact with the system. Home energy management systems require real-time information to help customers make decisions on how to optimize energy usage at home. Electric vehicle rate structures will help customers program when charging occurs and plan accordingly.

Objective 4: Security – We must ensure the cyber and physical security of the grid remains strong.

Strong cyber and physical security are cornerstones in ensuring the safety and reliability central to our Mission. The modern grid must reduce physical and cyber vulnerabilities while also enabling rapid recovery from disruptions. The secure sharing and rapid analyzation of accurate information will be central to a modernized energy ecosystem and the development of new energy markets and services. Data security and customer privacy must be carefully integrated into existing operational practices.

Objective 5: Flexibility – We must ensure the grid remains flexible enough to accommodate and integrate all types of new energy sources.

Small scale and large scale renewable energy projects are making the flow of electricity in cities and neighborhoods more complex. Managing this flow will require a smart, flexible system that not only makes interconnections easier for end-users, but allow system operators to rapidly switch over to utility-scale, reliability focused energy suppliers when required.

Objective 6: Affordability – Energy for life must remain affordable for all.

Ensuring fair prices is central to any modern grid design model. By ensuring our system infrastructure is a flexible, enabling platform, we are able to integrate customers with competitive markets and other service providers in a ways deliver affordable energy choices for all. Such a system gives customers the opportunity to make decisions on how they use the grid, when they use the grid, and how best to maximize value.

Objective 7: Demand and Asset Optimization – The grid must be designed to get the most out of the tools and resources interconnected in order to best serve the region.

When renewable energy systems are connected to the system, we want to ensure interconnections are optimized for both the generator and end-users. The modern grid has advanced tools and technology in place to optimize system performance and improve the grid's performance from reliability, environmental, efficiency and economic perspectives. System demand is reduced through greater efficiency to control total system costs for generation, transmission and distribution. Advanced system planning tools will integrate the benefits of distributed energy resources and identify locations where these assets can be optimized. The objective here is to not necessarily operate all equipment to their ratings or limits. Rather, assets will be managed to only deliver what is required at the time. Real-time data will provide the information required to reduce operating and maintenance costs along with the environmental benefits associated with improved efficiency and fewer failures.

Objective 8: Technology Innovation – The grid must enable the easy adoption of new technologies as they are developed to further support customer choice and system operations.

Effective technology and secure data sharing is crucial to operating a transparent and open energy system. Customers and other users want to make informed decisions on their energy needs, and data from the Energy Hub makes sharing simple and intuitive. Developers, meanwhile, need clear rules for how to interconnect renewable energy projects as well as an understanding of where interconnections would maximize the value to the system.

There are inherent complexities and challenges associated with supporting each objective individually without considering the whole. Offering customers more technologies and increased data sharing can potentially increase risk of cyberattacks, which in turn creates security challenges. The early adoption of some emerging technologies can come at a premium, and associated costs creates conflicts with the goal of keeping energy affordable. The intermittent nature of some forms of renewable energy sources can be at odds with the reliable service our customers expect. The list goes on.

It is in recognizing the push and pull these objectives have on one another where the maximum benefit to all customers can be found. The system must be operated in a manner which optimizes the benefits for all while ensuring all voices and viewpoints are heard and represented. Balancing all objectives is the key to unlocking this utility future state we aspire towards.

7.2.5 SMART TRANSPORATION AND HEATING SOLUTIONS VISION TEAM

Another vision focus team created by the company is the Smart Transportation and Heating Solutions team. The Company is committed to a sustainable, low-carbon and affordable energy future for our customers, our people and the communities we serve. The Smart Transportation & Heating Solutions Vision Team was established to explore, evaluate, recommend, and facilitate the implementation of mid to long-term strategies and initiatives focused on the transformation of the transportation and thermal sectors to low-carbon alternatives. Our focus is a transition to electrification and other low-carbon fuels for the transportation sector and helping our customers' transition to next-generation electric and/or gas systems within the heating sector.

8 CONCLUSION

Overall, the Company is making significant progress towards the design and implementation of its Grid Modernization plan. The templates developed as a means to measure progress associated with the plan focus primarily on number of units installed and the amount of money spent on the implementation. The Company's efforts over the past year have transitioned from evaluation and design to specification and implementation. Our approach has already proven beneficial to our grid modernization efforts. The Company's analysis and design work has identified efficiencies such as combining VVO functionality with the ADMS and adjusting the schedule to align the FAN, VVO, ADMS and SCADA projects. A considerable amount of effort has been expended even though these efforts are not easily quantified with number of units installed or amount of money spent.

The Company experienced challenges with respect to COVID-19 which affected material lead times and project implementation schedules. The Company continued to advance the implementation of our grid modernization plan, but not at the pace we had planned for. The COVID-19 pandemic had a quick and dramatic impact on the Company, our workforce and customers. Safe and reliable service continues to be the top priority of the Company. It is unclear at this point what the ultimate impact the pandemic will ultimately have on the Company's workforce, vendors and supply chain.

The Company continues 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.

Appendix 1

DPU Appendix 1 Template

NOTE:

DPU APPENDIX 1 TEMPLATE PROVIDED IN ELECTRONIC FORMAT ONLY

Appendix 2

System Automation Saturation

2020 EOY			Partially Automated Devices						Fully Automated Devices					
Substation	**Circuit**	**Customers**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Capacitors & Regulators** [Note 3]	**Partially Automated Device Sub-Totals**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Fully Automated Device Sub-Totals**	**System Automation Saturation**
Beech Street	1W1	448	0	0	0	0	0	0	1	0	0	0	1	448.0
Beech Street	1W2	2,007	0	1	0	0	0	1	1	0	0	0	1	1,338.0
Beech Street	1W4	1,629	0	1	0	0	0	1	1	0	0	0	1	1,086.0
Beech Street	1W6	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Beech Street		**4,085**	**0**	**2**	**0**	**0**	**0**	**2**	**4**	**0**	**0**	**0**	**4**	817.0
Canton Street	11H10	748	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11H11	373	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11W11	1,748	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street		**2,869**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	---
Townsend	15W14	0	0	0	0	0	0	0	1	1	0	0	2	0.0
Townsend	15W15	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Townsend	15W16	1,514	0	0	0	0	0	0	1	0	0	0	1	1,514.0
Townsend	15W17	573	0	0	0	0	0	0	1	0	0	0	1	573.0
Townsend		**2,088**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**1**	**0**	**0**	**5**	417.6
Nockege	20W22	901	1	0	0	0	0	1	0	0	0	0	0	1,802.0
Nockege		**901**	**1**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	1,802.0
Wallace Road	1341	1	0	0	0	0	0	0	2	0	0	0	2	0.5
Wallace Road		**1**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**0**	**0**	**0**	**2**	0.5
Sawyer Passway	22W1	2,081	0	0	0	0	0	0	1	0	0	0	1	2,081.0
Sawyer Passway	22W2	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W3	20	0	0	0	0	0	0	1	0	0	0	1	20.0
Sawyer Passway	22W8	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W10	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W11	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W12	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Sawyer Passway	22W17	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Sawyer Passway	Network	485	0	0	0	0	0	0	0	0	0	0	0	---
Sawyer Passway		**2,587**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**0**	**0**	**0**	**8**	323.4
River Street	25W27	1,227	1	0	0	0	0	1	0	0	0	0	0	2,454.0
River Street	25W28	623	1	0	0	0	0	1	0	0	0	0	0	1,246.0
River Street	25W29	1	0	0	0	0	0	0	1	0	0	0	1	1.0
River Street		**1,851**	**2**	**0**	**0**	**0**	**0**	**2**	**1**	**0**	**0**	**0**	**1**	925.5
Lunenburg	30W30	1,347	0	0	0	0	0	0	1	0	0	0	1	1,347.0
Lunenburg	30W31	1,658	0	2	0	0	0	2	1	2.5	0	0	3.5	368.4
Lunenburg		**3,005**	**0**	**2**	**0**	**0**	**0**	**2**	**2**	**2.5**	**0**	**0**	**4.5**	546.4
Pleasant Street	31W34	1,251	0	0	0	0	0	0	1	0	0	0	1	1,251.0
Pleasant Street	31W37	1,238	0	0.5	0	0	0	0.5	1	7.5	0	0	8.5	141.5
Pleasant Street	31W38	1,319	0	0	0	0	0	0	1	1	0	0	2	659.5
Pleasant Street		**3,808**	**0**	**0.5**	**0**	**0**	**0**	**0.5**	**3**	**8.5**	**0**	**0**	**11.5**	324.1
Rindge Road	35W36	779	0	0	0	0	0	0	1	3	0	0	4	194.8
Rindge Road		**779**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**	**0**	**0**	**4**	194.8
West Townsend	39W18	1,966	0	0	0	0	0	0	1	4	0	0	5	393.2
West Townsend	39W19	1,316	0	1	0	0	0	1	1	1	0	0	2	526.4
West Townsend		**3,282**	**0**	**1**	**0**	**0**	**0**	**1**	**2**	**5**	**0**	**0**	**7**	437.6

2020 EOY			Partially Automated Devices						Fully Automated Devices					
Substation	**Circuit**	**Customers**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Capacitors & Regulators** [Note 3]	**Partially Automated Device Sub-Totals**	**Feeder Breakers** [Note 1]	**Distribution Reclosers, etc.** [Note 2]	**Padmount Switchgear**	**Network Transformers/ Protectors**	**Fully Automated Device Sub-Totals**	**System Automation Saturation**
Summer Street	40W38	4	0	0	0	0	0	0	1	0	0	0	1	4.0
Summer Street	40W39	428	0	0	0	0	0	0	1	1	0	0	2	214.0
Summer Street	40W40	1,579	0	2.5	0	0	0	2.5	1	0	0	0	1	701.8
Summer Street	40W42	1,725	0	0	0	0	0	0	1	1	0	0	2	862.5
Summer Street	1303	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Summer Street	1309	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Summer Street		**3,736**	**0**	**2.5**	**0**	**0**	**0**	**2.5**	**6**	**2**	**0**	**0**	**8**	403.9
Princeton Road	50W51	657	0	0	0	0	0	0	1	0	0	0	1	657.0
Princeton Road	50W53	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Princeton Road	50W54	0	0	0	0	0	0	0	1	0	0	0	1	0.0
Princeton Road	50W55	191	0	0	0	0	0	0	1	0	0	0	1	191.0
Princeton Road	50W56	149	0	0	0	0	0	0	1	0	0	0	1	149.0
Princeton Road		**998**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**0**	**0**	**0**	**5**	199.6
	Total Customers	**29,990**					**Total Partially Automated Devices**	**11**				**Total Fully Automated Devices**	**60**	**457.9**

Note 1: Includes both breakers and reclosers that are used as substation circuit terminals. Does not include other substation breakers or reclosers.

Note 2: Includes distribution reclosers, sectionalizers, automated line switches, S&C IntelliRupters and Siemens Fusesavers.
Does not include capacitor bank switches.
Banks of multiple single-phase devices are counted as one.

Note 3: Does not include substation capacitor banks, transformer LTCs or bus regulators.

Appendix 3

Number/Percentage of Circuits with Installed Sensors

2020 EOY

		Number of Sensors By Type										
Substation	Circuit	Feeder Breakers [Note 1]	Distribution Reclosers, etc. [Note 2]	Padmount Switchgear	Network Transformers/ Protectors w/ full SCADA	Network Transformers/ Protectors w/ monitoring, no control	Feeder Meters [Note 3]	Capacitors & Regulators [Note 4]	Line Sensors	Fault Indicators	other Voltage Sensing	Sensor Sub-Totals
Beech Street	1W1	1	0	0	0	0	0	0	0	0	1	2
Beech Street	1W2	1	1	0	0	0	0	0	0	0	0	2
Beech Street	1W4	1	1	0	0	0	0	0	0	0	0	2
Beech Street	1W6	1	0	0	0	0	0	0	0	0	0	1
Beech Street		**4**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**7**
Canton Street	11H10	0	0	0	0	0	0	0	0	0	1	1
Canton Street	11H11	0	0	0	0	0	0	0	0	0	1	1
Canton Street	11W11	0	0	0	0	0	0	0	0	0	0	0
Canton Street		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**2**
Townsend	15W14	1	1	0	0	0	0	0	0	0	0	2
Townsend	15W15	1	0	0	0	0	0	0	0	0	0	1
Townsend	15W16	1	0	0	0	0	0	0	0	0	4	5
Townsend	15W17	1	0	0	0	0	0	0	0	0	2	3
Townsend		**4**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**6**	**11**
Nockege	20W22	0	0	0	0	0	0	0	0	0	5	5
Nockege		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**5**
Wallace Road	1341	2	0	0	0	0	0	0	0	0	0	2
Wallace Road		**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**
Sawyer Passway	22W1	1	0	0	0	0	0	0	0	0	4	5
Sawyer Passway	22W2	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W3	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W8	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W10	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W11	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W12	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	22W17	1	0	0	0	0	0	0	0	0	0	1
Sawyer Passway	Network	0	0	0	0	0	0	0	0	0	0	0
Sawyer Passway		**8**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**12**
River Street	25W27	1	0	0	0	0	0	0	0	0	4	5
River Street	25W28	1	0	0	0	0	0	0	0	0	1	2
River Street	25W29	1	0	0	0	0	0	0	0	0	0	1
River Street		**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**8**
Lunenburg	30W30	1	0	0	0	0	0	0	0	0	3	4
Lunenburg	30W31	1	2.5	0	0	0	0	0	0	0	1	4.5
Lunenburg		**2**	**2.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**8.5**

2020 EOY

Substation	Circuit	Number of Sensors By Type: Feeder Breakers [Note 1]	Distribution Reclosers, etc. [Note 2]	Padmount Switchgear	Network Transformers/ Protectors w/ full SCADA	Network Transformers/ Protectors w/ monitoring, no control	Feeder Meters [Note 3]	Capacitors & Regulators [Note 4]	Line Sensors	Fault Indicators	other Voltage Sensing	Sensor Sub-Totals
Pleasant Street	31W34	1	0	0	0	0	0	0	0	0	3	4
Pleasant Street	31W37	1	7.5	0	0	0	0	0	0	0	0	8.5
Pleasant Street	31W38	1	1	0	0	0	0	0	0	0	0	2
Pleasant Street		**3**	**8.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**14.5**
Rindge Road	35W36	1	3	0	0	0	0	0	0	0	1	5
Rindge Road		**1**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**5**
West Townsend	39W18	1	4	0	0	0	0	0	0	0	2	7
West Townsend	39W19	1	1	0	0	0	0	0	0	0	2	4
West Townsend		**2**	**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**11**
Summer Street	40W38	1	0	0	0	0	0	0	0	0	0	1
Summer Street	40W39	1	1	0	0	0	0	0	0	0	3	5
Summer Street	40W40	1	1	0	0	0	0	0	0	0	4	6
Summer Street	40W42	1	1	0	0	0	0	0	0	0	0	2
Summer Street	1303	1	0	0	0	0	0	0	0	0	0	1
Summer Street	1309	1	0	0	0	0	0	0	0	0	0	1
Summer Street		**6**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**7**	**16**
Princeton Road	50W51	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W53	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W54	1	0	0	0	0	0	0	0	0	0	1
Princeton Road	50W55	1	0	0	0	0	0	0	0	0	1	2
Princeton Road	50W56	1	0	0	0	0	0	0	0	0	0	1
Princeton Road		**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**6**

Total number of Substations/Transformers	**13**
Total number of Substations/Transformers with Sensors	**13**
% of Substation/Transformers with Sensors	**100.0%**
Total number of Circuits	**45**
Total number of Circuits with Sensors	**40**
% of Substation/Transformers with Sensors	**88.9%**

Note 1: Includes both breakers and reclosers that are used as substation circuit terminals. Does not include other substation breakers or reclosers.

Note 2: Includes distribution reclosers, sectionalizers, automated line switches, S&C IntelliRupters and Siemens Fusesavers.
Does not include capacitor bank switches.
Banks of multiple single-phase devices are counted as one.

Note 3: Includes metering or other IEDs applied at substation circuit terminals. Does not include other substation meters or IEDs.

Note 4: Does not include substation capacitor banks, transformer LTCs or bus regulators.