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

2018-2021
Grid Modernization Plan
Term Report

Massachusetts Department of Public Utilities
D.P.U. 22-42

Dated: 4-1-2022

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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 OVERVIEW

On May 10, 2018, the Department of Public Utilities ("Department") approved the first grid modernization plans for NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric"), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid"), and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil" or "FG&E") (together, "the Companies"; individually, "Company"). Grid Modernization Plan, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122 (2018). On May 12, 2020, the Department extended the first grid modernization plan term through calendar year 2021. D.P.U. 15-120-D/D.P.U. 15-121-D/D.P.U. 15-122-D at 1, 6-7 (2020).

Consistent with the Orders and each Company's Department-approved grid modernization factor ("GMF") tariff, each company must submit annually: (1) a Grid Modernization Annual Report by April 1 that documents the company's performance under its plan during the prior calendar year; and (2) a grid modernization cost recovery filing with proposed GMFs. NSTAR Electric, M.D.P.U. No. 73E at 7; National Grid, M.D.P.U. No. 1469, at 5-6; Unitil, M.D.P.U. No. 376, at 6-7; D.P.U. 15-120/ D.P.U. 15-121/D.P.U. 15-122, at 112, 114, 225-226, 234.

Additionally, by April 1, 2022, each Company must submit a Grid Modernization Term Report that documents the company's performance during the entirety of the term. NSTAR Electric, M.D.P.U. No. 73E at 8; National Grid, M.D.P.U. No. 1469, at 6; Unitil, M.D.P.U. No. 376, at 7; D.P.U. 15-120-D/D.P.U. 15-121-D/D.P.U. 15-122-D at 4 n.3; D.P.U. 15-120/ D.P.U. 15-121/D.P.U. 15-122, at 112, 115.

On October 25, 2021 the Department opened Docket D.P.U. 21-116 to establish a standard reporting format for each Company's 2018-2021 Grid Modernization Term Report. The Department proposed a narrative outline and a data reporting template for the Grid Modernization Term Reports and sought comment. On November 18, 2021, the companies filed joint comments and no other comments were submitted.

On February 15, 2022, the Department issued a Hearing Officer Memorandum to: (1) assign docket numbers for each Company's 2018-2021 Grid Modernization Term Report; (2) establish the form and content of the Grid Modernization Term Report, (3) consolidate the Department's final review of each Company's annual GMF filings with the Department's review of the term reports; (4) incorporate certain documents into each company's Grid Modernization Term Report proceeding; and (5) require each Company to submit a preliminary exhibit list with its Grid Modernization Term Report Filing.

Unitil submits this 2018-2021 Grid Modernization Term Report in compliance with the Orders and directives in this case.

1.1 TERM PROGRESS TOWARD GRID MODERNIZATION OBJECTIVES

The Company's approach to its GMP as initially filed consisted of a higher level analysis which identified and estimated project costs 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.

When the Order was issued in 2018, the Company completed a review of the proposed projects to make certain that the projects were still appropriate from a scope, schedule, and estimate basis. This review 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 2018-2021 Grid Modernization Term Report covers activities from 2018-2021 and describes the Company's progress towards implementing its GMP. 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 GMP. The templates developed as a means to measure progress associated with the plan focus primarily on the number of units installed and the amount of money spent on the implementation. The Company's efforts from 2018-2021 are better described as analysis, evaluation, specification, RFP, evaluation, initial purchase, scope of work development and some project implementation. 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. Considerable effort has been expended even though these efforts are not easily quantified by number of units installed or amount of money spent.

In 2021, the Company continued with a successful implementation of its ADMS system, FAN and 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. However, this approach relies on the same group of resources to implement each of the projects. Therefore, the Company has been forced to adjust its schedule on some projects.

The Company also experienced some challenges associated with the COVID -19 pandemic during the term. 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 lead-time standpoint. It is difficult to quantify the total effect the pandemic had and will continue to have on 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 TERM GRID MODERNIZATION DEPLOYMENT (ACTUAL V. PLANNED)

The Company has been working on the more detailed design and analysis required to implement the investments identified in its GMP since the Order was issued in 2018. 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 continued to make significant progress in the design and implementation of the FAN and mobile damage assessment projects in 2021.

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 to expand the coverage and functionality of Company's SCADA system at substations. The second project is to further integrate OMS with the Company's Advanced Metering Infrastructure (AMI) system.

At the start of the GMP, SCADA was already implemented to some extent at some FG&E substations, and not at all at others. Furthermore, at many substations that had some level of existing SCADA capability, it was not complete to the extent intended under the GMP. Therefore, the SCADA project in the GMP adds SCADA at those substations that do not presently have it, and expands SCADA capabilities at other substations where it is presently incomplete.

This SCADA project set out to perform additions or expansions at five (5) substations over the course of years 2018 through 2021. The Company has completed these SCADA implementations for the first four (4) of those substations (Rindge Road, Townsend, Beech Street and Lunenburg), and the implementation at the fifth substation (Princeton Road) was in progress at the end of 2021. While the SCADA expansion at this fifth substation was initially slated to be completed in 2021, the remaining work there was deferred into the following year to allow the Company to redirect SCADA engineering resources to support the ADMS and VVO projects.

The Company has completed a functionally complete prototype of the further integration of OMS with AMI; including the development of a homogeneous outage data lake with data from our AMI and OMS systems and cellular communication history, and we continue to test and tune approaches to a "scoring algorithm". Implementation of the Company's new ADMS/OMS systems, which resulted in a significantly more locked down and secure networking environment, as well as the ongoing configuration and installation work for those systems as we begin production roll outs, has presented challenges in integrating with the data necessary from these platforms for the AMI/OMS integration to be completed. As a result, work on this project has been on hold while we work through these challenges. The Company expects that work will begin again in 2022, but a new and finalized schedule for this is pending at this time. The Company 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 outage confidence scores.

Volt/VAr Optimization ("VVO") investment Category

The VVO 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 retrofitted. Voltage and energy monitors (sensors) are also installed as required at strategic locations on the circuits. The Company 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, which will be deployed on a substation by substation basis. The goal is for each substation to have all of the projects and functionality completed at the same time as opposed to multiple discreet efforts. In some cases, the SCADA project will be complete prior to the other efforts, since SCADA functionality is prerequisite to the VVO and ADMS commissioning.

The construction of all VVO equipment began for the circuits served from Townsend, Summer Street, and Lunenburg substations in 2020 and West Townsend in 2021. All equipment served from Townsend substation was installed and commissioned in 2021. The VVO functionality for the Townsend circuits will be tested via the ADMS throughout 2022. The installation and commissioning for the other substations are planned for future years per the table in Section 3.1.2.1.5.

Advanced Distribution Management System ("ADMS") 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 2021, the Company continued implementation of ADMS. The ADMS production environment as well as the new secure IT network in which the ADMS platform operates went live. The ADMS SCADA master was also commissioned in the production environment including Townsend substation, its associated distribution VVO equipment, and a majority of the large DER facilities connected to the Company's electric system. Additionally, the Company made significant progress in the implementation of unbalanced loadflow and VVO of Townsend substation and the three circuits it serves. The Company successfully implemented unbalanced load flow in the production environment for Townsend substation just prior to the cutoff for this report in early 2022.

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 a foundational technology.

In 2020, the Company selected a vendor for 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.

The Company awarded the FAN contract to AT&T and will utilize the 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 has finalized the cell modems that will be used in the FAN.

In 2021, the Company completed the installation and testing two fiber optic backhaul circuits (primary and backup). The Company identified the communications equipment required at each of the field devices, developed a design for each type of installation, and designed the settings. The communications equipment was installed in 22 controllers in the shop and bench tested prior to being installed in the field. This bench testing process helps avoid deploying any faulty equipment which would result in multiple truck rolls. The Company now has the design, installation and testing procedures completed and has begun the process of installing communication devices on the Summer Street substation circuits.

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.

A project team was 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 better understand their proposal and have 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, the Company determined 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.

Beginning in January 2021, members of the project team began working with the SSP team to implement the MIMS solution with the design and development phases being completed throughout Q2 and Q3 of 2021. Initially the MIMS software was scheduled to be installed and tested throughout Q3 and Q4, however that work was postponed to Q1 of 2022 due to development issues and resource constraints. Upon installation, testing and validation will begin with complete deployment of the solution by the end of 2022.

1.3 SUMMARY OF TERM SPENDING (ACTUAL V. PLANNED)

The Department issued a memorandum on March 11, 2021 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 is to 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 is to explain the discrepancy.

In addition the Department's March 11, 2021 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.

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 5d of the Company's D.P.U. Appendix 1 for 2018-2021. Overall the Company's spending continues to be lower than projected due to the timing of project implementation.

1.3.1 CAPITAL SPENDING (ACTUAL V. PLANNED SPENDING)

The Company has been working on more detailed design and analysis to confidently implement the GMP capital investments identified in its GMP. Table 1 below demonstrates the actual spending versus the plan.

	Actual Capital Spending				2018-2021 Actual	2018-2021 Planned (Note 2)
	2018	2019	2020	2021		
Monitoring and Control						
SCADA	$ -	$ 215,012	$ 608,203	$ 76,050	$ 899,265	$ 1,062,561
OMS Integration with AMI *(Note 1)*	$ -	$ 22,800	$ 57,136	$ 10,785	$ 90,721	$ 129,936
Volt VAr Optimization						
VVO	$ -	$ 10,369	$ 1,787,195	$ 730,299	$ 2,527,863	$ 5,115,762
Advanced Distribution Management System						
ADMS	$ -	$ -	$ 172,724	$ 161,853	$ 334,577	$ 597,724
DERMS	$ -	$ -	$ -	$ -		$ -
Field Area Network						
Field Area Network	$ -	$ 107,057	$ 324,556	$ 397,046	$ 828,659	$1,161,461
Workforce Management						
Mobile Platform Damage Assessment *(Note 1)*	$ -	$ -	$ -	$ 272,192	$ 272,192	$ 650,000
Total						
Total	$ -	$ 355,238	$ 2,949,814	$1,648,225	$ 4,953,277	$7,717,444

Table 1 – Planned Versus Actual Capital Spending

Note 1: This is a software project the Company has decided to deploy 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%. Although, ADMS is a software project, the costs shown are only the costs associated with FG&E.

Note 2: The 2018-2021 planned amount is derived from Tab 5c 2020 Spending of Appendix 1 of the Company's 2020 Annual Grid Mod Report.

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 endeavors to make up for these delays in future years.

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, 2020 and 2021 as shown 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 Incremental O&M Spending				Total Spending
	2018	2019	2020	2021	
Monitoring and Control					
SCADA	$ -	$ -	$ -	$ -	$ -
OMS Integration with AMI	$ -	$ -	$ -	$ -	$ -
Volt VAr Optimization					
VVO	$ -	$ -	$ 9,051	$ 4,730	$ 13,781
Advanced Distribution Management System					
ADMS	$ -	$ -	$ -	$ -	$ -
DERMS	$ -	$ -	$ -	$ -	$ -
Field Area Network					
Field Area Network	$ -	$ -	$ -	$	$ -
Workforce Management					
Mobile Platform Damage Assessment	$ -	$ -	$ -	$ -	$ -
Admin & Regulatory					
Evaluation	$ -	$ 10,625	$ 12,307	$ 19,582	$ 42,514
Total					
Total	$ -	$ 10,625	$ 21,358	$ 24,312	$ 56,295

Table 2 – Planned Versus Actual Incremental O&M Spending

In the Department's March 11, 2021 memorandum, Section II.B directs each Company to report capital costs and operations and maintenance ("O&M") costs as distinct components of spending in each grid modernization plan year, to categorize capital costs by capitalized labor costs and non-labor capital costs and, if the sum of capital costs and O&M costs is less than the total annual reported spending, explain the discrepancy.

The Company worked collaboratively with the other EDCs to develop a common template for reporting O&M costs for the years 2018-2021. Reference Tab 5d of the Company's D.P.U. Appendix 1 for plan 2018-2021. 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 and 2021 the Company incurred costs within VVO for incremental software licensing fees as well as charges associated with the evaluation plan conducted by Guidehouse and other professional services completed by GDS Associates. Overall the Company's O&M spending continues to be lower than projected due to the timing of project implementation.

1.4 SIGNIFICANT TERM COST VARIANCES

The Company made the decision to align the FAN, ADMS, SCADA, and VVO projects. This approach has proven to be more efficient, though it has led to some delays in project implementation. The most significant delay in project implementation is the design of the segregated ADMS network required to ensure cyber security, which delayed the associated projects as well.

For the Company's VVO investment, actual spend is lower than estimated in our 2020 Grid Mod Annual report. The delay in project spending is associated with the project timing. In general, the Company expects that Townsend, Lunenburg, and Summer Street are among the most expensive substations at which to deploy VVO due to equipment needs, but expects costs will be in line over the remainder of the 10-year planned term.

The Company's original plan contemplated ADMS spending to start in the third year of the plan. Based on the award 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 the FG&E territory. Project spending has been less than expected due to the delay in the project schedule as described above. The Company expects the ADMS to be 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 from vendors for FAN 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 the Company's electric service franchise area in Massachusetts. In 2021, the Company began the testing, deployment and commissioning phase associated with Townsend substation VVO project. 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 lower in the later years. Overall, the Company expects the FAN project costs to be in line with the original estimate.

Also identified in Table 1 above 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. 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 lower than the original estimate.

2 PROGRAM IMPLEMENTATION

The Company has developed an organizational structure, project management and project approval and tracking process that relies 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. 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 necessary 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(s). The project leads provide updates on their individual projects at the Steering Committee meetings as well as provide updates and data for this report.

The Company has been implementing its GMP primarily with internal resources along with minimal contract resources for the FAN and ADMS projects. The Company has hired one incremental FTE to focus on the IT requirements of the FAN project. This individual is responsible for the communications settings, troubleshooting, and overall monitoring of the FAN.

2.2 COST AND PERFORMANCE TRACKING MEASURES

The Company decided that it would be most efficient to use the same budgeting and construction authorization approval process used 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 Construction Work Order ("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 2021.

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 second step in the approval process 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 may 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 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.

The processes set in place by the Company are designed to ensure that traditional spending and grid modernization spending are not intermingled. The Company learned very early that capital spending for grid modernization projects required individual authorizations and CWO numbers to allow for cost control and management. O&M

related spending also requires individual account numbers that have been identified for grid modernization. The Company found this is the most accurate means for separating and controlling grid modernization spending.

3 TERM IMPLEMENTATION SYSTEM LEVEL NARRATIVE BY INVESTMENT CATEGORY

This section of the report provides details for each GMP investment category the system level. 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 ordered the Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the 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 Companies. On December 1, 2020, the Companies 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 2021 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 2022.

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. To facilitate this effort, the Company developed a ranking system to prioritize which substations provide the largest benefits to customers and should, therefore, 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. 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 GMP 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 that may only need small modifications to achieve the required functionality, this 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 lower than the first two because, while it is still a very important aspect, it 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 benefits. The Company ranks the last two factors evenly, as they both provide benefits 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 automated 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 installing a SCADA terminal unit at the site, interconnecting the terminal unit with local devices and sensors, establishing communications between the terminal unit and the remotely-located SCADA Master system, and completing the associated programming to implement the desired SCADA functions.

At the start of the GMP, SCADA was already implemented to some extent at some of the Company's substations, and not at all at others. Furthermore, at many substations that had some level of existing SCADA capability, it was incomplete to the extent intended under the GMP. Therefore, the SCADA project in the GMP is adding SCADA at those substations that do not presently have it, and expanding SCADA capabilities at other substations where the functionality may be incomplete.

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

3.1.1.1.1 Performance on Implementation/Deployment

The SCADA project set out to perform additions or expansions at five (5) substations over the course of years 2018 through 2021. The Company has completed these SCADA implementations for the first four (4) of those substations (Rindge Road, Townsend, Beech Street and Lunenburg), and the implementation at the fifth substation (Princeton Road) was in progress at the end of 2021. While the SCADA implementation at this fifth substation was initially slated to be completed in 2021, work was deferred into the following year to redirect SCADA engineering resources to support the ADMS and VVO projects. Table 7 provides the actual versus planned implementation and spending.

	Overall Project Spending			
SCADA	2018	2019	2020	2021
Capital	$ -	$ 215,012	$ 608,203	$ 76,050
O&M	$ -	$ -	$ -	$ -

Table 7 – SCADA Spending

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 have been necessary to achieve the levels of functionality and measurement requirements now established for the other grid modernization projects and metrics.

3.1.1.1.3 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 reduce each whole-circuit outage by 10 minutes.

3.1.1.1.4 Description of Capability Improvement by Capability/Status Category

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

3.1.1.1.5 Key Milestones

Full SCADA implementation was placed into service for Rindge Road substation in 2019 and Townsend, Beech Street and Lunenburg substations in 2020. Full SCADA implementation for Princeton Road substation commenced in 2021, and is planned to be completed in 2022.

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 extend 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.

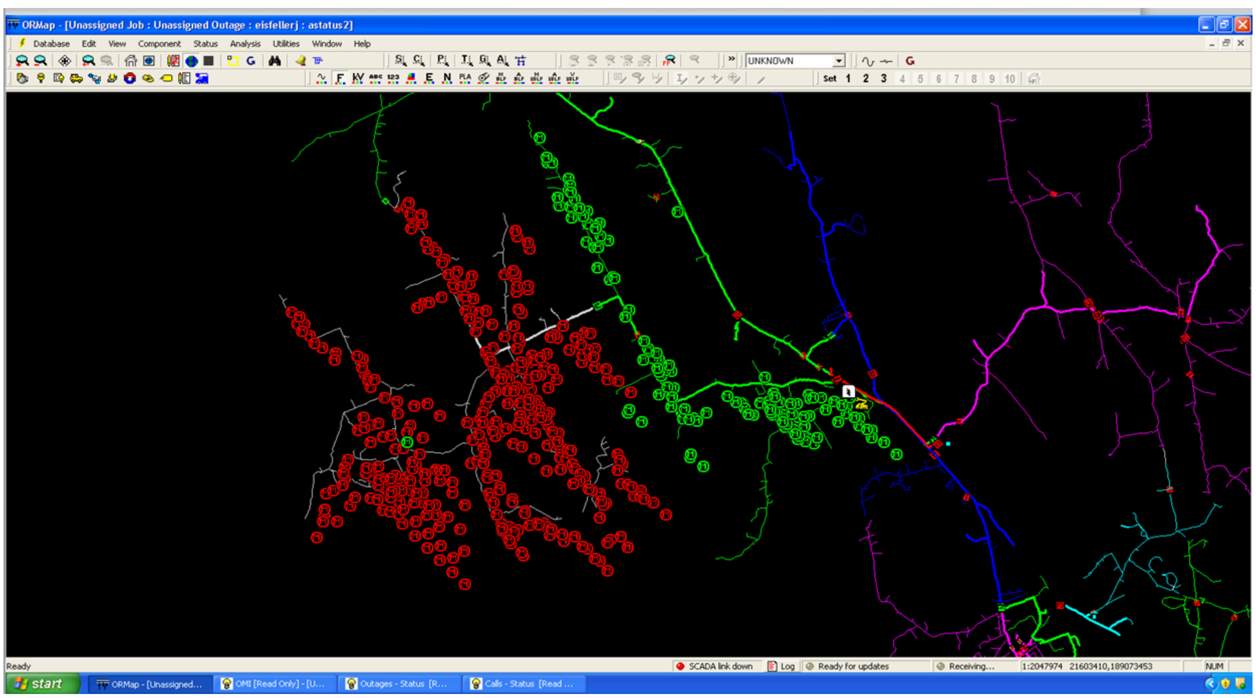

Figure 1: Unitil’s AMI Meters in OMS

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 the Company's Landis & Gyr AMI system is able to detect and report on meter/ endpoint level outages, the results 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, the Company makes 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 to improve the 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.

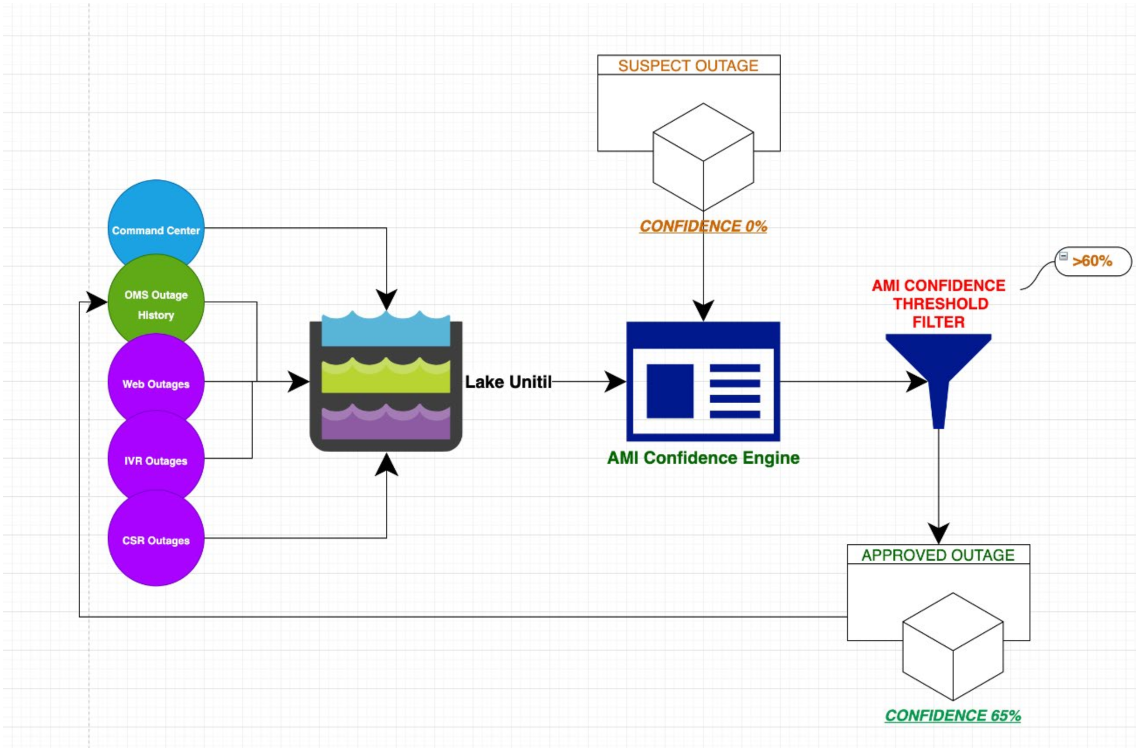

Figure 2: AMI/OMS Phase 1 Diagram

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 Performance on Implementation/Deployment

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

Table 8 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 Spending			
OMS Integration with AMI	2018	2019	2020	2021
Capital	$ -	$ 22,800	$ 57,136	10,785
O&M	$ -	$ -	$ -	$ -

Table 8 – OMS Integration with AMI Spending

Note: This is a software project the Company has decided to deploy 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%.

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, Unitil's 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 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. The Company expects that the AMI system on average will be five (5) minutes faster than customer calls for 10% of outages.

3.1.1.2.4 Description of Capability Improvement by Capability/Status Category

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.

3.1.1.2.5 Key Milestones

In 2021, testing of the middleware application for accuracy and completeness was started but not completed. In addition, initial user interface work was completed on a dashboard and reporting web application. Integration complications with the new ADMS and OMS secure environments have forced a temporary hold on additional work. As work on those new environments continues to evolve, Unitil is working to develop a strategy that will allow the data access required for this initiative without sacrificing any critical cyber security needs. Unitil plans to be live with this system in 2022.

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.

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.

3.1.2.1 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 (sensors) will also be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized centrally by the ADMS. The communication between the ADMS and the VVO controls will be designed and installed as part of the SCADA and FAN projects. The design requirements of the VVO system will be coordinated with the plans of the ADMS, SCADA, and the FAN.

3.1.2.1.1 Performance on Implementation/Deployment

After investigation of functionality of the ADMS, the equipment specification and purchasing of the VVO project commenced in 2019. 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. Equipment purchasing has been committed and paid for multiple substations, and the VVO equipment was installed and commissioned with communications for the Townsend substation in 2021. Full centrally controlled VVO functionality has not yet been tested through the ADMS. This testing is planned to be completed in 2022. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

The original plan based the cost estimates on the 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. The estimated planned cost and actual cost are listed below.

	Overall Project Spending			
VVO	2018	2019	2020	2021
Capital - Actual		$ 10,369	$ 1,787,195	$ 730,299
O&M	$ -	$ -	$ 9,051	$ 4,730

Table 9 – VVO Spending

3.1.2.1.2 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 evaluated two basic approaches to implementing a VVO system (model based and measurement based) and 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.

3.1.2.1.3 Description of Benefits Realized as the Result of Implementation

The VVO system operates by constantly seeking 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, thereby reducing their bills.

3.1.2.1.4 Description of Capability Improvement by Capability/Status Category

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.

3.1.2.1.5 Key Milestones

The Company has identified the existing field devices and controls that will need to be replaced to implement a VVO system and has developed the following replacement plan using the prioritized model that is described above as a guide. In addition to the existing devices, installation of new monitors, voltage regulators, and capacitor banks 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 material purchasing and installation for each substation will be over multiple years. The year listed below indicates the expected year that the equipment will be installed and VVO implemented.

Year	Substation	LTC Controls	Volt Regulator Controls[2]	Cap Bank Controls	Sensors[3]
2021	Townsend	1	6	4	12
2022	Summer Street	1	16	4	36
2023	Lunenburg	0	30	4	25
2024	West Townsend	1	11	6	14
2024	Beech Street	1	3	6	18
2025	Pleasant Street	1	11	10	22
2025	Princeton Road	2	1	7	8
2026	Sawyer Passway	2	19	27	22
2027	Nockege	1	8	1	0
2027	Canton Street	2	6	6	18
2028	River Street	1	5	7	7
2028	Rindge Road	0	10	0	6

Table 10 – VVO Field Equipment Estimates

3.1.3 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.

3.1.3.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

This project will consist of upgrading the Company's current OMS to an ADMS that will support VVO and unbalanced loadflow 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, 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

[2]Until 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.

[3] Until 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.

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.

3.1.3.1.1 Performance on Implementation/Deployment

This project began in 2019. Unitil implemented an ADMS test system and modelled and implemented unbalanced loadflow on one substation and three circuits in the test environment in 2020 utilizing basic load allocation and substation SCADA telemetry.

In 2021, Unitil placed the ADMS and ADMS SCADA production environments along with the secure IT network which they operate in service. Additionally in 2021, significant effort was required incorporate the Townsend distribution VVO metering equipment and behind the meter (net-meter) DER into the unbalanced loadflow modelling as well as to addresses unforeseen challenges. Although not completed by the end of 2021 in early 2022 the Company successfully implemented unbalanced loadflow on Townsend substation and its associated distribution circuits utilizing VVO meter point data for load allocation and behind the meter DER. This includes the "real-time" estimation of behind the meter DER generation based on SCADA telemetry data of large DER facilities. Unitil continues to transition to using customer hourly profile data for load allocation, creating the necessary reporting and custom control schemes to manage VVO, and to overcome other VVO development challenges. Unitil anticipates the full implementation of ADMS VVO on the Townsend distribution circuits in the 2nd quarter of 2022. This effort is expected to set the stage to allow Unitil to deploy unbalanced loadflow on the remaining circuits by the end of 2023.

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. Based on the award vendor's proposal, the FG&E cost of the ADMS is expected to be approximately $850,000 from 2020-2023 (as opposed to $2.1 million) with additional expenditures expected in years 2024-2027 to accommodate the implementation of VVO throughout the FG&E territory.

	Overall Project Spending			
ADMS	2018	2019	2020	2021
Capital	$ -	$ -	$ 172,724	$ 161,853
O&M	$ -	$ -	$ -	$ -

Table 11 – FG&E ADMS Spending

Note: The costs shown are only the costs associated with FG&E.

3.1.3.1.2 Lessons Learned/Challenges and Successes

The Company's biggest ADMS success in 2021 was the completion of the ADMS secure IT network and transitioning the ADMS/OMS application from the corporate network to the secure network. The ADMS secure IT network does not normally have access to the corporate network or internet and required the development of several new firewall rules and modifications to several system integrations. Additionally, Unitil ADMS users tested different network access methods to determine which method would provide the necessary functionality and performance. While this part of the project is complete, due to the number of firewall rules and integrations, it took significantly more time to transition OMS/ADMS to the secure network than originally anticipated. A penetration test of the ADMS secure IT network was performed in 2021 and the vendor performing the test was unable to gain access to the secure network.

The addition and configuration of new devices for use with ADMS unbalanced loadflow and VVO has taken significantly longer than expected. In many cases it took several weeks for the integration of each new device type (regulator, meter point, capacitor) in ADMS. This ended being an iterative process in which changes were required in the raw GIS definitions for the devices and each device type had to be handled differently. Now that each device type has been configured, Unitil is not expecting this to be a challenge moving forward.

The Company is working through unforeseen challenges with the functionality of device heartbeats and VVO. Unitil elected to utilize heartbeat mode for regulators and LTCs for VVO to reduce the possibility of voltage violations in the event communications to a device is lost. However, this leads to challenges due to the differences in how regulator controls and LTC currently function. Significant time was needed to test both the regulator and LTC controls to gain detailed knowledge of how the devices function when in heartbeat mode. The results of this testing identified the need to develop custom schemes to keep the heartbeat timers active and have both types of controls operate in similar fashions. Once complete, Unitil plans to use the same schemes for future substations and does not expect these challenges to impact future installations.

When configuring VVO, Unitil quickly realized that custom routines, reports and SCADA displays would be required to allow users to efficiently operate and monitor VVO. This required the Company to develop specification for the control routines and detail the requirements of the necessary reports. These routines and reports are expected to be completed in the first half of 2022.

The Company is implementing a model based VVO system that relies heavily on system configuration data. During the deployment process, the Company has learned that workflows will need to be modified/developed to expedite GIS and SCADA updates. Additionally, in many cases these changes need to be made in tandem as GIS needs to be updated with the correct SCADA information to allow the SCADA data to be utilized by ADMS.

Based on the information gathered in 2021, Unitil believes that it will require significantly more visibility and control of the DERs that will participate in the DERMS program including real-time invertor status, real and reactive power output, and voltage information. In the cases of energy storage, Unitil will also need real-time information on available storage and dispatch control over the energy storage facility.

Additionally, through the deployment of additional ADMS functionality and DERMS, the Company plans to assess the need for additional metering infrastructure. The Company's current AMI system does not have the capability to provide "real-time" customer metering information. The Company is currently utilizing a relationship it has developed between large scale PV with "real-time" SCADA telemetry and behind the meter PV without "real-time" metering information to estimate "real-time" PV output of behind the meter PV. As energy storage is deployed at existing sites or new sites "real-time" metering information of the energy storage could be integral to maintaining accurate ADMS models. Real-time metering could also be required at customers with very dynamic/unpredictable load profiles (e.g. EV chargers, stand-by service customers).

3.1.3.1.3 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.

3.1.3.1.4 Description of Capability Improvement by Capability/Status Category

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

3.1.3.1.5 Key Milestones

The Company has placed the ADMS and ADMS secure IT network into production and continues to implement unbalanced load flow and VVO functionality. The Company has completed the necessary population of technical data required for unbalanced loadflow, short circuit and VVO in GIS and also all necessary system (GIS, OMS, CIS and SCADA) functioning in the production environment of customer load profile data.

Early this year, the Company successfully implemented unbalanced loadflow on Townsend substation and its associated distribution circuits utilizing multiple primary metering locations for load allocation. The modeling and estimation of behind the meter DER facilities was also completed.

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.

- 5/1/2022 – Townsend Unbalanced Loadflow and VVO Implantation Complete
- 9/2/2022 – Summer Street Unbalanced Loadflow Implantation and Ready to Support VVO Complete
- 12/2/2022 – Switch Order Module Implementation Complete
- 5/1/2023 – Remaining FG&E Circuits Unbalanced Loadflow Implantation Complete (VVO and SCADA transition per VVO and SCADA transition schedules)

3.1.3.2 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 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.

3.1.4 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.

3.1.4.1 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 a foundational technology.

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, distribution automation and DER management.

3.1.4.1.1 Performance on Implementation/Deployment

To date, the FAN modem orders have been received. The primary and secondary backhaul circuits have been installed. The FAN secure access environment has been built at the primary site in Exeter, New Hampshire and the secondary site in Hampton, New Hampshire. The focus in 2022 is to install cell modems along with implementation of VVO and SCADA.

The Company's GMP estimated a level funded project over the 10 year GMP timeframe. The Company now expects that the project costs will not be as level as previously expected. The Company completed 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 FAN estimates and project plan to coincide with SCADA and VVO projects.

	Overall Project Spending			
Field Area Network	2018	2019	2020	2021
Capital	$ -	$ 107,057	$ 324,556	$449,818
O&M	$ -	$ -	$ -	$ -

Table 12 – FAN Spending

3.1.4.1.2 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.

3.1.4.1.3 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 monetized benefits. However, the VVO system cannot provide the benefits identified without a FAN.

3.1.4.1.4 Description of Capability Improvement by Capability/Status Category

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.

3.1.4.1.5 Key Milestones

Below are some of the key milestones for the deployment of the FAN.

- 3/31/2020 RFP Proposals due
- 4/23/2020 Award vendor
- 5/14/2020 Project initiated, design work begins
- 2/22/2021 Primary FAN backhaul circuit commissioned
- 7/15/2021 Secondary FAN backhaul circuit commissioned
- Cell Modems will be installed according to the VVO and SCADA implementations

3.1.5 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.

3.1.5.1 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.

3.1.5.1.1 Performance on Implementation/Deployment

The Company established a project team that 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 met or exceeded requirements and were contacted for a demo of their product. Tier 2 vendors may have met most of the requirements or require additional development but would still be considered. Tier 3 vendors either did not meet all requirements or had other constraints that may affect their ability to provide a suitable solution.

The evaluation criteria developed for this project 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 was considered for a series of product demonstrations. An evaluation model was developed to rank the vendors.

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 obtain a clearer understanding of their proposal and have questions answered. Following the vendor presentations, the evaluation matrix was updated.

The Company 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.

The Company completed its review of the statement of work and execution of contract documentation and began this project in January of 2021. Initially, the Company expected development to take place through Q2 with final project completion estimated in September 2021. However, due to development challenges and resource constraints is now expected to be completed in Q2 of 2022. Information on performance will be provided in the next annual report and as part of the Evaluation Plan.

The project team 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 Spending			
Mobile Platform Damage Assessment	2018	2019	2020	2021
Capital	$ -	$ -	$ -	$ 272,192
O&M	$ -	$ -	$ -	$ -

Table 13 – Mobile Platform Damage Assessment Spending

Note: This is a software project the Company has decided to deploy 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%.

3.1.5.1.2 Lessons Learned/Challenges and Successes

Throughout this project, the Company learned that mobile damage assessment is just one of the functionalities that this software platform can provide. Other functionality includes asset management, inspections, or other workforce management tools with several proposals including many of these features as part of 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.

3.1.5.1.3 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.

3.1.5.1.4 Description of Capability Improvement by Capability/Status Category

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, and 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 where 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

3.1.5.1.5 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. Beginning in January 2021 members of the project team began working with the SSP team to implement the MIMS solution with the design and development phases being completed throughout Q2 and Q3 of 2021. Initially the MIMS software was scheduled to be installed and tested throughout Q3 and Q4 however was postponed to Q1 of 2022 due to development issues and resource constraints. Upon installation, testing and validation will begin with complete deployment of the solution by the end of 2022.

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; and 2) approved the Companies' proposed statewide and company-specific infrastructure metrics.

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 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 terms "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 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 14 – Classification of Grid Modernization Devices

4.1.2.3 Calculation Approach

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

Metric:

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

4.1.2.4 Results

The system automation saturation result at the end of year 2021 was calculated at 410.2 customers per automated device. Reference Appendix 2 for the substation and circuit level detail. The 2017 baseline for this metric was calculated at 674.8.

4.1.3 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.

4.1.3.1 Assumptions

The base-line for this metric is all pre-existing sensor installations on distribution circuits and substation circuit terminals as of December 31, 2017.

4.1.3.2 Calculation Approach

This infrastructure metric measures the percent of distribution circuits that have sensors installed, which should increase as sensors are deployed.

4.1.3.3 Results

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

	2017 Baseline	2021 Actual
Total number of Substations	13	13
Total number of Substations with Sensors	13	13
% of Substations with Sensors	100%	100%
Total number of Circuits	45	44
Total number of Circuits with Sensors	34	42
% of Circuits with Sensors	75.5%	95.5%

Table 15 – 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 to 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[4]	10	12	83%
OMS Integration with AMI[5]	0	1	0%
Volt/VAr Optimization			
VVO Capacitor Banks	5	5	100%
VVO Automated Voltage Regulators	6	6	0%
VVO Automated LTC	1	1	100%
Monitoring[6]	12	12	0%
ADMS			
ADMS	0	1	0%
DERMS	Under Review	Under Review	Under Review
Communications			
Field Area Network	22	120	22%
Workforce Management			
Mobile Platform Damage Assessment[7]	0	1	0%

Table 16 – Quantity of Devices by Investment

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

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 cost 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 2018-2021	Total cost of devices planned	Percent – Cost of devices installed / total cost of devices planned
Monitoring and Control			
SCADA	$ 899,265	$1,062,561	85%
OMS Integration with AMI (Note 1)	$ 90,721	$ 129,936	70%
Volt/VAr Optimization			
VVO Capacitor Banks	$ 687,161	$ 1,165,004	60%
VVO Automated Voltage Regulators	1,310,245	$ 2,464,728	53%
VVO Automated LTC	$ 33,082	$ 53,082	62%
Monitoring	$ 497,374	$ 1,432,948	35%
Advanced Distribution Management System			
ADMS	$334,577	$850,000	39%

DERMS	$0	$0	0%
Communications			
Field Area Network	$828,659	$1,161,461	31%
Workforce Management			
Mobile Platform Damage Assessment (Note 1)	$ 272,192	$650,000	42%

Table 17 – Total Capital Costs of Devices Planned

Note 1: This is a software project the Company has decided to deploy 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%. Although, ADMS is a software project, the costs shown are only the costs associated with FG&E.

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 implementing grid modernization investments in 2021. 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. Therefore, the Company made the decision to not continue with the review, modification and implementation of the GMP because 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, while 2020 and 2021 have been focused on project implementation.

5 DISTRIBUTED ENERGY RESOURCES (DERS)

DER interconnections have been a focus of the Company and are 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 then faced the challenge of individual residential DER interconnections causing backflow through substations, 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 overvoltage protection.

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 October 22, 2020, the Department opened docket D.P.U. 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.

On November 24, 2021, the Department issued an order (D.P.U. 2-75-B) to establish a provisional program with a modified cost allocation and cost recovery methodology consistent with the public interest. Under this order, the EDCs were to implement the provisional program for DER planning and for the assignment and recovery of associated costs for applications that were undergoing an Affected Group Study. At the time, Unitil did not have any applications under an Affected Group Study.

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

5.1 OVERVIEW OF DERS ON DISTRIBUTION SYSTEM

As of year-end 2021, Unitil has 2,171 customer owned DER facilities and 1 utility owned solar facility. Of the customer facilities, 2,156 (99.3%) are solar and 10 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 43,017 kVA; approximately 46% of the 2021 system peak load of 93.9 kVA. The 2021 minimum net load of the FG&E system at the 115 kV interface, due to DER, was -11 kVA (flowing from the FG&E distribution system to the 115kV transmission system).

In addition to the facilities on-line, there were 256 facilities being processed for installation totaling an additional 25,787 kVA. Of these facilities in process, 246 facilities totaling 4,891 kVA are solar and 10 facilities totaling 20,896 kVA are solar with battery storage or storage only.

85% of the substation transformers on the FG&E distribution system could potentially experience reverse power flow at light load times if all of the projects in process are actually installed.

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 is triggered by 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 special 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 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 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 submitted 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 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 GMP.

In addition, the Department also ordered the Companies to develop a formal evaluation process, including an evaluation plan and evaluation studies, to review the 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 Companies 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 2022.

In compliance with the Department's Order, the Company has included the 2018-2021 Grid Modernization Term Report Template as Appendix 1 to this report as well as an update of each performance metric below.

Statewide Performance Metrics

SP-1	Volt Var Optimization and Conservation Voltage Reduction (VVO/CVR) Baseline
SP-2	Volt Var Optimization (VVO) Energy Savings
SP-3	VVO Peak Load Impact
SP-4	VVO Distribution Losses without AMF (Baseline)
SP-5	VVO Power Factor
SP-6	Estimated VV/CVR Energy and GHG Impact
SP-7	Increase in Substations with DMS Power Flow and Control Capabilities
SP-8	Control Functions Implemented by Circuit (VVO, Auto Reconfiguration)
SP-9	Numbers of Customers that benefit from GMP funded Distribution Automation Devices
SP-10	Reliability-Focused Grid Modernization Investments' Effect on Outage Duration
SP-11	Reliability-Focused Grid Modernization Investments' Effect on Outage Frequency
SP-12	VVO Related Voltage Complaints Performance Metric and Baseline
CP-1	Unitil Reliability-Related Company-Specific Performance Metric

6.1 STATEWIDE PERFORMANCE METRICS – BASELINES AND TARGETS

The following statewide performance metrics are used to measure progress towards grid modernization. In some cases, the Company is able to provide baseline 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. Each of the metrics proposed by the Company provides a summary of the baseline, targets, benefits and results

6.1.1 Volt/VAr Optimization and conservation voltage reduction (VVO/cvr) Baseline (SP-1)

6.1.1.1 Objective

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

6.1.1.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.1.3 Target

The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled.

6.1.1.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report. The Company plans to begin VVO testing on its Townsend circuits in Q2 2022.

6.1.2 Volt VAr Optimization (VVO) Energy Savings (SP-2)

6.1.2.1 Objective

Quantify the energy savings achieved by VVO using the baseline established for the circuit against the annual circuit load with the intent of optimizing system performance.

6.1.2.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.2.3 Target

The Company's benefit/cost model assumed a 2% reduction in energy consumption. The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled.

6.1.2.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report. The Company plans to begin VVO testing on its Townsend circuits in Q2 2022.

6.1.3 VVO Peak Load Impact (SP-3)

6.1.3.1 Objective

This metric is designed to quantify the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand. This impact metric provides a peak load impact of VVO for selected circuits and peak periods.

6.1.3.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.3.3 Target

The Company's benefit/cost model assumed a 2% reduction in energy consumption. The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled.

6.1.3.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report. The Company plans to begin VVO testing on its Townsend circuits in Q2 2022.

6.1.4 VVO Distribution Losses without AMF (Baseline) (SP-4)

6.1.4.1 Objective

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

Electrical loss in the circuit can be investigated using the difference between power provided by the circuit regulator and the total power delivered to the consumer loads. This impact metric presents the difference between circuit load measured at the substation via the SCADA system and the metered load measured through AMI.

6.1.4.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.4.3 Target

The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled.

6.1.4.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report. The Company plans to begin VVO testing on its Townsend circuits in Q2 2022.

6.1.5 VVO Power Factor (SP-5)

6.1.5.1 Objective

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

6.1.5.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.5.3 Target

The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled. The targets will be developed to operate the circuits as close to unity power factor as practicable.

6.1.5.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report.

6.1.6 Estimated VVO/CVR Energy and GHG impact (SP-6)

6.1.6.1 Objective

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

6.1.6.2 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company plans to use the measurement and verification process developed by Guidehouse to estimate the impact on system load. Baselines will be reported during the first annual report following the field measurement and verification.

6.1.6.3 Target

The Company's planned measurement and verification process will measure the system in three different states: (1) pre-circuit conditioning; (2) post-circuit conditioning with VVO disabled; and (3) post-circuit conditioning with VVO enabled. The target for this will be to reduce GHG emissions by 2% in line with the 2% reduction in energy consumption and peak demand.

6.1.6.4 Benefits and Results

As of this report, the Company does not have any VVO enabled circuits in the measurement and verification process, so there are no results to report.

6.1.7 Increase in Substations with DMS Power Flow and Control Capabilities (SP-7)

6.1.7.1 Objective

This metric will demonstrate the progress in the ADMS investment by tracking the substations that have been equipped with power flow capabilities. This metric will support the objective of optimizing system performance and more specifically improve asset utilization, improve reliability and integrate distributed energy resources. ADMS gives system operators increased visibility on the real time output of generating facilities. This metric is designed to demonstrate that the model is an accurate representation of field conditions.

6.1.7.2 Baseline

The baseline for this metric will start at zero since no feeders have been equipped with this technology. This metric will follow the Company's combined implementation of ADMS, VVO, SCADA and FAN on a substation by substation basis.

6.1.7.3 Target

The target for this metric based upon the Company's GMP will be to add one substation (3-4 circuits) per year. At the time of this report, the Company is initiating Townsend substation and circuits within its ADMS.

6.1.7.4 Benefits and Results

As of this report, the Company does not have any ADMS enabled circuits in production. The Company is initiating Townsend substation and circuits within its ADMS.

6.1.8 Control Functions Implemented by Circuit (VVO, Auto Reconfiguration) (SP-8)

6.1.8.1 Objective

This metric will show the progress in the ADMS investment by tracking the control functions implemented at the circuit level. This metric will support the objective of optimizing system performance and more specifically minimize electrical losses and improve reliability.

6.1.8.2 Baseline

The baseline for this metric will start at zero since no feeders have been equipped with this technology. This metric will follow the Company's combined implementation of ADMS, VVO, SCADA and FAN on a substation by substation basis.

6.1.8.3 Target

The target for this metric based upon the Company's GMP will be to add one substation (3-4 circuits) per year. At the time of this report, the Company is initiating Townsend substation and circuits within its ADMS and VVO.

6.1.8.4 Benefits and Results

As of this report, the Company does not have any ADMS enabled circuits in production. The Company is initiating Townsend substation and circuits within its ADMS and VVO.

6.1.9 Numbers of Customers that benefit from GMP funded Distribution Automation Devices (SP-9)

6.1.9.1 Objective

This metric will show the progress in the Distribution Automation investment by tracking the numbers of customers that have benefitted from the installation of Distribution Automation devices. This metric will support the objective of optimizing system performance and more specifically reduce the duration and number of customers impacted by outage events. These investments will also allow for a reduction in manual switching operations, reduce operations cost and potentially defer capital upgrades with enhanced flexibility to shift load.

6.1.9.2 Baseline

The baseline for this metric will start at zero since this will be tracking only the customers that benefit from Grid Modernization investments. A table with the type of device, circuit number where installed and number of customers benefitted will be provided to support the tracking of this metric.

6.1.9.3 Target

The target for this metric based upon the plan will be to add one substation (3-4 circuits) per year based upon the plan filed as part of the Company's GMP. This will have the impact of reaching 3,000 to 4,000 customers per year.

6.1.9.4 Benefits and Results

Tab 4d of the Company's D.P.U. Appendix 1 for 2018-2021 indicates that 11,331 customers (or 25% of the total number of customers) are served from a GMP funded automation device.

6.1.10 Reliability-Focused Grid Modernization Investments' Effect on Outage Durations (SP-10)

6.1.10.1 Objective

This metric will compare the experience of customers on GMP enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how automation can reduce the duration of outages.

6.1.10.2 Baseline

The metric will use the circuit three-year SAIDI average as the baseline. It will compare the SAIDI results of the plan year to the circuit's three-year historic average. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.10.3 Target

The target for this metric is to have the current year circuit level SAIDI (CKAIDI) to be less than the average of the CKAIDI of the preceding three years. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.10.4 Benefits and Results

Tab 3d of the Company's D.P.U. Appendix 1 for 2018-2021 compares reliability performance on a circuit by circuit basis and compares that to the baselines calculated in Tab 9 of the same appendix.

6.1.11 Reliability-Focused Grid modernization investments' effect on outage frequency (SP-11)

6.1.11.1 Objective

This metric will compare the experience of customers on GMP enabled circuits as compared to the prior three-year average for the same circuit. This metric will provide insight into how automation can reduce the frequency of outages.

6.1.11.2 Baseline

The metric will use the circuit three-year SAIFI average as the baseline for this metric. It will compare the SAIFI results of the GMP plan year to that three-year historic average. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.11.3 Target

The target for this metric is to have the current year circuit level SAIFI (CKAIFI) to be less than the average of the CKAIFI of the preceding three years. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.11.4 Benefits and Results

Tab 3d of the Company's D.P.U. Appendix 1 for 2018-2021 compares reliability performance on a circuit by circuit basis and compares that to the baselines calculated in Tab 9 of the same appendix.

6.1.12 VVO RELATED VOLTAGE COMPLAINTS (SP-12)

6.1.12.1 Objective

The primary focus of the VVO investments is to manage circuit voltages at a lower threshold while maintaining minimum voltage service requirements for all customers on a substation and circuit. Since VVO will be actively managing voltages, there is a desire to track and report on the potential for the introduction of VVO-related voltage complaints. There may be historical low voltage causes that exist outside of a customer's service connection and equipment. Certain voltage issues, such as those that are ultimately determined to have been caused by customer-owned equipment, will not be mitigated by the VVO investments.

6.1.12.2 Baseline

The metric will use the circuit three-year SAIFI average as the baseline for this metric. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.12.3 Target

The target for this metric is to have the current year voltage complaints to be less than the average of the voltage complaints of the preceding baseline period. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.12.4 Benefits and Results

VVO has not been enabled for any circuits, therefore there are no voltage complaints related to VVO.

6.1.13 Unitil Reliability-Related Company-Specific Performance Metric (CP-1)

6.1.13.1 Objective

The objective of this metric is to track the customer minutes savings per outage on each feeder through the use integrating AMI to OMS.

6.1.13.2 Baseline

The metric will use the circuit three-year average circuit level CAIDI as the baseline for this metric. Reference Tab 9 of the Company's D.P.U. Appendix 1 for 2018-2021.

6.1.13.3 Target

The Company's target is to save 5 minutes per outage once AMI is integrated with OMS.

6.1.13.4 Benefits and Results

The Company has not completed the integration of AMI to OMS. Therefore the customers have not begun to realize the benefits.

7 TERM SUMMARY OF 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 its GMP.

7.1 NON-WIRES ALTERNATIVES

The Company has implemented a utility scale PV installation and is currently in the process of installing a utility scale energy 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 (FG&E's 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

This Company installed 1.3MW Photovoltaic (PV) facility 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 4,430 MWh 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 ENERGY STORAGE

The Company placed into service a 2MW/4MWh energy storage facility 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 energy 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-wires 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 non-wires alternatives projects to defer this project. The project RFP was released to 19 potential bidders and the Company received four (4) bids all focused on PV or PV coupled with storage options. The result of the bid process was all of the bids were between 10-15 times more expensive than the traditional option even after taking into consideration all of the other benefits (i.e. energy produced, capacity offset, solar credits, etc.). In light of this disparity, the Company determined it was appropriate to implement the traditional solution.

The Company has rewritten its planning criteria to require that projects meeting 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.

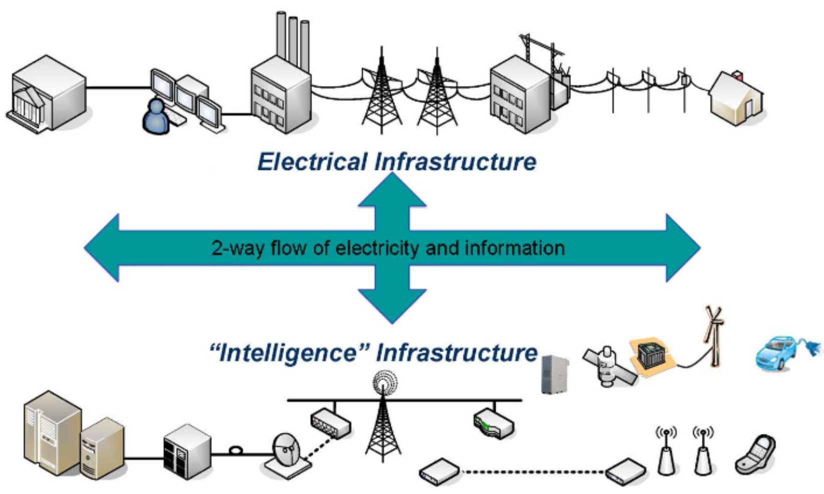

Figure 3: Electrical vs. Intelligence Infrastructure

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.

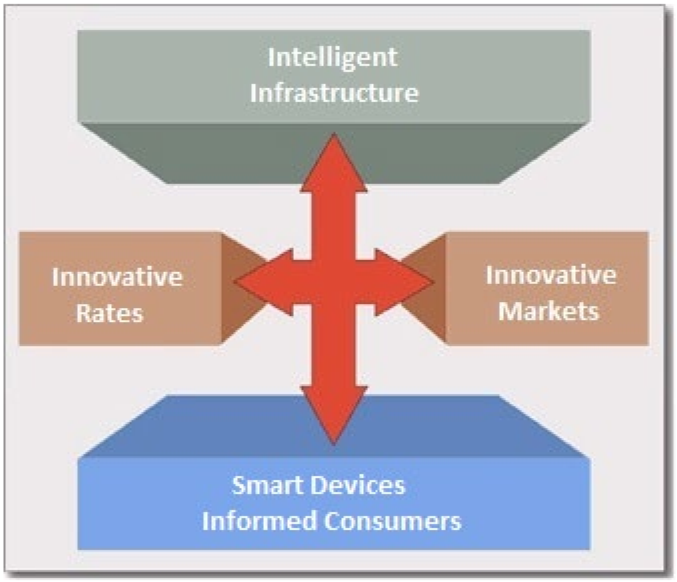

Figure 4: Enabling Markets

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

So 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 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 and 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 GMP. 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 term 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

2021 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	610	0	0	0	0	0	0	1	0	0	0	1	610.0
Beech Street	1W2	2,025	0	1	0	0	0	1	1	0	0	0	1	1,350.0
Beech Street	1W4	1,624	0	1	0	0	0	1	1	0	0	0	1	1,082.7
Beech Street	1W6	1	0	0	0	0	0	0	1	0	0	0	1	1.0
Beech Street		**4,260**	**0**	**2**	**0**	**0**	**0**	**2**	**4**	**0**	**0**	**0**	**4**	852.0
Canton Street	11H10	752	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11H11	375	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street	11W11	1,749	0	0	0	0	0	0	0	0	0	0	0	---
Canton Street		**2,876**	**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	1,523	0	0	0	0	9	9	1	0	0	0	1	276.9
Townsend	15W17	577	0	0	0	0	1	1	1	0	0	0	1	384.7
Townsend		**2,101**	**0**	**0**	**0**	**0**	**10**	**10**	**4**	**1**	**0**	**0**	**5**	210.1
Nockege	20W22	906	1	0	0	0	0	1	0	0	0	0	0	1,812.0
Nockege		**906**	**1**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	1,812.0
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	2,095	0	0	0	0	0	0	1	0	0	0	1	2,095.0
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		**2,601**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**0**	**0**	**0**	**8**	325.1
River Street	25W27	1,228	0	0	0	0	0	0	1	0	0	0	1	1,228.0
River Street	25W28	627	0	0	0	0	0	0	1	0	0	0	1	627.0
River Street	25W29	1	0	0	0	0	0	0	1	0	0	0	1	1.0
River Street		**1,856**	**0**	**0**	**0**	**0**	**0**	**0**	**3**	**0**	**0**	**0**	**3**	618.7
Lunenburg	30W30	1,363	0	0	0	0	0	0	1	0.5	0	0	2	908.7
Lunenburg	30W31	1,677	0	2	0	0	0	2	1	3	0	0	4.0	335.4
Lunenburg		**3,040**	**0**	**2**	**0**	**0**	**0**	**2**	**2**	**3.5**	**0**	**0**	**5.5**	467.7
Pleasant Street	31W34	1,261	0	0	0	0	0	0	1	0	0	0	1	1,261.0
Pleasant Street	31W37	1,247	0	0.5	0	0	0	0.5	1	7.5	0	0	8.5	142.5
Pleasant Street	31W38	1,326	0	2	0	0	0	2	1	1	0	0	2	442.0
Pleasant Street		**3,834**	**0**	**2.5**	**0**	**0**	**0**	**2.5**	**3**	**8.5**	**0**	**0**	**11.5**	300.7
Rindge Road	35W36	790	0	0	0	0	0	0	1	3	0	0	4	197.5
Rindge Road		**790**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**	**0**	**0**	**4**	197.5
West Townsend	39W18	1,970	0	0	0	0	0	0	1	4	0	0	5	394.0
West Townsend	39W19	1,331	0	1	0	0	0	1	1	1	0	0	2	532.4
West Townsend		**3,301**	**0**	**1**	**0**	**0**	**0**	**1**	**2**	**5**	**0**	**0**	**7**	440.1

2021 EOY

Substation	Circuit	Customers	Partially Automated Devices: Feeder Breakers [Note 1]	Partially Automated Devices: Distribution Reclosers, etc. [Note 2]	Partially Automated Devices: Padmount Switchgear	Partially Automated Devices: Network Transformers/ Protectors	Partially Automated Devices: Capacitors & Regulators [Note 3]	Partially Automated Device Sub-Totals	Fully Automated Devices: Feeder Breakers [Note 1]	Fully Automated Devices: Distribution Reclosers, etc. [Note 2]	Fully Automated Devices: Padmount Switchgear	Fully Automated Devices: Network Transformers/ Protectors	Fully Automated Device Sub-Totals	System Automation Saturation
Summer Street	40W38	3	0	0	0	0	0	0	1	0	0	0	1	3.0
Summer Street	40W39	430	0	0	0	0	0	0	1	1	0	0	2	215.0
Summer Street	40W40	1,574	0	3.5	0	0	0	3.5	1	0	0	0	1	572.4
Summer Street	40W42	1,785	0	0	0	0	0	0	1	1	0	0	2	892.5
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		**3,792**	**0**	**3.5**	**0**	**0**	**0**	**3.5**	**6**	**2**	**0**	**0**	**8**	388.9
Princeton Road	50W51	656	0	0	0	0	0	0	1	0	0	0	1	656.0
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		**997**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**0**	**0**	**0**	**5**	199.4
	Total Customers	**30,355**					**Total Partially Automated Devices**	**22**				**Total Fully Automated Devices**	**63**	**410.2**

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.
Single controls for multi-phase banks are counted as one.

Note 3: Does not include substation capacitor banks, transformer LTCs or bus regulators.
Single-phase regulator controls are counted individually, even if regulators are part of a multi-phase bank.

Appendix 3

Number/Percentage of Circuits with Installed Sensors

2021 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	9	9	0	4	23
Townsend	15W17	1	0	0	0	0	0	1	3	0	2	7
Townsend		**4**	**1**	**0**	**0**	**0**	**0**	**10**	**12**	**0**	**6**	**33**
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	0.5	0	0	0	0	0	0	0	3	4.5
Lunenburg	30W31	1	3	0	0	0	0	0	0	0	1	5
Lunenburg		**2**	**3.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**9.5**

2021 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
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	**13**
Total number of Substations with Sensors	**13**
% of Substation with Sensors	**100.0%**
Total number of Circuits	**44**
Total number of Circuits with Sensors	**42**
% of Circuits with Sensors	**95.5%**

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.