Electric Sector Modernization Plan

September 2023

Unitil

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Acronyms

AC – Alternating Current

ACEEE - American Council for an Energy-Efficient Economy

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure

API – Application Programming Interface

BEA - Bureau of Economic Analysis

BTM – Behind the Meter

BTU – British Thermal Unit

C&I – Commercial and Industrial

CECP – Massachusetts Clean Energy and Climate Plan

CESAG - Community Engagement Stakeholder Advisory Group

CIS – Customer Information System

CMI – Customer Minutes of Interruption

CPP – Critical Peak Pricing

DA – Distribution Automation

DEI – Diversity, Equity and Inclusion

DER – Distributed Energy Resource

DERMS – Distributed Energy Resource Management System

DG – Distributed Generation

DPU – Department of Public Utilities

DTH - Dekatherm

EDC – Electric Distribution Company

EE – Energy Efficiency

EEI – Edison Electric Institute

EFSB – Energy Facilities Siting Board

EJ – Environmental Justice

EJC – Environmental Justice Community

ERP – Emergency Response Plan

ESMP – Electric System Modernization Plan

ESS – Energy Storage System

EV – Electric Vehicle

EVSE - Electric Vehicle Supply Equipment

FAN – Field Area Network

FERC – Federal Energy Regulatory Commission

FLISR – Fault Location, Isolation, and Service Restoration

FTM – Front of the Meter

GHG – Greenhouse Gas Emissions

GIS – Geographic Information System

GMAC – Grid Modernization Advisory Council

GPS – Global Positioning System

GMP – Grid Modernization Plan

HVAC – Heating, Ventilation and Air Conditioning

IVM – Integrated Vegetation Management

ISO-NE – Independent System Operator – New England

IVR – Integrated Voice Recognition

kV – kilovolt (1,000 Volts)

kW – kilowatt (1000 Watts)

LTC – Load Tap Changer

MA-DOT – Massachusetts Department of Transportation

MW – Megawatt (1,000,000 Watts)

N-1 – Planning term used signify the removal of one element from the analysis

NWA – Non-Wire Analysis

OMS – Outage Management System

PLC – Power Line Carrier

PLX – Gridstream PLX Technology

PPC – Poor Performing Circuit

PV – Photovoltaic

RIMS II - Regional Input-Output Modeling System

RCP – Representative Concentration Pathways

RFP – Request for Proposal

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SCADA – Supervisory Control and Data Acquisition

SER – System Event Review

SMG – Senior Management Group

SPC – Strategic Planning Committee

SQ. FT. – Square Feet

SRP – Storm Resiliency Program

TOU – Time of Use

VAr – Volt Ampere Reactive

VPP – Virtual Power Plant

VVO – Volt VAr Optimization

UBLF – Unbalanced Load Flow

W - Watt

WTHI – Weighted Temperature-Humidity Index

1 EXECUTIVE SUMMARY

Fitchburg Gas and Electric Light Company d/b/a/ Unitil (hereinafter referred to as "Unitil" or "the Company") provides this Electric Sector Modernization Plan (hereinafter referred to as "Plan" or "ESMP") subsequent to the regulations set forth in Massachusetts General Laws Chapter 164 Section 92B – 92C effective August 11, 2022.

The electric system as it is designed today is not prepared for the level of electrification and interconnection of distributed energy resources identified in the Commonwealth's pathway to decarbonization. Investment in the electric system will focus on the overall capacity as well as technological improvements to facilitate an optimized electric system. The long range forecast focuses the investments where they provide the most benefit.

This Plan details the Company's approach to proactively upgrading its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the Commonwealth realize its greenhouse gas emission limits.

The Plan is designed to help the Commonwealth realize its Greenhouse Gas Emission ("GHG") limits and as such, the Plan accounts for the Company's share of achieving the goals. This Plan supports a transparent planning process to enable all uses of the electric system while maintaining flexibility to alter the plan to address future challenges that have not yet been identified. The plan provides a 5 year forecast, 10 year forecast and a demand assessment through 2050 to account for future needs.

Climate change is having an effect of increased temperatures and more frequent severe weather events. Resiliency improvements are required to meet these challenges and reduce the impact of major outages to our customers and the communities we serve.

The goal of the ESMP is to implement a transparent planning process ensuring the benefits of the plan are distributed in an equitable manner with special attention to providing benefits to environmental justice communities and historically disadvantaged communities.

1.1 VISION: ENABLING A JUST TRANSITION TO A RELIABLE AND RESILIENT CLEAN ENERGY FUTURE

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. For over a decade, the Company 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. The Company's vision is to transform the way people meet their evolving energy needs to create a clean and sustainable future.

A just transition to a clean energy future means the electric system is designed to meet the needs of all users while not disadvantaging individual or group of customers. The Company will work with our customers, communities and stakeholders to develop electric system plans and approaches to mitigate environmental impacts, support those impacted the most and help the Commonwealth realize its greenhouse gas ("GHG") emission limits.

The desire to reduce GHG emissions has driven a transformation of the energy sector. Significant and meaningful investments in clean energy and efficient end-use technologies have led to a decline in GHG emissions. Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets and innovative home energy technologies. Advancements in technology are reducing the cost of clean energy, making it more affordable for consumers. Energy markets continue to evolve 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 ("DERs") are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system 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 efficiently participate in energy markets, 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 enabling 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.

1.2 PLAN OVERVIEW AND ALIGNMENT WITH THE CLEAN ENERGY AND CLIMATE PLAN

The 2050 Clean Energy and Climate Plan (CECP) is the Commonwealth's plan to achieve economy-wide net zero greenhouse gas emissions by 2050. The ESMP is Unitil's plan to maintain an electric network that anticipates and meets the needs of significant increases in distributed energy generation, transportation electrification, and increased consumption from policies driving electrification, thereby contributing to the goals of the CECP.

The format of the Plan has been developed with input from the Grid Modernization Advisory Council ("GMAC"). A consistent format for all of the EDCs facilitates an efficient review process. Section 2 of the report describes how this plan complies with the requirements outlined in the 2022 Climate Act. Section 3 provides recommendations for a consistent approach to a stakeholder management process. Section 4 provides some background on the existing electric system as well as some information on technology platforms currently in use. Section 5 describes the 5- year and 10-year electric load forecast and demand assessment used as a basis for ensuring the system is designed to meet future demand.

Section 6 provides the system constraints and proposed solutions to those system constraints over the 5-year and 10-year terms. This section also provides a summary of the Company's base investments, previously approved investments and new investments proposed as part of this plan. Section 7 provides a summary of the 5-year investment plan. Section 8 describes the Company's approach and assumptions used to develop the 2035-2050 demand assessment.

Section 9 provides the system constraints and proposed solutions to those system constraints 2035-2050 timeframe.

Section 10 provides the Company's approach to assessing and planning for the effects of climate change. Section 11 provides an integrated approach to electric and gas distribution system planning. Section 12 describes how this plan will impact the workforce and provide economic and health benefits to our communities. Section 13 provides a summary of the plan as well as a discussion of metrics development and next steps.

1.3 SERVICE TERRITORY OVERVIEW (CUSTOMERS, LOAD, TRANSMISSION, DISTRIBUTION, GENERATION)

The Company's electric service territory include the towns of Lunenburg, Townsend and Ashby and the city of Fitchburg all located in north-central Massachusetts. The Company provides service to approximately 26,500 residential customers and approximately 4,000 commercial and industrial customers.

The Company's gas service territory overlaps the electric service territory in Fitchburg, Ashby, Townsend and a portion of Lunenburg. The Company also provides gas service to the town of Westminster and the City of Gardner. The Company provides service to approximately 14,500 residential customers and approximately 1,700 commercial and industrial customers.

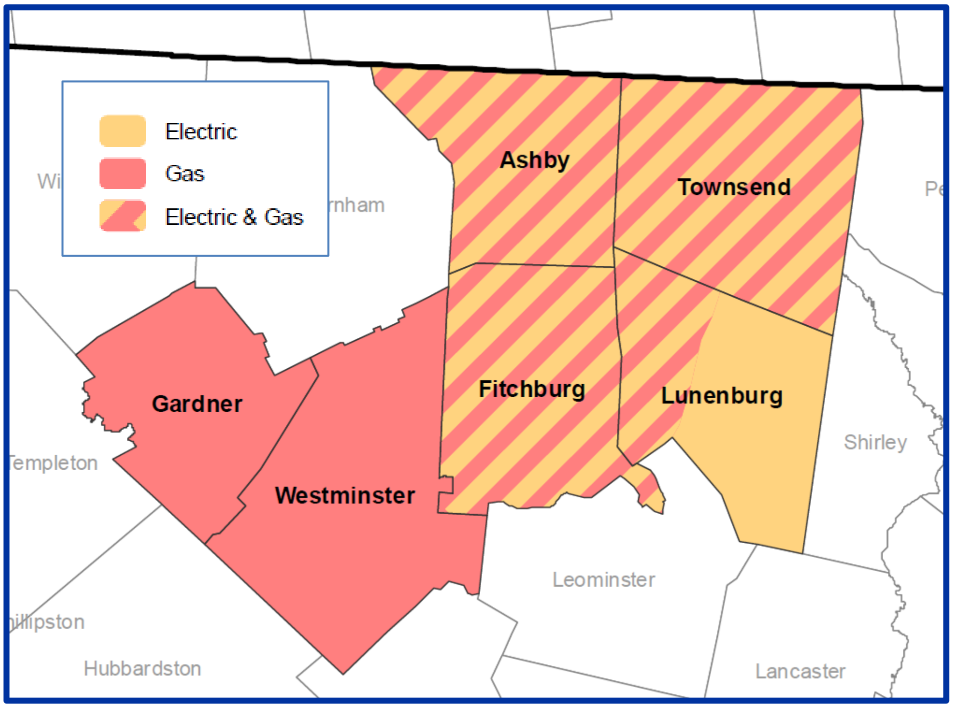

Figure 1 - Unitil's Electric and Gas Service Territory

The Company's electric power system takes transmission service from National Grid's 115 kV transmission system at Flagg Pond substation, located in southwest Fitchburg. Flagg Pond substation consists of a 115 kV high side ring bus, two 115 - 69 kV, 60/80/100 MVA autotransformers, and a 69 kV low side ring bus.

A wood burning non-utility generating facility connects into the system at the Flagg Pond 69 kV ring bus. The facility historically supplies between 12-18 MW to the system.

Seven 69 kV lines transmit power from Flagg Pond substation to ten distribution substations. Transformation at these substations stepdown the 69 kV sub-transmission to the 13.8 kV and 4.16 kV distribution systems. A few 13.8 kV distribution circuits also serve quasi sub-transmission functions as alternate feeds between substations, and as supplies to three other distribution substations with their own 13.8 kV distribution systems.

Four National Grid 115 kV transmission lines terminate at the Flagg Pond 115 kV ring bus. Two of these lines operate in parallel from Pratt's Junction substation in Massachusetts. The other two lines terminate at Bellow's Falls substation in Vermont. However, one of these lines loops in and out of Eversource Energy's Fitzwilliam substation in New Hampshire prior to Bellow's Falls. Both pairs of lines are double-circuited on common towers.

As part of the regional New England bulk power system, the Flagg Pond 115 kV bus and these National Grid transmission lines are New England Power Pool (NEPOOL) classified Pool Transmission Facilities (PTF). PTF facilities are operated by the Independent System Operator of New England (ISO-NE), which is responsible for maintaining the integrity of the New England power system.

The electric system reached a peak load for the summer of 2022 of 95.050 MW on August 8th at 7:00 PM.

Unitil's Massachusetts service territory has a high proportion of low income households, and a high concentration of EJ populations. In particular, the Massachusetts Executive Office of Environmental Affairs has designated 90.9 percent of the Block Groups within the City of Fitchburg as EJ communities, and approximately 86.3 percent of the total population within the City reside within an EJ Block.[1] Approximately 65.0 percent of Unitil's Massachusetts customers are located within the City of Fitchburg, and as such Unitil's ESMP investments will be largely concentrated in a designated EJ community.

1.4 HOW OUR CUSTOMERS WILL EXPERIENCE THE CLEAN ENERGY TRANSITION

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.

[1] https://s3.us-east-1.amazonaws.com/download.massgis.digital.mass.gov/shapefiles/census2020/EJ%202020%20updated%20municipal%20statistics%20Nov%202022.pdf

To achieve the promise of a fully modernized grid, the Company 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.

The utility grid is the foundation upon which a more advanced energy ecosystem will be built. But from a user's perspective, the critical ingredient to achieve the promise of a "Smart Grid" is 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.

Customers will experience the clean energy transition in many different ways. For example, customers will have the ability to control their own energy usage using timely data and communication from the utility; charge their electric vehicles at multiple locations (i.e. home, work, store, etc.); interconnect distributed energy resources to the electric system; and have the options to heat their homes using heat pumps. Customers will also have the opportunity to enter into demand response programs and modify their electric usage behaviors and receive a benefit from time-varying rates.

1.5 DEMAND ASSESSMENT AND INVESTMENT DRIVERS

The Company has provided two different forecasts. One forecast is based upon a regression trendline and assumes a certain statistical confidence interval based upon historical loading and weather influences. This forecast is used in the near term to identify when system growth is likely to cause system supplies and main elements of the 115 kV, 69 kV and 13.8 kV sub-transmission and substation systems to reach unacceptable design limits, and to provide recommendations for the most cost-effective system improvements. The study examines the electric system under summer peak load conditions in its normal operating configuration and in response to design contingencies for the loss of key system elements.

The second forecast is a demand assessment, which is a longer range forecast. The demand assessment makes certain assumptions about the adoption rates for electric vehicles; the electrification of the heating loads; and the integration of clean energy resources and energy storage. Very little historical trending can occur for this type of transition. The speed at which the transition will occur will depend on pricing models, government subsidies, technology advancement, supply chain, individual situations (i.e. end of life heating system decisions), etc.

For the purposes of our analysis, the forecast is used to determine when a system improvement is likely to be required and the demand assessment is used to adequately size the system improvement to ensure the system improvement can address the speed at which the transition may happen.

The figures below show the 2025-2034 forecast and 2035-2050 demand assessment.

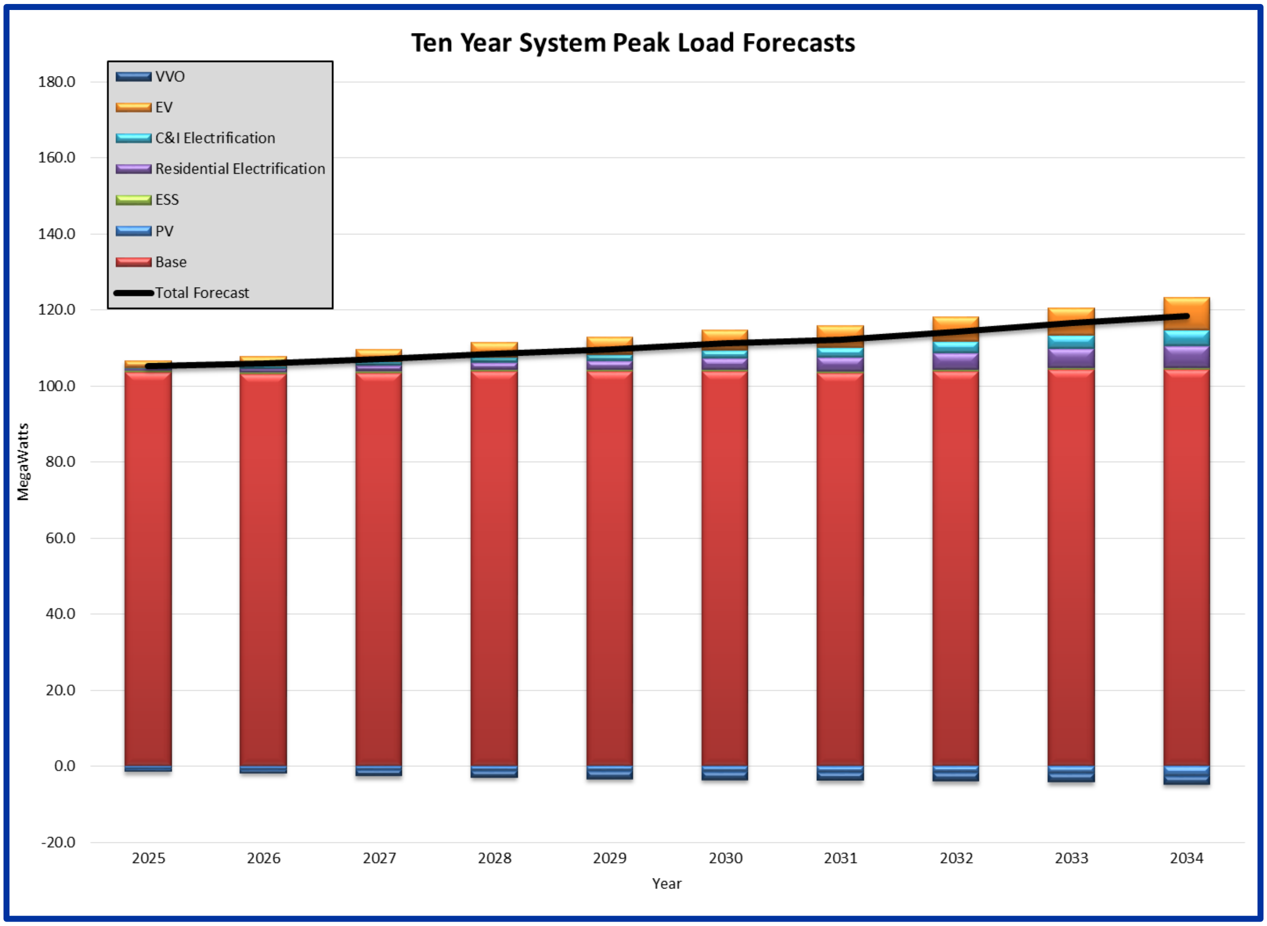

Figure 2 – Ten Year System Peak Load Forecast

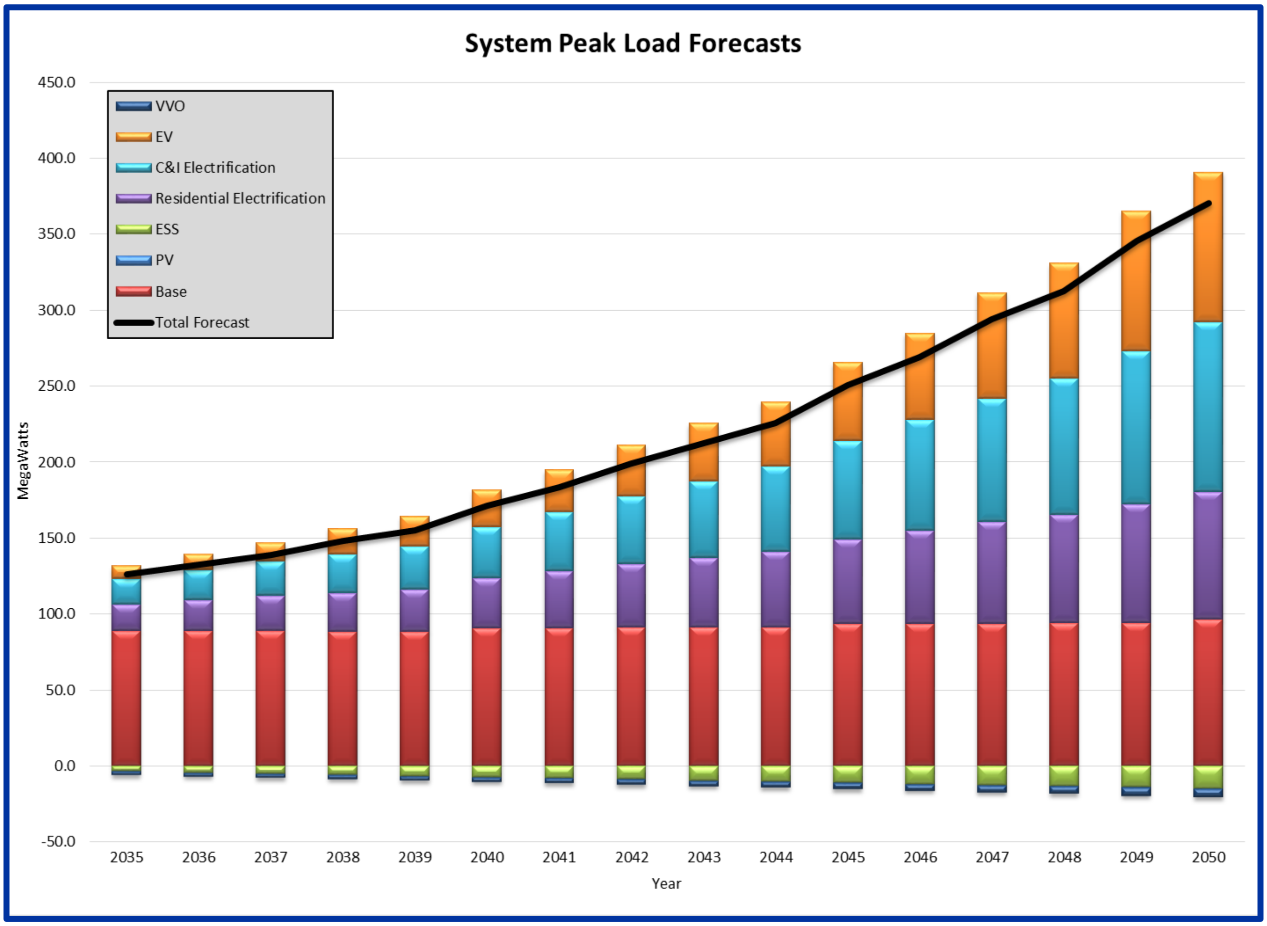

Figure 3 – 2035 - 2505 Demand Assessment

1.6 STAKEHOLDER ENGAGEMENT AND FEEDBACK

An effective stakeholder engagement process ensures that customers, municipalities, and other stakeholders understand the ESMP and will support a just transition to cleaner energy future. The Electric Distribution Companies ("EDCs") worked collaboratively to develop a consistent stakeholder engagement process. The process is designed to gain insight from stakeholders representing various customers, state agencies, community-based organizations, and industry segments in an effort to improve the ESMPs and address the comments of those stakeholders.

The success of stakeholder outreach begins with building a basic understanding of the ESMP. Stakeholder groups will need a foundational understanding of the electric system, the need for electric sector modernization plans and the Commonwealth's net zero plan goals. Building on the shared understanding, stakeholders will be presented with the insights and initiatives required to deliver the next generation grid and clean energy transition, and how they are relevant to each stakeholder group. Stakeholder engagement will be tailored to support local ESMP projects to elicit feedback and identify community concerns and needs and educate the communities about the need for upgrades being made to the electric system and the outcomes and benefits the upgrades will deliver.

1.7 5-YEAR ELECTRIC SECTOR MODERNIZATION PLAN INVESTMENT SUMMARY AND OUTCOMES ACHIEVED

The Company has taken a practical approach to the 5- and 10-year spending plans associated with this ESMP. This Plan has been developed based upon the Company's relative size and customer demographics. The Company will continue to review and improve on this Plan.

The table below provides a comprehensive view of the capital spending plan including the Company's existing capital spending plan, pre-authorized programs (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending (i.e. capacity projects, extended grid modernization, reliability and resiliency and customer facing programs). This spending plan contemplates a pre-authorization by the Department similar to the approach taken in Grid Modernization.

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
Existing and Approved Spending						
Annual Blankets	$ 5,522	$ 5,924	$ 6,695	$ 6,896	$ 7,103	**$ 32,139**
Distribution	$ 1,760	$ 3,771	$ 5,324	$ 5,686	$ 5,856	**$ 24,527**
Substation	$ 3,587	$ 3,811	$ 655	$ 675	$ 695	**$ 9,424**
Grid Modernization	$ 3,608	$ 0	$ 0	$ 0	$ 0	**$ 3,608**
EV Charging and Make Ready	$ 196	$ 196	$ 196	$ 0	$ 0	**$ 588**
Reliability/Resiliency	$1,000	$1,000	$1,100	$1,133	$1,167	**$5,400**
Other	$ 2,019	$ 2,021	$ 1,922	$ 1,980	$ 2,040	**$ 9,982**
Total Existing/Approved	**$17,922**	**$16,723**	**$15,893**	**$16,370**	**$16,861**	**$85,668**
Proposed New Spending						
Enable Grid Services	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
ADMS/DERMS	$ 0	$ 150	$ 75	$ 0	$ 0	**$225**
VVO	$ 0	$4,574	$2,875	$3,092	$2,387	**$12,928**
Automation	$ 0	$ 100	$ 100	$ 100	$ 100	**$400**
FERC Order 2222 Implementation	$ 100	$ 100	$ 0	$ 0	$ 0	**$ 200**
Cyber Security	$ 105	$ 120	$98	$98	$ 98	**$ 519**
Lunenburg Substation	$ 4,400	$ 4,700	$ 0	$ 0	$ 0	**$9,100**
South Lunenburg Substation	$ 3,000	$ 0	$ 7,000	$ 8,000	$ 2,500	**$20,500**
EV Charging and Make Ready	$ 0	$ 0	$ 0	$ 396	$ 396	**$ 792**
Targeted Reliability and Resiliency	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	**$1,000**
Total Proposed	**$8,605**	**$10,744**	**$11,148**	**$12,686**	**$6,481**	**$45,664**
Total Costs	**$26,297**	**$27,467**	**$27,040**	**$29,056**	**$23,342**	**$131,332**

Table 1 – Existing/Approved and Proposed Capital Spending ($000's)

The existing capital budget is broken down into the following categories:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. Typical blanket projects include (but are not limited to): distribution improvements, new customer additions, outdoor lighting, emergency and storm restoration, billable work, and transformer and meters purchases.

- Distribution - These projects are individually authorized projects capacity improvements or equipment replacement on the distribution system.
- Substations - These are individually-authorized projects involving capacity improvements or equipment replacement projects in substations.
- Reliability/Resiliency – These are projects designed and justified specifically to address reliability and resiliency concerns across the system.
- Others – Includes all other small categories of projects including (but not limited to): software/IT projects, communications projects, tools, laboratory, office furniture and office equipment, and improvements to the Company's buildings. In general, these facilities represent only a small portion of the overall budget.

Previously approved project spending are projects and programs that have already received approval from the Department. Those spending categories include:

- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan.
- EV Charging and Make Ready – This is the pre-approved capital spending for EV charging make ready projects.

The Company's Plan also includes proposed spending. The Company contemplates a pre-authorization of the proposed spending by the Department similar to the approach taken in Grid Modernization. The proposed projects include:

- Grid Modernization - These are new grid modernization projects proposed as part of this ESMP. These projects may be extensions or acceleration of existing grid modernization projects or programs. These project include ADMS/DERMS, VVO, Automation, FERC Order 2222 Implementation and Cyber Security.
- Capacity – The Company is proposing two substation projects during this Plan. Lunenburg Substation and South Lunenburg Substation. Both projects are designed to provide additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts.
- EV Charging and Make Ready – This is a proposed extension of the EV make ready program.

- Targeted Reliability/Resiliency – The Company is proposing to increase spending on its targeted spacer cable and undergrounding projects by a combined $1.0 million in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist.

The table below provides a comprehensive view of the operations and maintenance expense spending categorized by the existing operating expense, previously authorized spending by the Department (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending. This spending plan contemplates a pre-authorization by the Department similar to the approach taken in Grid Modernization.

The existing operating expense category includes:

- Electric Operations – Electric operations covers the operations and maintenance of the electric system including by not limited to: distribution maintenance, substation maintenance, street light maintenance, underground maintenance, metering, field services as well as the field and local supervisory labor associated with these activities.
- Professional Services – These are services the Company hires out when additional resources are needed or specialized skills are needed.
- Business Support – Business support includes the functions related to supporting the business, such as, billing, postage, insurance, customer outreach, banking fees, software fees, regulatory assessments, telecom and service company allocations.
- Customer – Customer includes functions such as, costs associated with credit and collections and the provisions for customer bad debt.
- Vegetation Management and Storms – Vegetation Management activities include the cycle pruning, hazard trees and storm resiliency program maintenance activities.

Previously approved spending includes those expenses that have been previously authorized by the Department.

- Energy Efficiency – This category represents the program administration fees associated with the Company's EE program through Mass Save.
- Electric Vehicles – Electric vehicle expense includes the Department approved customer refund and reimbursements for residential EV charging facilities.
- Grid Modernization – Grid Modernization expense includes the Department approved grid modernization expenses.

Proposed new operating expense includes proposed spending includes the following:

- Energy Efficiency – This category represents new program administration fees associated with the Company's EE program through Mass Save past the 2024 timeframe.
- Electric Vehicles – Electric vehicle expense includes proposed new expenses not previously authorized by the Department for the extension of customer refund and reimbursements for residential EV charging facilities.
- Grid Modernization – Grid Modernization expense includes proposed new grid modernization expenses not previously approved by the Department for the extension of existing as well as proposed grid modernization projects.
- ESMP Program Administration – The administration of this plan will require funding to be successful. This funding would be used for stakeholder outreach and any measurement and verification efforts (similar to grid modernization).

Project / Project Category	**2025**	**2026**	**2027**	**2028**	**2029**	**2025-2029 Total**
Existing and Approved Spending						
Electric Operations	$ 4,044	$ 4,166	$ 4,291	$ 4,420	$ 4,552	**$ 21,474**
Professional Services	$ 499	$ 514	$ 529	$ 545	$ 561	**$ 2,648**
Business Support	$ 3,751	$ 3,863	$ 3,979	$ 4,098	$ 4,221	**$ 19,912**
Customer	$ 1,602	$ 1,651	$ 1,700	$ 1,751	$ 1,804	**$ 8,508**
Vegetation Management and Storms	$ 2,529	$ 2,605	$ 2,683	$ 2,763	$ 2,846	**$ 13,427**
Energy Efficiency[2]	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	**$ 40,000**
Electric Vehicles	$ 92	$ 0	$ 0	$ 0	$ 0	**$ 92**
Grid Modernization	$ 329	$ 0	$ 0	$ 0	$ 0	**$ 329**
Proposed New Spending						
Energy Efficiency[3]	$8,000	$8,000	$8,000	$8,000	$8,000	**$40,000**
EV Charging and Make Ready	$ 0	$ 0	$ 0	$ 184	$ 184	**$ 368**
Enable Grid Services	$ 200	$ 200	$ 50	$ 50	$ 50	**$ 550**
ADMS/DERMS	$ 178	$ 188	$ 199	$ 211	$ 224	$1,000
VVO	$ 15	$ 20	$ 20	$ 20	$ 20	$ 95
FERC Order 2222 Implementation	$ 150	$ 150	$ 50	$ 50	$ 50	$ 450
Grid Mod Cyber Security	$ 20	$ 20	$ 20	$ 21	$ 22	$ 103
ESMP Program Administration	$ 75	$ 75	$ 75	$ 75	$ 75	$ 375
Total Proposed	$8,628	$8,653	$8,414	$8,611	$8,625	$42,941
Total Costs (000s)	**$29,484**	**$29,452**	**$29,596**	**$30,188**	**$30,609**	**$149,329**

Table 2 – Existing/Approved and Proposed O&M Spending ($000's)

[2] The Company is not intending to forecast EE spending as the EE plan and funding levels are adjudicated in a separate process. The table assumes the 2024 Plan spending continues at the same funding level throughout the 2025 - 2029 timeframe.

[3] The Company is not intending to forecast EE spending as the EE plan and funding levels are adjudicated in a separate process. The table below assumes the 2024 Plan spending continues at the same funding level throughout the 2025 - 2029 timeframe.

This Plan is designed to meet the expected customer outcomes of: 1) improved grid reliability, communications and resiliency; 2) enabled increased, timely adoption of renewable energy and distributed energy resources; 3) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; 4) prepare for future climate-driven impacts on the transmission and distribution systems; 5) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and 6) minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter 21N.

The Company has identified a series of eight objectives that together ensure support of a modern grid: 1) Environmentally Friendly; 2) Safety, Reliability and Resiliency; 3) Customer Enablement; 4) Security; 5) Flexibility; 6) Affordability; 7) Demand and Asset Optimization; and 8) Technical Innovation. Our objectives are crafted with guidance from the United States Department of Energy, the Department and the New Hampshire Public Utilities Commission and are used to identify the investments and technologies that best serve this new era. These objectives align with the statutory requirement as codified in G.L. c. 164, §§ 92B. The table below maps the existing and proposed projects to the objectives.

Project Or Functionality	Existing / Planned	Environmentally Friendly	Safety, Reliability, and Resiliency	Customer Enablement	Security	Flexibility	Affordability	Demand and Asset Optimization	Technical Innovation
Base Capital Budget	Existing	X	X	X	X	X	X	X	X
Enable Grid Services	Planned	X	X	X	X	X	X	X	X
ADMS/DERMS	Existing and Planned	X	X	X	X	X	X	X	X
VVO	Existing and Planned	X	X	X		X	X	X	X
SCADA Automation	Existing and Planned		X	X	X	X	X	X	X
Cyber Security	Planned		X	X	X				X
FERC 2222 implementation	Planned	X	X	X		X	X	X	X
Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
South Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
EV Charging and Make Ready	Existing and Planned	X	X	X	X	X	X	X	X
Targeted Reliability and Resiliency	Existing and Planned		X	X	X		X	X	X
Energy Efficiency	Existing and Planned	X		X	X	X	X	X	X

Table 3 – Mapping Projects to Objectives

1.8 CLIMATE IMPACTS AND BUILDING RESILIENCE

Climate change has been linked to more severe weather conditions, rising temperatures, rising sea levels, and precipitation patterns. All of these conditions can have an impact on the electric system. Climate-related risks and opportunities are reflected in the Company's strategic planning processes. Operations, and operating excellence, are critical to and driven by the Company's mission and vision, which include deliberate consideration for sustainability and climate change risk and opportunity. The Company's Mission "to safely and reliably deliver energy for life and provide our customers with affordable and sustainable energy solutions" recognizes the critical importance of our energy delivery services and also considers the lasting value sustainability creates for our stakeholders. The Company's Vision Statement, "to transform the way people meet their evolving energy needs to create a clean and sustainable future" is influenced by climate related risks and opportunities.

The resiliency of the electric system relies heavily on real-time data and next generation technology, as will our ability to communicate disruptions in service to our stakeholders. The implementation of a mobile platform to expedite damage assessment, remote monitoring and control of field devices, and a transition to next-generation smart meters and the associated infrastructure provides the ability to adapt to changing conditions, withstand potentially disruptive events, and recover rapidly from service disruptions.

The Company conducts climate change scenario planning to better understand the implications of climate change. Various climate change scenarios are evaluated to develop potential mitigation and adaptation strategies to address the most likely and most acute risks. Scenarios are derived from the Intergovernmental Panel on Climate Change, and the U.S. Global Change Research Program's Fourth National Climate Assessment[4]. This approach requires a rigorous planning process that supports strong alignment with our long-term objectives. Our strategy is built around three pillars; 1) transformative customer services and energy offering, 2) modernizing electric and natural gas infrastructure, and 3) accelerating the clean energy transition.

The Company completed a multi-day exercise to perform two separate climate scenario analyses: 1) model high emissions and climate impacts to the region (RCP 8.5)[5] and 2) forecast curbed emissions and a milder outcome (RCP 2.6).[6] Participants reviewed scenario specific supporting

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[4] https://nca2018.globalchange.gov/

[5] Representative Concentration Pathways ("RCP") 8.5 refers to the concentration of carbon that delivers global warming at an average of 8.5 watts per square meter across the planet. The RCP 8.5 pathway delivers a temperature increase of about 4.3˚C by 2100, relative to pre-industrial temperatures. RCP stands for Representative Concentration Pathways.

[6] RCP 2.6 (also referred to as RCP3-PD) is the lowest in terms of radiative forcing among the four representative concentration pathways. This particular scenario is developed by the IMAGE modeling team of the Netherlands Environmental Assessment Agency (Van Vuuren et al., 2007).

data and project operational, organizational, and financial impacts in each case. Members of the Company's Strategic Management Group were divided into groups with balanced cross functional expertise and tasked with targeting specific focus areas with the purpose of making suggestions on both risk mitigation and the pursuit of opportunities. Results were compiled, ranked by intensity across a risk mitigation 'heat map,' and reviewed to establish common themes, priorities, and alignment to the strategic pillars contained within the Company's existing strategic planning documents.

The results of the climate-related scenario analysis represent an understanding of which physical and transitional risks under which RCPs are material to the Company, and which of these risk areas have the highest risk prioritization. Seven physical risks and four transitional risks for two RCP scenarios (11 total cases) were identified for company specific assessment.

The assessment included identifying the likelihood and impact to the Company as well as the risks, mitigating actions, and opportunities associated with each. Of those 22 cases, six were identified as posing the highest likelihood and impact to the Company. These were Technology; and Policy, Legal, and Regulatory under RCP 2.6 and Temperature Extremes; Hurricanes and Storms; Reputation; and Change in Mean Temperature under RCP 8.5. For each of the six cases, the identified risks, mitigating actions, and opportunities faced were reviewed for inclusion in current strategic planning initiatives. Each of these areas were reviewed for additional data and input need and are incorporated into an internal strategic planning project management plan to continue analysis and further inform strategic planning.

1.9 WORKFORCE AND SOCIETAL BENEFITS OF A JUST TRANSITION

The Company's service territory has a high percentage of customers who live in an environmental justice community or are identified as a low-to-moderate income household. The Company is keenly aware that the future of the electric system, if not implemented in a carefully thought out plan, can have a diverse impact on our customers and the communities we serve. Mitigating the potential adverse effects of a clean energy transition on our customers and communities and promotes the benefits and opportunities the transition can bring to our customers and communities. A just transition to a clean energy future will ensure the benefits of the clean energy transition are shared widely and support provided to those who stand to lose from the transition.

From a workforce standpoint, technology is rapidly evolving. This growth will result in increased technical and non-technical jobs and open up opportunity for training and growth within the workforce. These jobs are local to our service territories so residents within our communities will have a greater opportunity for employment. We are focused on providing the skills and knowledge needed to develop and train a workforce that supports the transition to a modern grid while returning economic benefits to the communities that we serve.

1.10 CONCLUSION AND NEXT STEPS

Unitil appreciates this opportunity to present its ESMP. The Plan is designed to detail the Company's plan to proactively upgrade its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the commonwealth realize its greenhouse gas emission limits. The Company looks forward to working with the stakeholders in the review of the Plan.

2 COMPLIANCE WITH THE EDC REQUIREMENTS OUTLINED IN THE 2022 CLIMATE ACT

This Plan provides a transparent planning process to help the Commonwealth realize its GHG limits as articulated in Section 53 of Chapter 179 of the Acts of 2022 (An Act Driving Clean Energy and Offshore Wind; the "2022 Climate Act"), as codified in G.L. c. 164, §§ 92B and 92C.

In accordance with G.L. c. 164, § 92B(a), the Plan has been developed to proactively upgrade the distribution system (and, where applicable, the associated transmission system) to: (i) improve grid reliability, communications and resiliency (Sections 4 and 10 on reliability and resiliency and Section 6.3 on communications); (ii) enable increased, timely adoption of renewable energy and distributed energy resources (Sections 6 and 7); (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy (Sections 7, 8, and 9); (iv) prepare for future climate-driven impacts on the transmission and distribution systems (Section 10); (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, the transmission system (Sections 6, 8, and 9); and (vi) minimize or mitigate impacts on the ratepayers of the Commonwealth, thereby helping the Commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter 21N (Sections 7 and 9).

The Plan proposes investments and alternative approaches that improve the electric distribution system in a manner designed to achieve the statutory objectives described above while maintaining reliable and resilient performance. The proposed investments and alternatives include traditional utility upgrades, in addition to electrification and integration of DERs.

The Company's ESMP describes in detail each of the following elements, as required by G.L. c. 164, § 92B(b): (i) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks (Sections 4 and 10); (ii) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable (Sections 6 and 9); (iii) patterns and forecasts of distributed energy resource adoption in the Company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies (Section 5 and 8); (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources (Section 9); (v) improvements to the distribution system that will facilitate transportation or building electrification (Sections 7, 8, 9,); (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N (Sections 7 and 9); (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment (Sections 4, 5, 9); (viii) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response (Sections 7, 9); and (ix) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments (Sections 7 and 9).

Additionally, the Company's ESMP identifies customer benefits associated with the investments and alternative approaches including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of distributed energy resources, avoided renewable energy curtailment, reduced greenhouse gas emissions and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the commonwealth (Sections 6, 7, 12). G.L. c. 164, § 92B(b).

The Company prepared its plan using three planning horizons for electric demand: a 5-year forecast (Section 5); a 10-year forecast (Section 5); and a demand assessment through 2050 to account for future trends, including, but not limited to, future trends in the adoption of renewable energy, distributed energy resources and energy storage and electrification technologies necessary to achieve the statewide greenhouse gas emission limits and sublimits under chapter 21N (Section 8.0). G.L. c. 164, § 92B(c)(i). The Plan also includes a summary of all proposed and related investments (Section 7), alternatives to these investments and alternative approaches to financing these investments (Section 7) that have been reviewed, are under consideration or have been approved by the department previously. G.L. c. 164, § 92B(c)(ii).

Finally, the Company has submitted this plan and solicited input, such as planning scenarios and modeling, from the Grid Modernization Advisory Council established in section 92C, responded to information and document requests from said council and is committed to conducting technical conferences and a minimum of 2 stakeholder meetings to inform the public, appropriate state and federal agencies and companies engaged in the development and installation of distributed generation, energy storage, vehicle electrification systems and building electrification systems (Section 3). G.L. c. 164, § 92B(c)(iii).

3 STAKEHOLDER ENGAGEMENT

An effective stakeholder engagement process ensures that customers, municipalities, and other stakeholders understand the ESMP and its role in ensuring the transition to a cleaner energy future. The EDCs agree on the importance of conducting comprehensive outreach by engaging a cross-section of customers, communities, Environmental Justice ("EJ") stakeholders, low-income and moderate-income customers, municipalities, small and medium businesses, state agencies, community-based organizations, and industry collaborators

Stakeholder groups will need a foundational understanding of the electric system, the need for electric sector modernization plans and the Commonwealth's net zero goals. Building on this shared understanding, stakeholders will be further educated on the insights and initiatives required to deliver the next generation grid and clean energy transition. Stakeholder engagement will be tailored to support local, significant ESMP infrastructure projects to elicit feedback and identify community concerns and needs and educate the communities about the need for upgrades being made to the electric system and the outcomes and benefits the upgrades will deliver. Community concerns will be taken into consideration in the overall siting and design of these types of local ESMP projects.

3.1 CUSTOMER OUTREACH

Unitil believes it is important to engage with customers and municipalities in a meaningful manner so that they understand the grid needs and proposed infrastructure projects, while the Company will seek to understand the impact the projects may have on the customers and municipalities and solicit feedback.

The Company supports the concept proposed by the EDCs to develop a Community Engagement Stakeholder Advisory Group. As explained below, the goal of the new advisory group is to develop a Community Engagement Framework that can be applied to certain infrastructure projects (i.e. substation projects) before they are brought before the EFSB. Unitil believes that the Advisory Group and Framework should consider the unique characteristics of each EDC. The composition of the advisory group will be informed by the GMAC, utilities and any comments to the initial filing of the ESMP with GMAC.

Unitil intends to conduct at least two stakeholder meetings in the fall to educate stakeholders and gain feedback on the ESMP. The Company is also considering targeted workshops, regional in-person events, media briefings and one-on-one meetings with municipalities/communities that have identified infrastructure investment plans in the first five years of the plan. Additional outreach will be determined based on a case-by-case basis. Moreover, Unitil recognizes that sharing information in a widely-accessible format is important to ensure transparency. The Company will develop an ESMP webpage on its website, detailing an overview of the ESMP, the draft and final ESMP reports, stakeholder workshop information and meeting materials, and links to the GMAC website.

3.2 MUNICIPAL OUTREACH

Municipal outreach is most important when projects or investments will be located within or impact the municipality. It is important to provide the municipality with the knowledge and information required to fully understand the need for the project as well as the scope and impact of the project. Outreach may include targeted workshops, regional in-person events, media briefings, and one-on-one meetings with municipalities/communities that have identified infrastructure investment plans in the first five years of the Plan.

3.3 EJC OUTREACH

A significant portion of Unitil's service territory is designated as an environmental justice community, and thus it is critical that these customers understand and receive the benefits available through the ESMP and a modern distribution system, as well as have the opportunity to provide feedback on significant distribution infrastructure projects located within the community. Outreach specific to environmental justice communities will consider factors essential to ensuring that the communication is effective, including notice, location and accessibility (with consideration given to in-person and virtual participation), and scheduling in a manner that encourages participation, language and translation needs. The Company recognizes that further logistical arrangements may need to be made in order to encourage participation and promote accessibility of these materials, specifically in EJCs. The Company will collaborate with community groups to receive feedback on what arrangements may be helpful for customers and will seek to accommodate these requests when feasible.

3.4 STAKEHOLDER MEETINGS AND INFORMATION EXCHANGE (INCL. TWO TECHNICAL SESSIONS)

The Company will hold at least two stakeholder meetings to educate stakeholders and gain feedback on the ESMP. The participants for the stakeholder group are designed to cover a broad cross-section of the groups who may be impacted by the ESMP. The participants selected for the stakeholder group will be: 1) members of the GMAC; 2) community and equity-focused groups, business organizations, academic institutions and municipalities; 3) companies engaged in the development of: Distributed Generation ("DG"), energy storage, Electric Vehicle ("EV") systems, and building electrification systems. The stakeholder workshops will be facilitated by a common moderator for all EDCs, due to the consistent nature of all three plans. The sessions will be noticed in advance and hosted at times recommended by the community groups, at easily accessible locations. Language translation services will be provided where appropriate. All recommendations and responses will be documented to ensure transparency.

The concept of stakeholder meetings was presented and at the July and August GMAC meetings during the drafting of the ESMP. The EDCs are currently reaching out to potential facilitators/moderators to manage the two stakeholder sessions.

3.5 STAKEHOLDER INPUT AND TRACKING – INCLUDING EXPLANATION OF STAKEHOLDER INPUT NOT INCORPORATED

Following the filing of the ESMPs, the Company will solicit feedback from the GMAC and set a date, time and location for the stakeholder workshops. The Company will gather input from the workshops and track all recommendations. The Company will consider all recommendations and incorporate into the final report to the Department where applicable.

3.6 KEY TAKEAWAYS FROM STAKEHOLDER ENGAGEMENT

The Company will gather input from the stakeholder workshops and track all recommendations. The Company will provide responses to all recommendations and incorporate into subsequent plans where applicable.

3.7 FUTURE STAKEHOLDER/COMMUNITY ENGAGEMENT PROCESS (FORECASTING, SOLUTION ALTERNATIVES, COMMUNITY IMPACTS)

The goal of the stakeholder engagement process is to have a transparent and open process that is easy to follow, easy to understand and easy to provide comment and consideration to future projects and future modernization plans. The Company will continue to identify improvements and best practices learned from our stakeholder outreach as well as the stakeholder outreach efforts of the other EDCs.

3.8 ONGOING AND NEW PROPOSED STAKEHOLDER WORKING GROUPS

Ongoing ESMP Fall Workshops

Unitil and the other EDCs are committed to hosting two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. These workshops are critical to ensuring there is stakeholder engagement and feedback gathered. These workshops will be conducted in the following manner:

- Stakeholder attendees will be pre-determined in consultation with the GMAC.
- Professionally facilitated.
- Workshops will be hosted virtually, at times recommended by the GMAC, with language translation services
- Use as an opportunity to educate stakeholders and gain feedback from the voices of the community.

- The EDCs will track all recommendations and develop a formalized feedback loop for increased transparency
- All recommendations will be shared with the GMAC.

Proposed "Community Engagement Stakeholder Advisory Group"

Unitil supports the development of a new Community Engagement Stakeholder Advisory Group ("CESAG"). The CESAG will allow for a structured opportunity for the EDCs to develop a comprehensive stakeholder engagement and community benefits agreement framework that will enable a) increased transparency and stakeholder understanding of the complex electrical grid and EDC distribution planning process through establishment of a repeatable community engagement platform and b) ensure communities that host new bulk substations and associated transmission infrastructure directly benefit from this clean energy enablement infrastructure. The CESAG will help to ensure that historic obstacles to stakeholder engagement such as language barriers or the location/time of engagement sessions are addressed to ensure the widest possible level of community participation.

Members and Meeting Frequency:

- Composition of the CESAG members would be agreed upon by members of the GMAC but would be led by the EDCs, and would include a set number of GMAC members, and Community Based Organizations.
- CESAG by-laws will be developed by the EDCs with input from the GMAC
- CESAG would begin meeting in February 2024 and meet two times per month for 4 months to develop the Community Engagement Framework and finalized by end of Q2 2024.
- Frequency of future meetings would be determined by the CESAG as applicable.
- Meetings will be professionally facilitated

Community Engagement Framework

To meet the objectives of the Commonwealth laid out in An Act Driving Clean Energy and Offshore Wind, it will be critical to build new distribution infrastructure to accommodate higher penetrations of clean energy and electrification. This new infrastructure needs to be built relatively quickly in order to meet the Commonwealth's overall decarbonization goals and the near-term interim Clean Energy and Climate Plan emissions reduction targets. Given the need to execute all ESMP projects, the first mandate of the proposed CESAG would be to develop a *Community Engagement Framework* that can be used by the EDCs as an overall guide to working with all potential impacted communities and stakeholders prior to projects going before the Energy Facilities Siting Board. This framework will be co-developed and informed by a partnership between the EDCs and key community-based organizations, and should take into account the specific characteristics of each EDC.. The EDCs are, fundamentally, providers of safe and reliable energy. As each continues to build and enhance our community engagement efforts, it is important the EDCs remain informed by the voices of their communities. The best path towards successful and clear community engagement is to have a framework co-developed by those stakeholders that live in and engage with communities on a daily basis.

The EDC community engagement framework would enable the following:

- Guide the EDCs on best ways to inform and educate communities about the electrical distribution system
- Identify opportunities to support organizations that could help to further cultivate good will and community engagement and/or participation.
- How input should be solicited and responded to
- Principles for EDC outreach and equitable engagement efforts during project development including recommendations around producing non-technical abstracts about proposed projects that can be disseminated to community members and other ways to provide critical information about the impacts and benefits of projects to the public.
- Define key stakeholders, by categories and specific organizations in specific regions of the Commonwealth.

The goal is for the EDCs to follow a framework co-developed with community partners to allow for greater community understanding and support around new infrastructure projects. This will help expedite critical projects necessary as part of the ESMP to accelerate decarbonization in the Commonwealth. As the EDCs continue to learn and grow in this space, the CESAG can continue to identify ways the EDCs can adjust outreach and engagement strategies in response to feedback from partners, allies and communities.

4 CURRENT STATE OF THE DISTRIBUTION SYSTEM

This section describes the current state of the Company's electric distribution system. The section begins with a description of the distribution system including customer demographics, and economic development. The section continues by describing DER adoption, grid services, and capacity deficiency, age of distribution and substation infrastructure, provides information on the reliability and resilience of the distribution system. The section ends by describing the siting and permitting process.

4.1 STATE OF THE DISTRIBUTION SYSTEM AND CHALLENGES TO ADDRESS

4.1.1 The Electric Grid – An Overview

The electric grid generally consists of the transmission system, sub-transmission system, and the distribution system. These systems are connected to each other through substations. The transmission system consists of a grid of high voltage lines that interconnects and transfers high amounts of power across many states. No customers are served directly from the transmission system. Traditionally the large generating stations providing power to the region are connected directly to the transmission system. The transmission grid is designed and planned such that a loss of an element does not affect the electric customers. The transmission system is regulated by the Federal Energy Regulatory Commission (FERC) and is planned and operated by an area independent transmission operator. The planning and operation of the transmission system includes planning outages of transmission facilities and dispatching the generating facilities connected to the transmission lines and those enter into the power market. The transmission operator for New England is ISO-NE. The transmission lines typically operate at 115 kilovolts (kV) and higher.

The sub-transmission system conducts electricity between the major transmission system to regional distribution substations. Sub-transmission systems are operated by the regional electric company and typically operate at 34.5 kV to 69 kV.

Substations are the points of the electric grid where transmission lines and sub-transmission lines are connected to distribution feeders. The systems are connected at the substations through large circuit breakers, switches, power transformers, voltage regulating equipment, and automatic protection control equipment. The circuit breakers operate to energize and de-energize lines and are controlled by the automatic protection schemes to protect the transmission lines and substation equipment from failure. The power transformers lower the voltage from the transmission high voltage to a lower operating voltage of the distribution system.

The distribution system originates at substations supplied from the transmission or sub-transmission system and is operated at medium voltages (typically 34.5 kV and below), and consists of distribution feeders (circuits), poles, transformers, protection devices, voltage regulators and other equipment to supply reliable electric service to the end customer within required voltage levels. The protection devices (circuit breakers, reclosers, fuses, etc.) automatically open to de-energize circuits or sections of circuits to isolate as few customers due to short circuit (fault) on the system. Typically, when the protection devices open, all the customers down-line from that device are out of power. Although there may be protective devices or switches interconnecting one distribution circuit to another, unlike the transmission system, typically the distribution system is designed with power flowing in one direction from the substation to the customer. Therefore, when there is a fault on the distribution system, the power flow to the customer is interrupted, until the system can be reconfigured and repairs to the faulted area can be made.

The Figure below displays the elements and power flow of a traditional electric system.

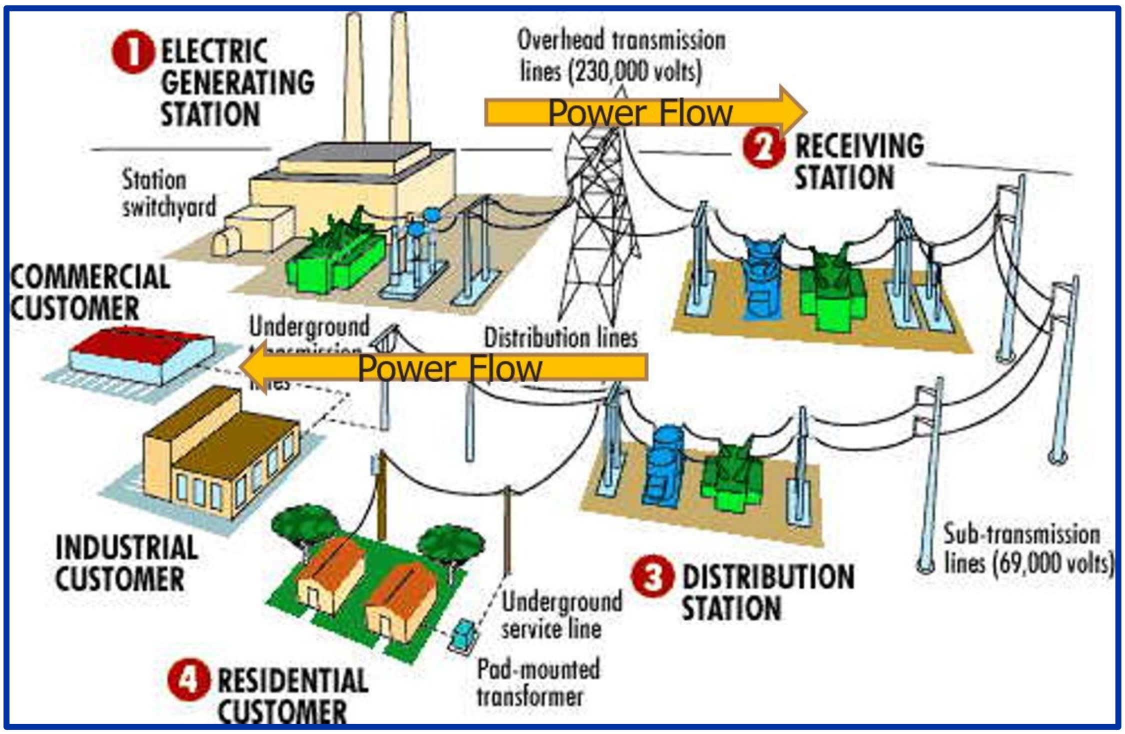

Figure 4 – Traditional Electric System (source Energy Council of the North East)

In traditional electric systems, the electricity flowed in one direction. Large electric generating plants are connected to the high voltage lines of the transmission system. The electric power flows from the transmission system, through the substations, to the electric customers connected to the distribution system. In this configuration, the distribution system is dependent on the transmission system, and the transmission system is rarely affected by events on the distribution system.

Presently the distribution system is transforming such that, with concentrated installation of DER on the distribution system, the power flow is bi-directional within in the distribution system and the amount of solar generation on the distribution system affects the dispatching of large synchronous generators on the transmission system.

Unitil's electric power system is presently supplied from the National Grid's115 kV transmission system. Service is taken from National Grid at a 115 kV to 69 kV transmission substation owned and operated by Unitil. The transmission substation consists of a 115 kV high side ring bus, two 115 to 69 kV autotransformers, and a 69 kV low side ring bus.

Within the Unitil electric system, there are seven 69 kV (sub)transmission lines interconnecting the transmission substation with ten distribution substations. Transformation at these substations stepdown the 69 kV (sub)transmission to the 13.8 kV and 4.16 kV distribution systems. A few 13.8 kV distribution circuits also serve quasi sub-transmission functions as they are alternate feeds between substations, and supplies to other distribution substations with their own 13.8 kV distribution systems.

The figure below displays the approximate location of the Unitil substations.

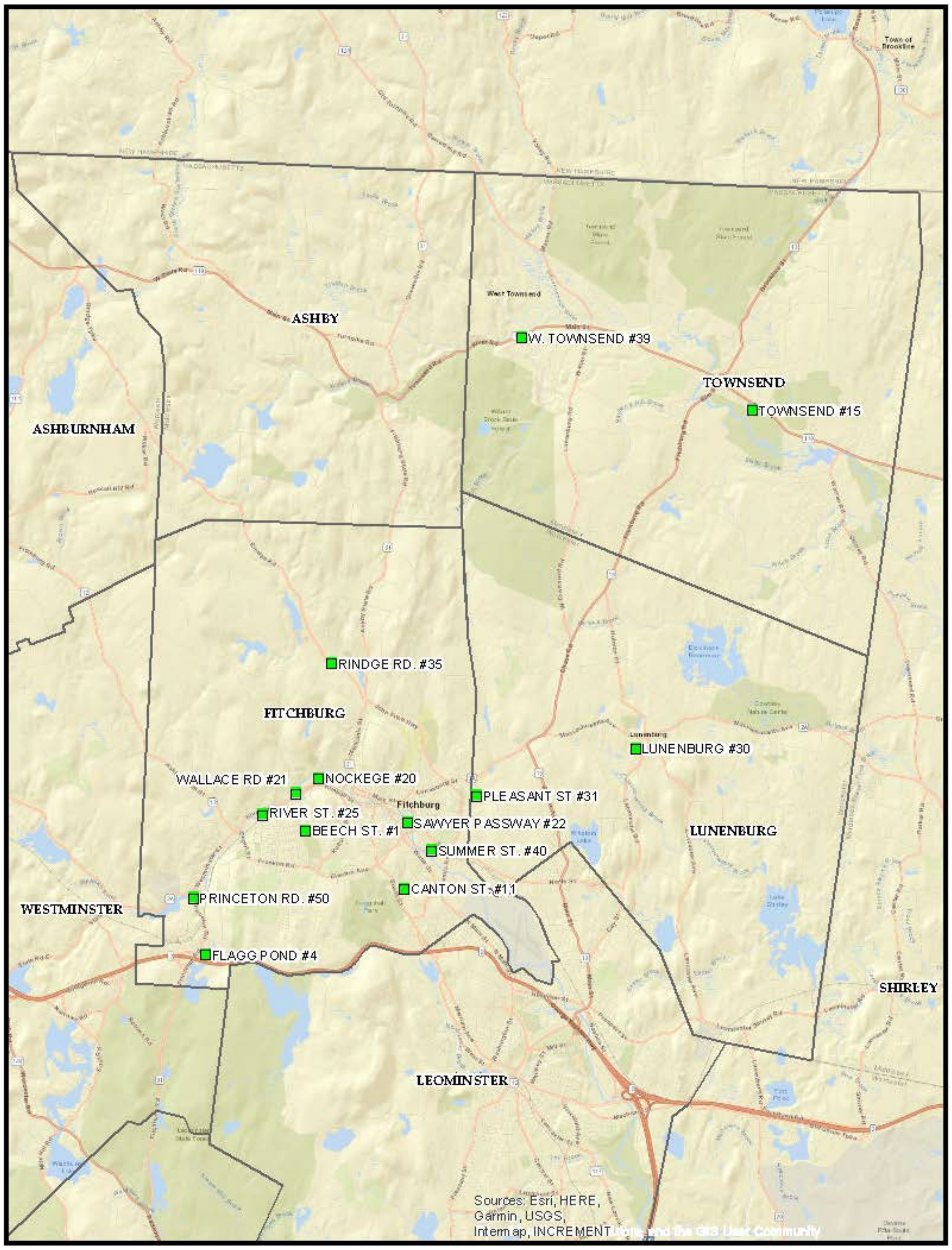

Figure 5 - Unitil Substation Location Map

As noted above, the power flow is bi-directional within in the distribution system and even from the distribution system through the bulk substations to the transmission system. The transmission system is more affected by power flows and events on the distribution system. At light load times in the past, the solar generation has supplied more than the total demand on the electric system and has reversed the power flows at the transmission interchange such that power flowed from the 13.8kV distribution system, through the 69 kV sub-transmission system onto the 115 kV New England transmission system.

4.1.2 Customer demographics

The Company serves approximately 30,000 customers in the towns of Ashby, Fitchburg, Lunenburg and Townsend, and individual services in Leominster, Shirley, and Westminster. Approximately 85 percent of the customers are residential. The table below details the number of customer accounts broken down by rate class.

Customer Rate Class	Count	Description	% of Total Accounts
R-1	19,832	Residential	65.7%
R-2	5,025	Residential Assistance	16.6%
R-3	1,012	Residential Heat	3.4%
R-4	238	Residential Heat -Assistance	0.8%
G-1	2,511	Small Commercial/Industrial	8.3%
G-2	1,551	Medium Commercial/Industrial	5.1%
G-3	29	Large Commercial/Industrial	0.1%
Special Contracts	2		
Total	30,200		

Table 4 – Customer Count by Rate Class

Based upon the Massachusetts Census Data from 2020[7] the city of Fitchburg has a population of 41,946, while the towns of Lunenburg, Townsend and Ashby have populations of 11,782, 9,127 and 3,193 respectively. The total population of the four cities and towns with the Company's electric service territory is 65,598 or 0.9% of the Massachusetts population of 7,029,917.

[7] Massachusetts Census Data (malegislature.gov)
https://malegislature.gov/Redistricting/MassachusettsCensusData/CityTown

Environmental Justice Communities:

In Massachusetts, beginning in June 2021, a neighborhood (i.e., a census block group) is defined as an Environmental Justice community if any of the following are true: (1) the annual median household income is equal to or less than 65 percent of the statewide median ($81,468 for a household of four in 2021), (2) minorities compromise 40 percent or more of the population, (3) 25 percent or more of households lack English language proficiency (English isolated), or (4) minorities compromise 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income.

According to the last census 71.9 percent of Block Groups in Fitchburg are environmental justice communities. Also, 61.2 percent of the Fitchburg population are in environmental justice Block Groups. The figure below displays a map of the environmental Justice communities in the Unitil territory.

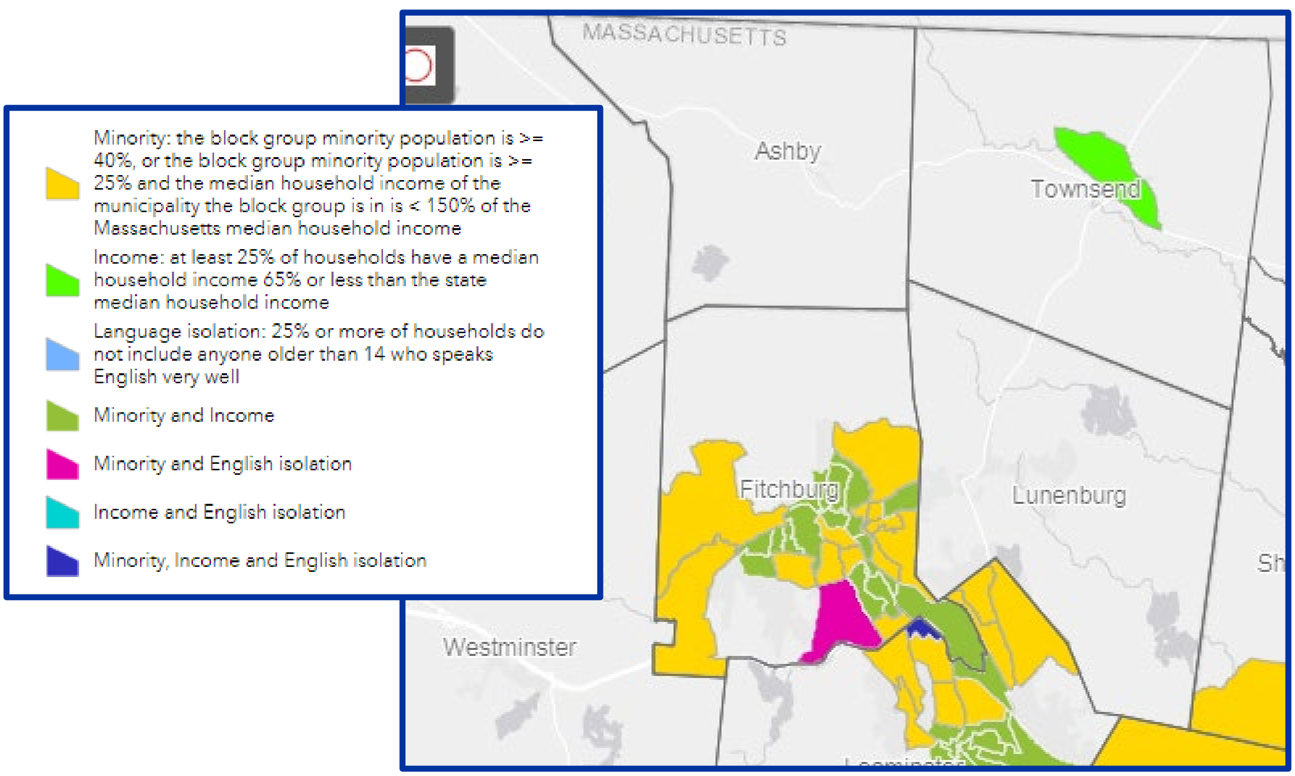

Figure 6 – Massachusetts 2020 Environnmentla Justice Populations

4.1.3 Economic Development

The labor statistics for the Leominster-Gardener-Fitchburg area show that the labor rates have not fully recovered since prior to the COVID-19 pandemic in 2020. The number of people in the labor force were steadily increasing prior to 2020, and in 2022 the number was lower than the labor rate of 2017. The 2022 unemployment rate was equal to the rate in 2017. The table below shows the labor statistics of the area from the U.S. Bureau of Labor.

	Labor Force		Employment		Unemployment		Unemployment Rate	
Year	**Number**	**Change**	**Employed**	**Change**	**Unemployed**	**Change**	**Rate**	**Change**
2013	75,275		69,113		6,162		8.20	
2014	76,271	1.3%	71,006	2.7%	5,265	-14.6%	6.90	-15.9%
2015	76,323	0.1%	71,937	1.3%	4,386	-16.7%	5.70	-17.4%
2016	76,935	0.8%	73,249	1.8%	3,686	-16.0%	4.80	-15.8%
2017	79,490	3.3%	75,969	3.7%	3,521	-4.5%	4.40	-8.3%
2018	81,821	2.9%	78,540	3.4%	3,281	-6.8%	4.00	-9.1%
2019	81,251	-0.7%	78,346	-0.2%	2,905	-11.5%	3.60	-10.0%
2020	79,807	-1.8%	71,519	-8.7%	8,288	185.3%	10.40	188.9%
2021	79,196	-0.8%	74,153	3.7%	5,043	-39.2%	6.40	-38.5%
2022	78,593	-0.8%	75,167	1.4%	3,426	-32.1%	4.40	-31.3%

Table 5 – Labor Statistics Fitchburg-Leominster-Gardener Area

4.1.4 Electrification Growth

The Company's EV charging and make ready program was approved by the Department in December 2022. The program is designed to support the growth of electric vehicles in Massachusetts by providing incentives to public and residential charging. There are approximately 300 electric vehicles registered within the service territory.

The Company, through the MassSave EE Plan, provides incentives to customers to install heat pumps. There are approximately 1000 heat pumps installed in the service territory. Most of the systems being installed at this point are hybrid heating systems.

4.1.5 DER Adoption

Although Unitil customers account for approximately 0.85% of the electric power sales in Massachusetts, about 1.6% of the total solar generation in the Commonwealth is provided by systems connected onto the Unitil distribution system. Approximately 12% of the all Unitil electric customers have DER in service or approved to install at their residence or facility. For short durations, during times of light load during the day, Unitil has experienced a small amount of reverse power flow from the distribution system through the 69kV sub-transmission system to the ISO-NE operated 115kV transmission lines.

The Chart below displays the aggregate amount of DER that has been interconnected on the Unitil electric system in the past ten years. The total amount is approximately 70% of the historical peak load.

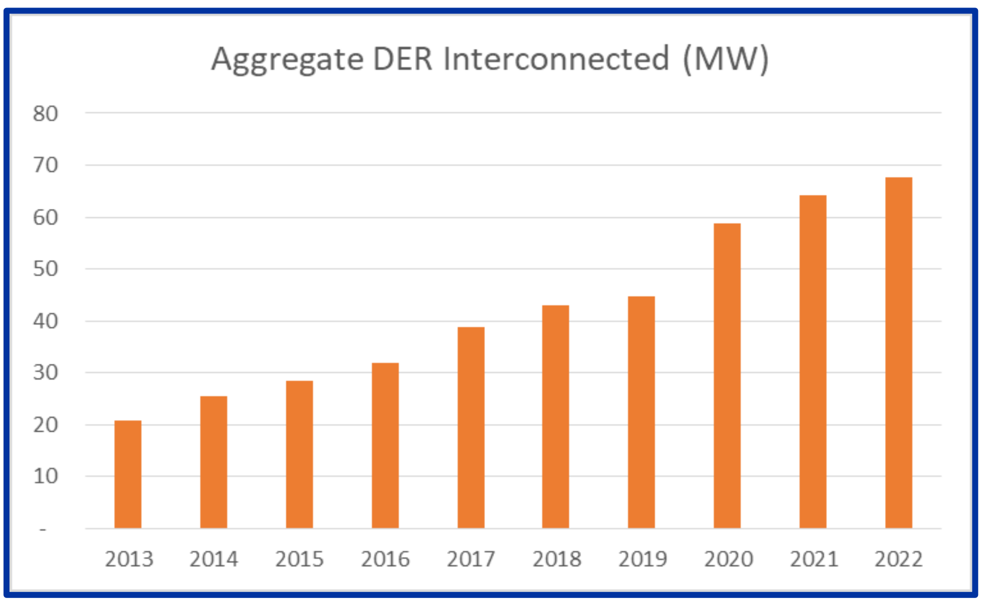

Figure 7 – Aggregate Interconnected DER Capacity

The table below lists the number of DERs interconnected on the Unitil electric system listed by type of DER.[8]

[8] Data taken from Appendix 1 of the Company's 2022 Grid Modernization Annual Report.

Type of DER	No. of Facilities	Nameplate Capacity (MW)
Solar	2,723	43.7
Solar + Storage	36	1.2
Gas	7	0.4
Storage	3	2.0
Wood	1	18.0

Table 6 – DER Connected to Electric System

The table below shows the DER hosting capacity of each distribution substation on the Unitil system. The Hosting Capacity is the amount of net capacity the transformer has to allow generation to flow in the reverse direction. This analysis compares 30% of the peak load to the aggregate DER capacity.

Substation	Total Installed Generation (kVA)	DER Hosting Capacity (kVA)
Beech Street	10,057	15,200
Canton Street 13.8 kV	1,343	13,900
Canton Street 4 kV	625	2,969
Lunenburg	11,284	2,300
Pleasant Street	13,838	3,000
Princeton Road	8,080	14,700
River Street	11,018	4,000
Sawyer Passway	5,571	15,900
Summer Street	3,638	35,500
Townsend	4,584	8,900
West Townsend	7,314	5,600
Total System	**77,352**	**46,300**[9]

Table 7 - DER Hosting Capacity (as of 6/1/23)

[9] Total System Hosting Capacity is constrained at the 115/69 kV substation.

Power generation DER has created challenges to the operation and planning of the distribution system where, due to the aggregate of the DER, power can now flow in both directions. Planning of system capacity must now be analyzed during peak load times as well as light load and high generation times. In addition to capacity analysis, the operation of the distribution system equipment must be considered to ensure the equipment will operate correctly during reverse power flow. Specifically, protective devices and voltage regulating devices need to be set to operate correctly in both directions.

Electrical Energy Storage DER (batteries) introduces the same challenges for single installations. A battery acts as a positive load and the negative load at any given time. Without utility control or constraint of the battery, the system must be planned to have the capacity for the battery to charge at full rating (positive load), or discharge at full rating (negative load), at any time of the day. Because the transmission system having different capacity needs than the distribution system, a battery operating for transmission markets, may cause capacity constraints, in both directions, on the distribution system. For this reason, the Company does not assume a particular schedule for the operation of a battery. It plans the needed system capacity at the worst case.

4.1.6 Grid Services

The Company's demand response program is designed to reduce load at the time of system peak in an attempt to defer capital investment. There are currently 157[10] customers who participate in the Company's demand response program. The accounts for 178 kW[11] of load reduction at the time of system peak.

4.1.7 Capacity Deficiency

Currently, the Unitil system loading peaks in the summer months. In order to operate the electric system in a safe and reliable manner, it is important to ensure the loading on any piece of equipment does not exceed the rated capacity of the equipment. For that reason, Unitil calculates summer and winter thermal ratings for each type of equipment and forecasts the loading on all circuits and substations. Thermal ratings of each load-carrying element in the

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[10] In 2022, there are 154 residential and 3 commercial and industrial customers participating in the program
[11] In 2022, the residential customers saved 99kW and the commercial and industrial customers saved 79kW.

system are determined in order to obtain maximum use of the equipment. The same rating methodologies are used for sub-transmission, substation and distribution equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers, and switches).

In its planning process, each year Unitil analyzes the expected amount of load and compares it to the equipment ratings per its distribution and system planning criteria. Presently Unitil does not have any loading constraints through 2023. Future expected constraints are discussed in Section 6. The tables below list the summer rating of substation transformer and distribution circuit with the forecasted peak load for 2023.

Substation Transformer	Overall Rating Normal (kVA)	LTE (kVA)	Forecasted 2023 Peak Load (kVA)
Beech St.	25,470	26,880	14,316
Canton St. T1	14,000	14,000	4,460
Canton St. T2	4,060	4,220	2,031
Lunenburg	11,989	12,670	11,408
Pleasant St.	14,000	14,000	9,842
Princeton Rd T2	23,200	24,130	7,880
Princeton Rd T3	23,200	24,130	20,187
River St. 13.8 kV	16,240	16,890	7,436
Sawyer Passway T1	21,225	22,946	6,487
Sawyer Passway T2	21,225	22,946	6,487
Summer St.	28,683	28,683	17,366
Townsend	12,340	12,700	10,175
W. Townsend	10,756	10,756	7,578

Table 8 – Substation Transformer Loading Constraints

Distribution Circuit	Overall Rating		Forecasted 2023 Peak Load (kVA)
	Normal (kVA)	LTE (kVA)	
01W01	8,916	9,561	4,523
01W02	8,916	9,561	3,035
01W04	9,561	9,561	2,758
01W06	8,916	9,561	4,000
11W11	12,692	13,385	4,460
11H10	2,017	2,017	1,096
11H11	2,017	2,017	1,004
30W30	9,198	9,943	6,956
30W31	10,188	11,014	4,452
20W22	8,916	10,780	1,888
31W34	11,674	12,620	2,277
31W37	12,692	14,341	4,418
31W38	12,692	14,341	3,146
50W53	13,584	14,686	7,880
50W51	11,886	12,850	4,602
50W55	8,066	8,720	6,997
50W56	8,490	9,178	8,588
25W29	11,951	11,951	4,000
25W27	9,561	9,561	2,586
25W28	9,561	9,561	1,385
22W17	8,533	8,533	601
22W2	3,585	3,585	761
22W1	9,322	9,322	7,157
22W3	3,608	3,705	793
22W8	8,490	8,533	616
22W10	9,322	9,322	1,888
22W11	8,490	8,533	1,265
40W38	7,673	9,274	2,350
40W39	9,198	9,561	5,156
40W40	9,561	9,561	8,111
40W42	9,561	9,561	3,911

15W15	8,844	9,561	4,175
15W16	8,844	9,561	5,390
15W17	8,844	9,561	1,584
1341	9,728	10,517	3,137
35W36	6,282	7,328	3,113
39W18	12,692	13,768	4,177
39W19	7,641	8,261	3,401

Table 9 – Distribution Circuit Loading Constraints

4.1.8 Aging infrastructure

While upgrading portions of the distribution system for increased capacity needs is required, in order to continue to provide safe and reliable service and transition to a decarbonized future, replacement and upgrade of the existing aging infrastructure is also necessary.

4.1.8.1 Substation Equipment

The main substation equipment consists of power transformers and breakers. Because a substation is the supply to multiple distribution feeders, a failure at the substation effects many more customers than a failure on a feeder. Presently there are 78 breakers/reclosers and 15 power transformers installed in the substations.

The average age of the Protection devices (breaker and reclosers) is 23.5 years. The age of most breakers is the year the substation was constructed or a major project was implemented to upgrade the substation. The chart below displays the ages of the existing breakers and Reclosers. Char Y below displays the average age at each substation.

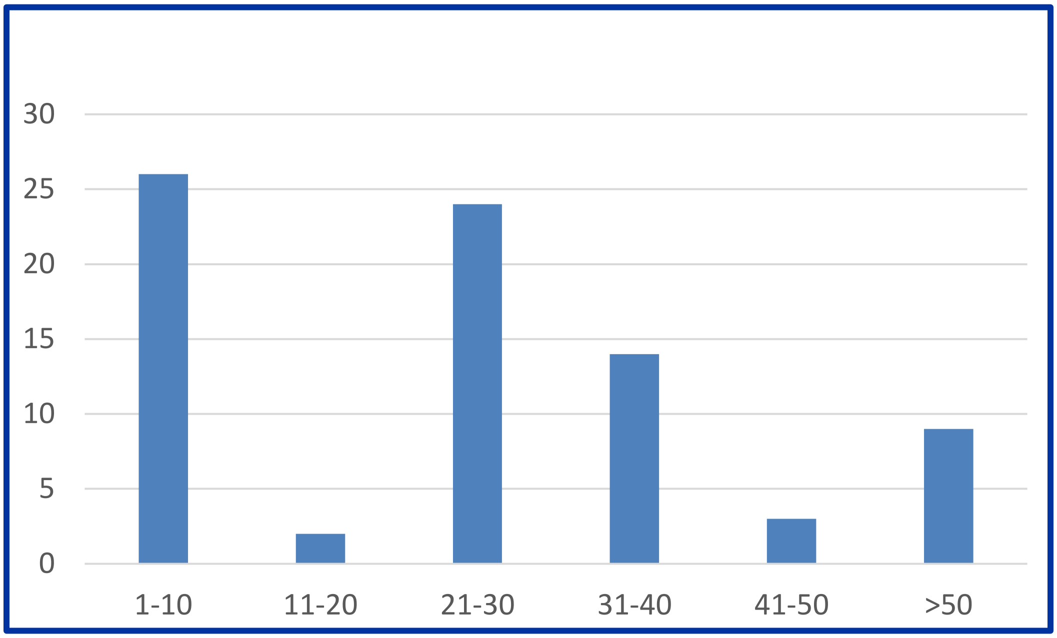

Figure 8 – Substation Breaker/Recloser Age

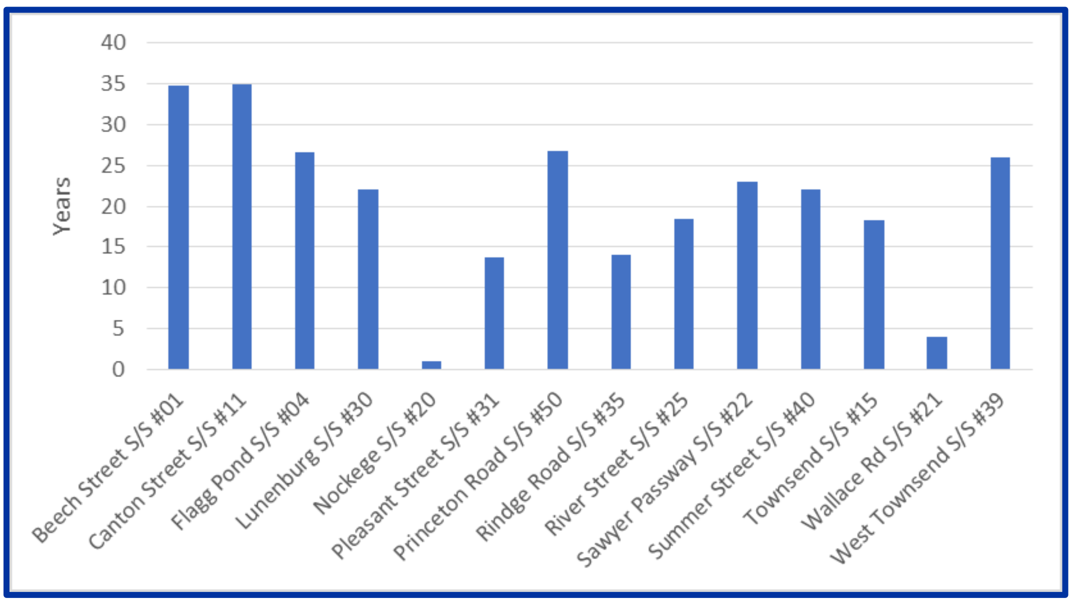

Figure 9 – Breaker/Recloser Average Age per Substation

Substation transformers are maintained periodically per the Company's maintenance policies. In addition, each year an oil sample is withdrawn from every transformer and analyzed to determine the health of the transformer. The loading of the transformers are also monitored to ensure they are not loaded above the specific ratings calculated for the particular transformer. Even with

these practices, the condition of a transformer can degrade due to age and through currents it experiences due to external system events. The Company normally replaces transformers because of capacity needs or failure and does not replace transformers due to age alone.
The substation transformer ages are displayed in the Chart below.

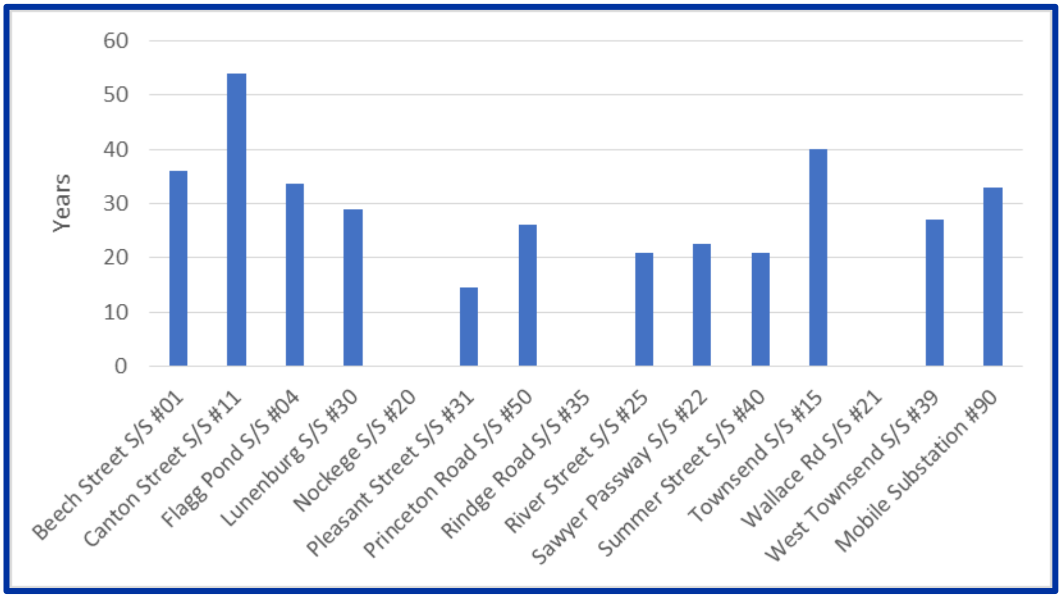

Figure 10 – Substation Transformer Ages

4.1.8.2 Distribution equipment

As described above, the main equipment installed on the distribution system includes poles, voltage regulators, reclosers, and distribution transformers.

Distribution Poles: Poles are replaced as needed due to condition or need to larger poles due to a construction project. There are 19,136 distribution poles on the Unitil system. Each year 10 % of the poles are conditionally tested. On average 3% - 4% of the poles tested require replacement.

Voltage Regulators (regulators): There are 83 Voltage regulators currently installed in the distribution system. Voltage regulators are normally only replaced with larger units due to loading constraints. New regulators are being installed on the system as part of the VVO Grid Modernization project. The average age of the voltage regulators on the distribution system is 8 years old.

Capacitor Banks: In the past capacitor banks were installed for voltage support as well as power factor support. There are 46 capacitor banks on the distribution system currently. Capacitor banks are being replaced for different size units and additional capacitor banks are being installed as part of the VVO Grid Modernization project. The average age of the capacitor banks on the system is greater than 15 years.

Reclosers: The older style reclosers on the distribution system do not have the advanced functionality that microprocessor recloser offer. As new reclosers are installed on the main-line distribution circuit, a microprocessor type recloser is installed with SCADA functionality. Currently there are a total of 64 reclosers on the distribution circuits.

Transformers: There are currently a total of 6,619 transformers on the distribution system. Traditionally Distribution transformers. The chart below details the ages of all the distribution transformers installed.

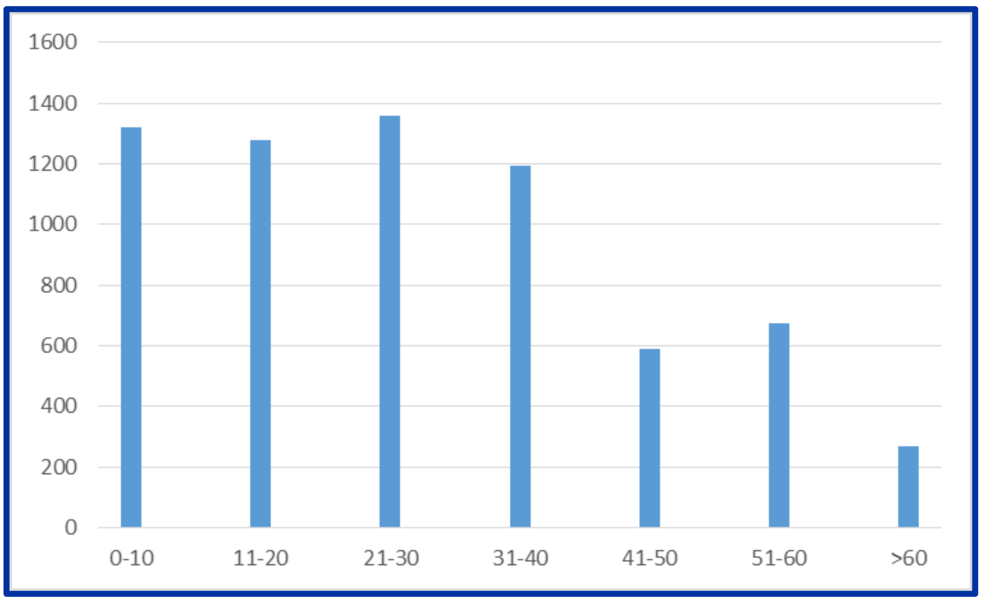

Figure 11 – Distribution Transformer Ages

4.1.9 Reliability and resilience

Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Projects and programs are designed and implemented to: 1) eliminate outages from occurring or 2) minimize the impact of an outage by reducing the number of customers affected and/or the duration of time they are affected. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every sustained outage on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or other resiliency measures to reduce the size or duration of the outage. Typically, this review results in protection or construction modifications or targeted out of cycle trimming activities.

Weekly – Internal reports on overall company and individual operating center reliability performance compared to annual goals and past history are developed on a weekly basis. This review is used to track the current year reliability and resiliency performance and benchmark it against company goals and historical performance.

Monthly – On a monthly basis, the Company summarizes the significant outages – outages that account for 75,000 customer-minutes of interruption or more, that occurred in each of the operating companies over the past month. The analysis also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages caused by failures of Company equipment. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report ("SER") – At the discretion of the Company's executive team any outage can have an SER report completed. A SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically, a SER recommends action items that are assigned and completed.

Annual – The Company conducts analysis on an annual basis that is focused upon the overall reliability and resilience performance of the system for a 12 month period. The reports evaluate individual circuit performance over the same time period. These reports are developed per Unitil's Reliability Analysis Guideline and include:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI").
- Analysis of the effect of sub-transmission and substation outages on circuit performance.
- Analysis of the worst performing distribution circuits over the reporting period
- Analysis of the major causes of sustained interruptions.

- Analysis of performance issues on specific circuits as well as recommendations for improvement
- Analysis of equipment failures to identify trends and provide recommendations when necessary.
- Analysis of areas with multiple tree related outages for consideration for additional tree trimming.
- Analysis of devices that have operated on more than three occasions over the timeframe.

Reliability improvement projects are designed and estimated. Each of the projects is compared based upon a cost per saved customer-minute and saved customer-interruption basis. These projects are submitted for capital budget consideration.

The reliability planning process described above has proven very successful. The historical reliability performance for the system is outlined below.

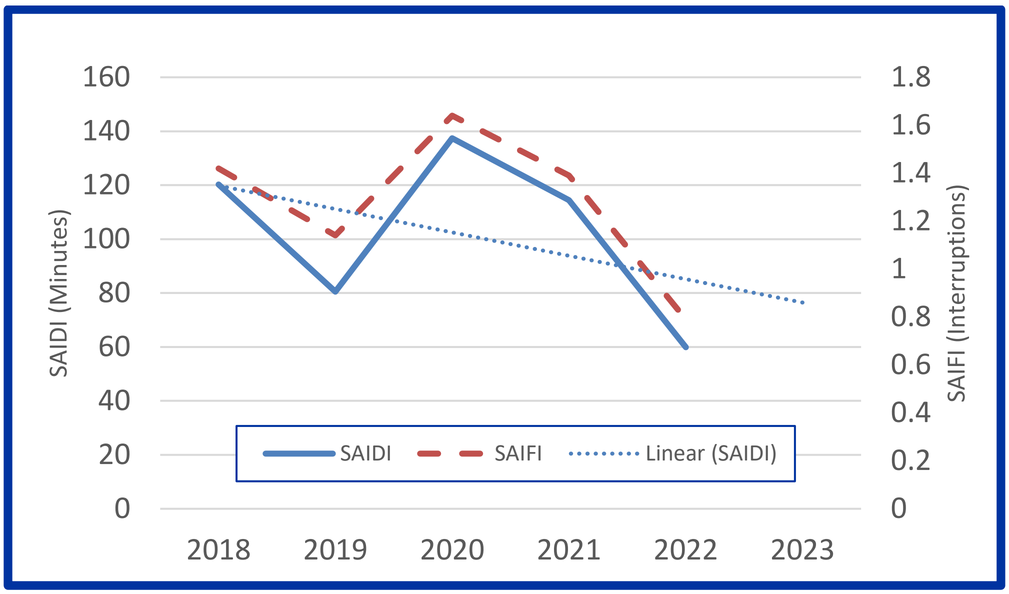

Figure 12 – Reliability Performance

The chart above, displays annual SAIDI and SAIFI using Massachusetts DPU exclusionary criteria. The 2022 reliability performance was the best performance in over 25 years. The system SAIDI of 59.9 minutes is roughly 33 percent lower than the 10 year average of 89.8 minutes. The system SAIFI for 2022 was 0.79 interruptions which was the best performance in over 25 years. The system SAIFI was approximately 36 percent lower than the 10 year average of 1.23 interruptions.

The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program) has a large impact on the reliability performance of the Company. The Company is experiencing better performance during both blue sky as well as major outage situations. The vegetation management program is resulting in less damage during storms allowing the Company to consistently complete restoration ahead of neighboring utilities and send line resources to assist others with restoration. The Company continues to evaluate the program for improvements where practical.

4.1.10 Siting and permitting

The substations in the Unitil territory are situated on land owned by the Company, while the transmission and sub-transmission lines are situated on land owned and/or easements on private property. The need for land rights for new substations and sub-transmission lines is expected in the very near future. The Company expects to face siting and permitting challenges similar to those of all utilities in the Commonwealth as described in section 7.3.

4.2 TECHNOLOGY PLATFORMS THAT WE HAVE IN PLACE TODAY

The Company has been an early adopter of grid technology. The Company implemented Advanced Metering Infrastructure ("AMI") for all customer over 15 years ago. The Company first developed its Geographic Information System ("GIS") system over 20 years ago and continues to improve on its content and accuracy. 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. 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. The figure below demonstrates the Company's existing technology which it continues to make improvements to through this plan.

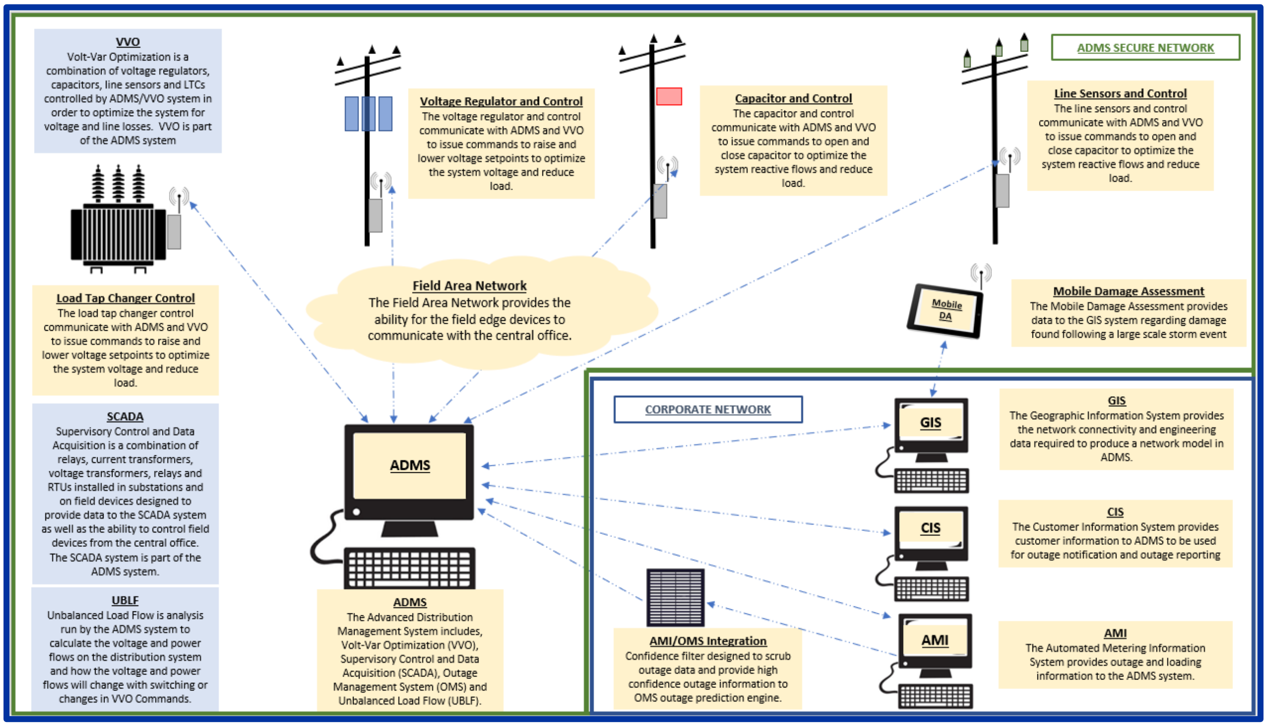

Figure 13 – Existing Technology

4.2.1 Geographical Information System (GIS)

GIS is an asset database and connectivity model of all distribution assets on the Unitil electric and gas systems. Unitil uses ESRI software to manage and maintain geospatial records for both our gas and electric assets. The models of the electric distribution system provide information of field installed assets and serve as tools for system planning, DER hosting Capacity maps, Outage Management System (OMS), and the Advanced Distribution Management System (ADMS)

4.2.2 Supervisory Control and Data Acquisition

Supervisory Control and Data acquisition (SCADA) is a system of software and hardware elements that allows an organization to:

- Remotely control assets such as substation circuit breakers, distribution reclosers, Capacitor banks, and voltage regulation equipment.
- Monitor and record real-time data such as voltage levels and power flow
- Trigger alarms based on real-time data and programmed trigger levels.
- Archive data for later study, such as event analysis and historic trending to support forecasting and planning.

> SCADA systems in the electric power industry provide a real-time interface between centrally located personnel and systems, such as a dispatch center or OMS and ADMS systems located at a corporate hub, and the remote devices they monitor and control, such as substation transformers, circuit breakers, line switches, capacitor banks, voltage regulators
>
> The architecture of a traditional SCADA architecture includes a distinct remote terminal unit (RTU) as the on-site interface between the remote SCADA master and the field devices and instrumentation at that site. However, with the advent of microprocessor-based devices and instrumentation, the traditional RTU functions are sometimes incorporated directly into those products, forgoing the need for an actual standalone RTU.

Currently the Company has SCADA commissioned at 12 substations including the circuit source devices and other devices in the substation. In addition, there is SCADA commissioned at various distribution devices on the feeders outside the substations.

As part of the Grid Modernization Plan the Company is expanding the SCADA functionality on the devices as well as the number of devices with SCADA functionality.

4.2.3 Advanced Meter Infrastructure (AMI)

AMI is a system of meters and central communications to allow advanced metering functions and measurements of individual revenue meters. The Company has implemented an AMI system across its service territories. As part of its current Grid Modernization Plan, the Company will enhance the integration to provide improved ability for all AMI meters to communicate with Unitil's Outage Management System ("OMS"). This enhanced data will be used in the OMS outage engine to help enhance outage predictions, including which device has isolated the fault and what customers have been restored.

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

The Company'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

the Company when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.
The Company'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), the Company 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).

4.2.4 Outage Management System (OMS)

The Outage Management System (OMS) is a computer model of the distribution system including the connectivity of the distribution circuits. The source of this model is provided by the GIS system. The OMS system communicates with the interactive voice response (IVR) system to receive outage calls from customers. The OMS system identifies the location of the outage using information from the Customer Information System (CIS) and uses the connectivity model of the system to "predict" the device that has opened causing the outage. When the outage is confirmed, the OMS system calculates the number of customers affected. The OMS system is a tool to help prioritize restoration, manage crew resources, and report outage information.

4.2.5 Volt/VAr Optimization (VVO)

Customers' demand and system losses can be reduced by adjusting the system power factor and lowering system voltage such more of the power flowing on the system is usable to the customer. This is performed by adding voltage regulation and capacitor banks to the system and controlling them as well as existing transformer load tap changers (LTCs) with more precise bandwidth through a central controller. The central controller receives real-time measurements throughout the system through the SCADA system and makes decisions of how to adjust the system voltage and power factor. It then sends control signals to the VVO equipment through the SCADA system to adjust the system voltage and power factor.

4.2.5.1 Description of Work Completed

The Company is currently installing VVO equipment on multiple distribution circuits and substations through the 2022-2025 Grid Modernization Plan. Currently VVO equipment is commissioned on seven distribution circuits emanating from two substations. By 2025 it is planned to have eleven circuits and four substations commissioned. Eventually all circuits will be included in the VVO plan.

4.2.6 Advanced Distribution Management System (ADMS)

The Company is currently implementing an ADMS through the Grid Modernization Plan. The Company manages its distribution system without much control or visibility past the distribution substations and does not have real-time visibility into the vast majority of the distribution resources connected to the network. Limited tools are available to monitor and control the influx of intermittent renewable resources which can cause two-way power flow concerns. These resources have a substantial impact on reliable operation of the system. This mode of operation is not sustainable.

This project will consist of upgrading the Company's current OMS to an ADMS that will support VVO and unbalanced load flow analysis. In the future the ADMS 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 Distributed Energy Resource Management System ("DERMS"). The existing system integrations with GIS, CIS, and OMS will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

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 integration of outside data sources such as real-time weather and VVO. The ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner. The ADMS will also provide valuable information during outage events and enhance situational awareness resulting in shorter outage durations.

The Company ADMS system is being implemented with the following functionalities:

- GIS editor to transfer the network model from the GIS to the ADMS on a routine basis as changes to the network topology are made in GIS

- New process to provide ADMS customer load profile and generator output information.
- Verification of network connectivity
- Enhancements of the existing OMS
- Migration from the pre-existing standalone SCADA system to the ADMS SCADA system
- Switch Order Module (manager)and simulation module
- Manual Load Shed and System Power Factor Management
- Volt/VAr Optimization
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training
- Hot standby fault recovery

5 5- AND 10-YEAR ELECTRIC DEMAND FORECAST

This section describes the approach and assumption to developing the 5-year and 10-year demand forecast. The demand forecast is used to determine where system constraints may exist at future loading levels.

5.1 5- AND 10-YEAR ELECTRIC DEMAND FORECAST AT THE EDC TERRITORY LEVEL

The electric distribution companies (EDCs) in Massachusetts made up of Eversource, National Grid, and Unitil together have reviewed and compared assumptions for the respective five- and ten-year electric demand forecast across the Commonwealth. The methodology employed by each individual EDC are aligned for the baseload econometric forecast, design weather conditions, and DERs. The EDCs utilize more than a decade of historical weather data (region dependent) to develop the design weather – the 90th percentile and use it as the primary planning case. Eversource and National Grid utilize an econometric forecast model for the baseload while Until projects recent historic growth forward (before impact of solar, storage, energy efficiency, demand response, heat pumps, electric vehicles). The EDCs then incorporate adjustments for DER. Each DER is independently forecasted considering their current market trend, policies, programs, and State decarbonization pathways. The EDCs all produce the forecasts at the jurisdiction level and allocate to more granular geospatial areas based on regional characteristics.

The amount and rate of deployment of total installed solar capacity is specific to each utility and described further in section 5.1.5. Eversource and National Grid use the same software to predict parcel wise allocation of ground mounted solar installations. The underlying parcel and land use data and method of simulating region-specific PV adoption is the same; based on land parcel availability and profitability analysis. Unitil forecasts future solar capacity based on historical trends.

Electrification in the transportation and buildings sector, in the form of electric vehicles and electric heating (heat pumps), are anticipated to be load drivers but are still relatively new technologies. Existing adoption of electric vehicles and heat pumps show very low penetration in the Commonwealth as discussed in section 4 above for each region. For the EDCs estimates for the near-term adoption are based on a combination of historical adoption, current market outlook, company plans and policy direction. Eversource and National Grid model granular spatial allocation using aggregated household characteristics, socioeconomic information, and travel patterns. Eversource leverages traffic data from the same data vendor as the Massachusetts Department of Transportation ("MA-DOT"). National Grid applies data for commuting demands from the Census Bureau.. Unitil utilizes ISO, EEI assumptions, census data and registered vehicle data to develop a projection for EV adoption and load forecast. Aggregate demand – summer and winter

Aggregate summer and winter demand at the Company's bulk substation, Flagg Pond, is determined based on the system peak load forecasts with a review of expected power flow through (both forward and reverse) directions. The review includes the incorporation of both DER and electrification. In the case of the Flagg Pond, additional Photovoltaic ("PV") adoption/installations has little impact on the reduction of winter or summer peak load as the current penetration of PV served from Flagg Pond substation has shifted the aggregate summer and winter peak demands to hours of the day in which PV facilities are generating minimal amounts of energy (i.e. 7:00PM). Flagg Pond aggregate winter and summer peak demand forecasts are included in the table below.

Year	Winter Forward Powerflow (MW)	Summer Forward Powerflow (MW)
2025	88	104
2026	90	105
2027	93	106
2028	95	107
2029	98	108
2030	101	110
2031	104	111
2032	108	113
2033	112	115
2034	113	117

Table 10 – Flagg Pond Bulk Substation Load Forecast

The latest aggregate winter and summer demand forecasts indicate that the Flagg Pond substation exceed its capacity under N-1 conditions for loss of supply transformer as early as 2034.

5.1.1 Weather normalized econometric forecast (Base Peak Load Forecasts)

The historical basis for the Company's Base Summer Peak Load Forecasts is a series of yearly regression models developed to correlate actual daily loads to a Weighted Temperature-Humidity Index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI experienced within a season, which varies with short-term weather trends from one year to another. Second is the model estimate of peak load at any specific WTHI. This estimate has its own variation of possibilities due to the influence of other existent factors not incorporated into the model. These variations are characterized as randomness in making future projections. The probability distribution for annual highest WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI and varying based on its individual standard deviation according to the fit of the seasonal model to the actual historical values.

To establish load projections, a Monte Carlo simulation is run to produce random annual highest WTHI and random peak load estimates at those WTHI from each year's seasonal model that makes up the historical basis. Each trial in the simulation is projected forward using linear trending. This results in a range of peak load possibilities for each future year assuming linear growth, and varying due to annual highest WTHI possibilities and variability in loads versus WTHI. The likelihood of specific peak load levels occurring in any particular future year can be estimated from an assumed probability distribution using the mean and standard deviation of the trial results for that year. Base Summer Peak Load Forecasts are set at a 90% probability limit. This is intended to roughly equate to a 1-in-10 year likelihood that the forecasted load level will be exceeded.

DER that are operating during peak load conditions offset system tie point power flows consequently reducing historical system loads. Therefore, the power offset or produced from all known significant DER units must be accounted for in the load forecasts. Unitil adds the output from all known significant DER units to its historical systems tie point flows prior to calculating the load forecasts. These units are then modelled in different dispatch scenarios in the system modelling process.

The Company's Base Winter Peak Load Forecasts are derived from the Base Summer Peak Load Forecasts utilizing the historical percentage difference between the historical average of the three peak days of the previous three years for the summer seasons and the historical average of the three peak days of the previous three years for the winter season.

Hourly interval load forecasts for the peak day are then developed for both the winter and summer seasons. These hourly interval forecasts are derived based on the average hourly interval loads for the three peak days of each season for the previous three years.

5.1.2 Large load (step/spot load)

Two large loads were excluded from the weather normalized forecasts and were added into the base forecasts after the weather normalized forecasts were completed. The first is a large customer load (approximately 8.0 MW) served by Princeton Road 50W53 circuit.

The second is a newly proposed customer project located in southern Lunenburg. This load was assumed to be approximately 3.0 MW and was included as a step adding in the load forecasts.

5.1.3 Energy efficiency

The Company is a program administrator in the Mass Save Energy Efficiency Plan. The energy efficiency ("EE") programs the Company offers to its customers are developed as part of a comprehensive and collaborative approach to optimizing energy use by electricity and natural gas customers. The Company works collaboratively with the state regulatory agencies and interested stakeholders to develop energy efficiency programs designed to meet state goals. The Company pursues cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Company's energy efficiency programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers.

The Company's 2022-2024 Three-Year Energy Efficiency Plan calls for just over $22 million in investment of energy efficiency and electrification measures. Based upon the plan, the expected passive and active energy savings is approximately 0.5 MW.

Past energy efficiency efforts and outcomes are imbedded in the historical loading information used for the demand assessment forecast. Energy efficiency plan development is handled in a separate proceeding, resulting in three-year funding levels and projected savings. The Company expects these savings to continue into the future, but they are not specifically called out in the forecast as it is difficult to separate historical energy efficiency savings from the historical load data.

5.1.4 DER Growth: Solar PV, Battery Storage, Grid Services

Unitil separately develops ten year DER forecasts. These DER forecasts are established based on the five year and three year historical slope of DER capacity growth as well as the overall number of DER facilities and the number of customers served. These forecasts are then incorporated into the Company's peak load forecasts.

To incorporate DER forecasts into the System Load Forecasts the projected incremental DER (DER projection minus the in-service DER) is used to develop hourly DER projections.

Similar to the hourly base load forecasts normalized hourly peak DER output is calculated using the average hourly DER output of the large DG on the system for the three peak days of the previous three years for both the winter and summer seasons. Each hour of normalized average hourly peak DER output is then multiplied by the projected incremental DER.

The calculated relationship factor between DER with a nameplate capacity of less than 500kW and DER with a nameplate capacity of 500kW or more is utilized to calculate the expected peak output of the incremental forecasted DER for each hour.

In addition to the DER forecasts described above the Company assumed sufficient Energy Storage Systems ("ESS") would be installed to level the load curve. Hourly dispatch (charge/discharge) were developed based on the forecasted peak day hourly interval data. In addition to the total amount of ESS being installed it was assumed that a portion of ESS could be charging during peak load or discharging during minimum load.

5.1.5 Electric vehicles

The Company separately prepares ten-year EV charging load forecasts that are incorporated into the base system load forecasts. The ISO-NE EV Adoption Forecasts by state were used as the basis for the Company's EV load projections. These ISO-NE forecasts along with ISO-NE EV stock (registered) by state data was used to project the number of EVs on the road and ultimately the number of EV chargers within Unitil's service territories.

ISO-NE information on the number of EVs currently registered in Massachusetts was used to estimate the current number of EVs in the service territory. Once the number of EVs was determined, the ISO-NE EV Adoption Forecasts were used to project the number of EVs. Two forecasts for each territory were created:

- High Rate – utilizes 100% of the ISO-NE EV Adoption Forecasts
- Baseline Rate – utilizes 67% of the ISO-NE EV Adoption Forecasts

Utilizing the assumptions below, the Company estimated the number of home level 1 and level 2 chargers in Unitil's service territory. EEI projections for the percentages of the total number of each type of level 2 charger allowed for the calculation of the estimated number of level 2 public and work place chargers.

Utilization percentages (percentage of total of each type of units charging) for each hour of the day for home, public (including DC fast chargers) and workplace chargers and the assumed demand for each type of charger was then used to calculate the forecasted load due to EV charging for each hour of the day.

<u>Assumptions</u>
The following assumptions were used to calculate Unitil's EV load forecasts:

- Every EV owner will have some form of home EV charging
    - 33% will have Level 1 Chargers
    - 67% will have Level 2 Chargers

Note: For the purpose of this forecast Level 1 Chargers are assumed to only be utilized as home chargers

- Percent of total Level 2 chargers (based on EEI projections)
  - 78% Home
  - 8% Public
  - 13% Workplace
  - 1% Other

- Demand for each charger type
  - Level 1 Charger – 1.7kW
  - Level 2 Charger – 9.6kW
  - DC Fast Charge Facility – 600kW

- Number of DC fast charge facilities per forecast type
  - High Rate – 2 DC fast charge facilities per year
  - Baseline – 0.5 DC fast charge facilities per year or 1 facility every two years

- Hourly Utilization Percentages

Hour of Day	Home	Public	Workplace	Hour of Day	Home	Public	Workplace
0:00	75%	25%	5%	12:00	15%	75%	60%
1:00	75%	25%	5%	13:00	15%	60%	60%
2:00	75%	25%	5%	14:00	15%	60%	60%
3:00	75%	25%	5%	15:00	25%	50%	60%
4:00	75%	25%	5%	16:00	30%	40%	50%
5:00	60%	25%	5%	17:00	40%	40%	40%
6:00	50%	35%	5%	18:00	50%	30%	15%
7:00	50%	35%	10%	19:00	60%	30%	10%
8:00	40%	50%	15%	20:00	60%	30%	5%
9:00	30%	60%	60%	21:00	60%	30%	5%
10:00	15%	75%	60%	22:00	75%	30%	5%
11:00	15%	75%	60%	23:00	75%	25%	5%

Table 11 – Hourly EV Utilization

For the purposes of the ten year system peak load forecasts the Company uses the baseline rate forecasts when incorporating EV charger load forecasts. The Company currently anticipates that EV adoption will continue to be slower than anticipated over the next several years due to penetration of charging infrastructure and until vehicle owners are presented with vehicle replacement decisions.

5.1.6 Electrification

The Company incorporates both residential and commercial/industrial electrification into ten year system peak load forecasts. For both residential and commercial/industrial electrification the following adoption rates were used for the ten year forecasts.

- Adoption (% of Total Forecasted Load Incorporated per Year)
    - 2025-2029 – 1%
    - 2030-2034 – 2%

<u>Residential Electrification:</u>
The Company considers two types of residential electrification in its load projections, appliance load and heating/air conditioning load. In order to develop load forecasts for each of these load types the company made the following assumptions.

- An average square footage of a residential dwelling in the service territory of 1,500 square feet.
- Heating/AC Sizing[12]
    - 20 btu/sq. ft. for air conditioning
    - 50 btu/ sq. ft. for heating
- Heating/AC Heat Pump SEER of 18 (13.68 btu/W) (based upon manufacturer data for an “average” efficiency unit)
- Current customer AC usage
    - 30% with central AC
    - 40% with window AC
    - 30% with no AC
- All natural gas customers have gas heat, ranges and dryers.

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[12] Based upon International Energy Conservation Climate Zone Map

- Typical Electric Dryer Peak Load of 5kW[13]
- Typical Electric Range Peak Load of 6kW[14]
- 80% of all residential customers will convert to electric heat by 2050[15]
- Hourly Utilization Percentages

Hour of Day	Appliance	Heat/AC	Hour of Day	Appliance	Heat/AC
0:00	5%	50%	12:00	25%	65%
1:00	5%	50%	13:00	25%	65%
2:00	5%	50%	14:00	10%	80%
3:00	5%	50%	15:00	10%	80%
4:00	5%	50%	16:00	25%	80%
5:00	10%	65%	17:00	25%	80%
6:00	15%	65%	18:00	25%	80%
7:00	25%	80%	19:00	25%	80%
8:00	25%	80%	20:00	10%	80%
9:00	10%	65%	21:00	10%	80%
10:00	10%	65%	22:00	10%	65%
11:00	10%	65%	23:00	5%	50%

Table 12 – Hourly Electrification Utilization

The assumptions above along with coincident assumptions, which decrease over time based on the amount of electrification were used to develop hourly residential electrification peak day forecasts. The hourly residential electrification forecasts are then added to the hourly base seasonal peak load forecasts.

Commercial/Industrial Electrification:

The Company utilized peak gas loads for all commercial/industrial gas customers as the basis for is commercial/industrial electrification load forecasts along with typical hourly electric profiles

[13] Based upon typical nameplate data and National Electric Code loads.
[14] Based upon typical nameplate data and National Electric Code loads.
[15] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

for the same customer types and the following assumptions to hourly commercial/industrial electrification load forecasts. These forecasts were then added to the hourly base seasonal peak load forecasts.

- Estimates Peak Hour Gas Usage[16]
    - "Small" Commercial/Industrial – 437 DTH
    - "Large" Commercial/Industrial – 61 DTH
- 293 kW/DTH
- % of Customers to Electrify[17]
    - "Small" Commercial/Industrial – 87%
    - "Large" Commercial/Industrial – 52%

5.1.7 VVO

In addition to DER and electrification load forecasts the Company also includes load reduction due to VVO implementation. Historically, the Company has anticipated a 2% reduction in current loads when VVO is implemented. To incorporate VVO reductions in the ten year peak load forecasts the Company assumed the following savings.

- Base Load Forecasts – 2% reduction
- Residential Electrification – 1% reduction
- Commercial/Industrial Electrification – 0.75%
- EV – 2%

These saving equate to an overall load reduction when VVO is fully deployed of approximately 1.75%.

5.1.8 10-Year Peak Load Forecasts

Hourly interval load forecasts for both the winter and summer season for each of the ten years where developed by combining the hourly interval base, DER, ESS, EV and electrification forecasts above and incorporating VVO load reduction. The overall system peak load forecasts is the peak

[16] Based upon "average" Unitil customer
[17] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

hourly load (winter or summer) or each year. Unitil's ten-year system peak load forecasts are included below.

In the case of the electric system, additional PV adoption/installations has a relatively small impact on the "reduction" of overall winter or summer peak loads. The current penetration of PV interconnected to the electric system has shifted the typical summer peak hour (approximately 7PM) and the winter peak hour (approximately 6PM) has remained at times in the evening with minimal PV production.

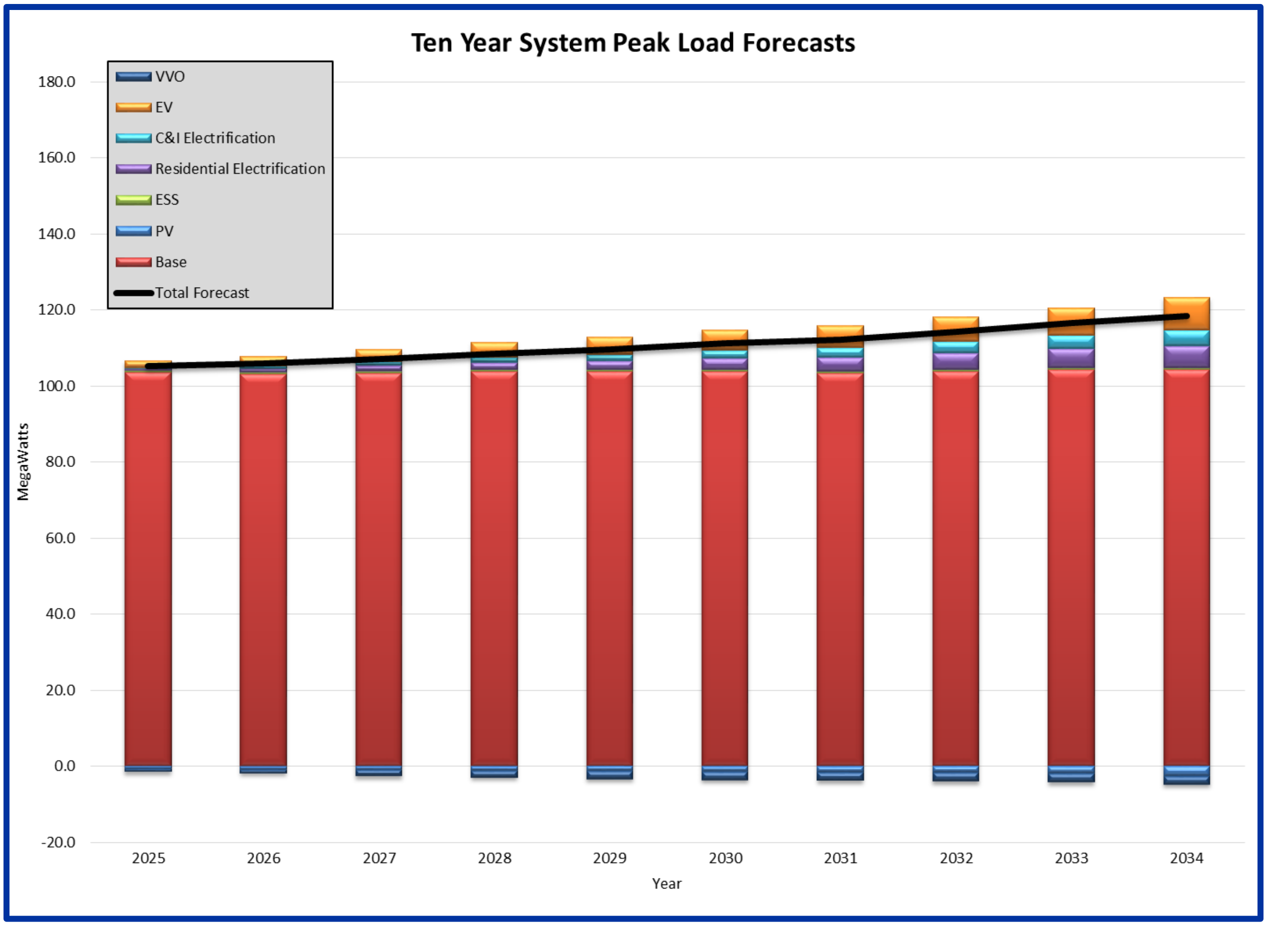

Figure 14 – Ten Year System Peak Load Forecast

	Total Peak Forecast (MW)	Contribution to Total (MW)							Season ESS	Hour
		Base	PV	ESS	Residential Electrification	C&I Electrification	Base	PV		
2025	105.3	103.6	-0.6	0.5	0.5	0.3	1.9	-0.8	Summer	7PM
2026	106.0	103.2	-0.8	0.5	1.0	0.7	2.5	-1.0	Summer	7PM
2027	107.1	103.5	-0.9	0.5	1.4	1.0	3.3	-1.6	Summer	7PM
2028	108.6	104.0	-1.1	0.5	1.9	1.3	3.9	-1.8	Summer	7PM
2029	109.5	103.8	-1.2	0.5	2.4	1.6	4.6	-2.1	Summer	7PM
2030	111.2	103.9	-1.4	0.5	3.0	2.1	5.3	-2.2	Summer	7PM
2031	112.1	103.4	-1.5	0.5	3.7	2.6	5.7	-2.2	Summer	7PM
2032	114.2	103.8	-1.7	0.5	4.4	3.1	6.4	-2.3	Summer	7PM
2033	116.5	104.3	-1.8	0.5	5.1	3.6	7.2	-2.3	Summer	7PM
2034	118.5	104.5	-2.6	0.5	5.7	4.1	8.7	-2.1	Summer	7PM

Table 13 – Ten Year System Peak Load Forecast

5.1.9 Net Powerflow

In addition to peak load forecasts Unitil develops Net Powerflow forecasts. Net Powerflow forecasts are utilized to identify potential planning violation under reverse powerflow conditions. The Net Powerflow forecasts are developed by combining historical or estimated net powerflow at substation transformers and circuit terminals. Net Powerflow forecasts are developed using Net Powerflow information for the previous three years, DER, EV and electrification forecasts.

For the purposes of Net Powerflow forecasts Unitil assumes slower EV and electrification adoption rates than what is assumed when developing peak load forecasts. The ten-year Net Power flow forecasts are below.

Year	Net Powerflow (MW)
2025	-4
2026	-5
2027	-6
2028	-7
2029	-8
2030	-8
2031	-9
2032	-9
2033	-10
2034	-15

Table 14 – Ten Year Net Powerflow Forecast

6 5- AND 10-YEAR PLANNING SOLUTIONS: BUILDING FOR THE FUTURE

The section takes the load forecast described and developed in Section 5 and uses it to identify system constraints. The section begins with a description of the existing capital spending plan, previously approved capital spending plans (i.e. grid modernization and electric vehicles) and proposed capital spending.

6.1 SUMMARY OF EXISTING INVESTMENT AREAS AND IMPLEMENTATION PLANS (EXISTING ASSET MANAGEMENT AND CORE INVESTMENTS, INCLUDING RATE CASE, GRID MODERNIZATION, APPROVED CIP PROGRAMS, DECARBONIZATION, HEATING, ELECTRIC VEHICLE AND ENERGY EFFICIENCY PROGRAMS)

6.1.1 EXISTING CAPTIAL PLAN

The Company's existing capital budget consists of the following types of projects:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. These projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consist of new customer requests for service including new services and small line extensions; outdoor lighting includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration includes capital repairs and replacements required to restore service to customers following storms or outages; billable work includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, transformer and meters are for the purchase of transformers and meters.
- Distribution - These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our agreements with Verizon or other pole attachees; highway projects

are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $30,000 that are identified by engineering or others that are needed to meet service obligations.

- Substations - These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.
- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan. See the description below.
- Others - Communications include additions and replacements of communication-related equipment such as Supervisory Control and Data Acquisition (SCADA), radio systems for field communications, and communication equipment for the Company's Advanced Metering Infrastructure (AMI) system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices.
- Common - Projects that can be allocated to both electric and gas are identified as common projects. These projects include office furniture and office equipment, including normal additions and replacements; and structures includes upgrades and improvements to the Company's buildings, including the Company's operations center building. Common facilities have been apportioned to electric or gas based on an allocation provided by Accounting. In general, these facilities represent only a small portion of the overall budget.

6.1.2 GRID MODERNIZATION

In D.P.U. 21-82, the Company filed its 2022-2025 Grid Modernization Plan. The plan proposed a continuation of previously authorized projects in addition to new projects. The Department subsequently authorized investments for: 1) SCADA, 2) AMI/OMS Integration, 3) VVO, 4) Field Area Network, 5) ADMS/DERMS, 6) Mobile Damage Assessment Platform, 7) DER Mitigations, 8) AMI Meter Replacements, 9) Customer Engagement and Experience and 10) Data Sharing Platform.

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
SCADA	$ 100	$ 0	$ 0	$ 0	$ 0	**$ 100**
AMI/OMS Integration	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
VVO	$2,400	$ 0	$ 0	$ 0	$ 0	**$2,400**
Field Area Network	$ 179	$ 0	$ 0	$ 0	$ 0	**$ 179**
ADMS/DERMS	$ 125	$ 0	$ 0	$ 0	$ 0	**$ 125**
Mobile Damage Assessment	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
DER Mitigation	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI Meter Replacements	$ 339	$ 0	$ 0	$ 0	$ 0	**$ 339**
Customer Engagement	$ 465	$ 0	$ 0	$ 0	$ 0	**$ 465**
Data Sharing	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Total Costs (000s)	**$ 3,608**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 3,608**

Table 15 – Approved Grid Modernization Capital Spend ($000's)

Project / Project Category	2025	2026	2027	2028	2029	2025-2029 Total
SCADA	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI/OMS Integration	$ 11	$ 0	$ 0	$ 0	$ 0	**$ 11**
VVO	$ 5	$ 0	$ 0	$ 0	$ 0	**$ 5**
Field Area Network	$ 10	$ 0	$ 0	$ 0	$ 0	**$ 10**
ADMS/DERMS	$ 178	$ 0	$ 0	$ 0	$ 0	**$ 178**
Mobile Damage Assessment	$ 50	$ 0	$ 0	$ 0	$ 0	**$ 50**
DER Mitigation	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
AMI Meter Replacements	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Customer Engagement	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Data Sharing	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
Third Party Verification	$ 75	$ 0	$ 0	$ 0	$ 0	**$ 75**
Total Costs (000s)	**$ 329**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 329**

Table 16 – Approved Grid Modernization O&M Spend ($000's)

6.1.3 ENERGY EFFICIENCY

The Energy Efficiency programs the Company offers are developed as part of a comprehensive and collaborative approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors.

The Company works collaboratively with the State regulatory agencies and interested stakeholders to develop energy efficiency programs designed to meet state goals. The Company implements cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Company's EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers.

The Company's existing portfolio of EE programs focuses on customers in three categories: non-low income residential customers, low income residential customers, and commercial and industrial customers. The primary electricity-saving residential offering provides discounted retail pricing to residential customers who purchase high efficiency lighting and electric appliances. The Company collaborates with retailers, distributors and the other electric utilities to ensure that high efficiency products are marketed to customers, and that point-of-sale discounts are provided to customers on high-efficiency promoted products.

By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs. For more substantial and expensive projects involving heat pumps or whole-home weatherization, the Company offers on-bill and third party financing options that allow customers to spread their share of the investment over a longer period of time and experience cash-flow positive savings. For income eligible customers, the Company pays 100% of the cost of energy improvements, eliminating one of the major barriers to participation for these customers.

In the commercial and industrial sector, the Company works closely with retailers and distributors to ensure that high efficiency lighting, motors and drives, HVAC, controls and other equipment are an accessible and attractive choice for contractors, builders and end use customers. By providing both technical assistance and cash incentives, our efficiency programs reduce the barrier that a higher up-front cost presents to C&I customers, including municipalities and nonprofit organizations. As in the residential sector, on-bill financing programs allow qualifying commercial and industrial customers to offset some or all of the up-front cost of new or retrofitted equipment that is not covered by the program's cash incentive.

For both residential and commercial and industrial customers, the Company provides technical assistance, training and cash incentives to ensure that new buildings are built and equipped to high EE standards. This assistance is facilitated not only by the Company's key account managers, but supplemented by engineering and design-build firms that are familiar with both good building design and with our incentive programs.

In the residential programs, a fuel-blind approach to energy use results in significant heating fuel savings in programs focused on new construction and weatherization of existing homes. Just under half of the resulting energy savings comes from a reduction in electricity use from high efficiency HVAC, appliances and lighting.

For the commercial and industrial sector, the majority of savings come from custom projects among manufacturers, retail establishments, municipalities, and schools. While high efficiency lighting and controls continue to be the most important single contributor to overall EE savings, the Company is dedicated to reducing both energy use and demand by incenting high efficiency Heating, Ventilation and Air Conditioning ("HVAC") measures, motors and drives, appliances, plug loads, and process equipment. Technical assistance, professional referrals and financial assistance help customers to overcome non-cost barriers to the adoption of energy efficient equipment and operations. Based upon the 2022-2024 Mass Save efficiency plan, the expected passive and active energy savings is approximately 0.5 MW. The Company is not intending to forecast EE spending as the EE plan and funding levels are adjudicated in a separate process. The table below assumes the 2024 Plan spending continues at the same funding level throughout the 2025 - 2029 timeframe.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
O&M Costs (000s)	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	**$40,000**
Total Costs (000s)	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 8,000**	**$ 40,000**

Table 17 – EE Plan Spending

6.1.4 ELECTRIC VEHICLE CHARGING AND MAKE READY PROGRAMS

The transportation sector continues to be the largest contributor of GHG emissions in the Commonwealth of Massachusetts.[18] In docket D.P.U. 21-92, the Department approved the Company's five-year EV program with a $998,000 budget consisting of: (1) public segment ($528,000); (2) residential segment ($300,000); and (3) marketing and outreach ($160,000).[19] The Department found it appropriate to limit the availability of residential program Electric Vehicle Supply Equipment ("EVSE") rebates for one to four-unit properties to low-income customers, who face the greatest financial barriers to EV adoption. The Department approved the Company's proposal to provide 100 percent EVSE rebates to residential customers in one to four-unit dwellings who qualify for its low-income residential discount rate and are enrolled in its EV Time of Use ("TOU") rate, up to the Company's proposed project cap.

This is the first approved EV program for the Company and the learnings from this program will be used to inform changes to future programs. The program is designed to support the growth of electric vehicles in Massachusetts by providing incentives to public and residential charging.

The Company's AMI system allowed the Company to be uniquely positioned to provide EV TOU rates. TOU rates will encourage energy conservation and the optimal and efficient use of grid facilities, and will mitigate increases in peak demand. The Company's rate offering includes an EV TOU rate and demand charge alternative pram for general deliver service applications. Given the dynamic nature of the transportation market and the wide variety of customer travel needs, it is unlikely that any one option will be suitable for all customers. Innovative rate designs will afford customers the opportunity to adopt new technologies, manage energy consumption and enhance efficient utilization and consumption of electricity to save money.

The Company's EV program is designed to alleviate barriers to EV adoption. The program offers $1,000 rebates to residential customers enrolled on the EV TOU rate and living in 1-4 unit dwelling for the installation and procurement of Level 2 EV chargers.

The program is designed to provide an increased incentive to income-eligible customers. Income-eligible customers receive rebates covering 100% of the installation and procurement of smart, Level 2 EV chargers up to $1,700.

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[18] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 15
[19] docket D.P.U. 21-92 Order at 169

The program also offers a make-ready EV infrastructure program essential to the development of public EV charging stations throughout Massachusetts. The make-ready program targets investment of approximately $528,000 over five years to deploy EV charging at approximately 5 Level 2 and 1 DCFC public sites (total of 6 sites) in the Company's service area. The Company further proposes to install required upgrades on the distribution system and to contract with third-party electrical contractors to install behind-the-meter "customer-side" infrastructure. The Company will target make-ready site hosts with publicly-available, long-dwell time parking including environmental justice and low and moderate income communities.

The proposed make-ready program represents a significant increase in Company-supported, customer-sided and behind-the-meter infrastructure. A make-ready program is necessary to expand the Commonwealth's network of charging stations, that the make-ready program is in the public interest, and will reduce barriers to investments in EV charging infrastructure.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 106	$ 106	$ 106	$ 0	$ 0	**$318**
O&M Costs (000s)	$ 92	$ 92	$ 92	$ 0	$ 0	**$270**
Total Costs (000s)	**$ 196**	**$ 196**	**$ 196**	**$ 0**	**$ 0**	**$ 588**

Table 18 – Approved EV Plan Spending[20]

In an attempt to keep pace with the State's goals for EV adoption, the Company is proposing to double the approved per year spending during the last two years of this plan.

[20] Docket D.P.U. 21-92 Order at 169. DPU approved five-year EV program (2023-2027) with a $998,000 budget consisting of: (1) public segment ($528,000); (2) residential segment ($300,000); and (3) marketing and outreach ($160,000). Plan assumes flat spending over 5 year period.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 212	$ 212	**$0**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 184	$ 184	**$0**
Total Costs (000s)	**$ 0**	**$ 0**	**$ 0**	**$ 396**	**$ 396**	**$ 792**

Table 19 – Proposed EV Plan Spending

6.1.5 HEATING INCENTIVE PROGRAMS

As indicated in the 2022-2024 Mass Save energy Efficiency Plan[21] after the transportation sector, the largest source of GHG emission is the building sector. The plan relies on electrification of the heating sector to drive reductions in the GHG emissions. The current plan focuses on transitioning customers who are more likely to experience reduced heating costs when transitioning from oil, propane, or electric resistance heating to heat pump technology. The Company believes heating incentives will continue to play an increasingly more important role in subsequent plans.

The spending associated with heating incentives is included in the EE spending plan above.

6.1.6 DEMAND RESPONSE PROGRAMS

The Company offers an active demand response program through Mass Save. The program incentivizes customers to reduce their load during identified times of system peak demands. Lower peak demands help to defer system investment while reducing charges from transmission and generation. This program can influence both the long-term forecasting methodology ISO-NE uses to establish the Installed Capacity Requirement, as well as the price of capacity in the Forward Capacity Market.[22] Active Demand Response activities can be aggregated and bid into the Forward Capacity market, resulting in financial incentives to those who participate

Through the Mass Save program, the program administrators will scale up active demand response offerings for C&I customers as well as residential customers. The C&I customer program is designed to target the peak hour of the system. Transmission costs are allocated on the peak hour load, therefore a reduction in load at the peak hour can have a significant impact

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[21] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 11
[22] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf at page 32

on the cost allocation. Reduction events are generally noticed a day in advance and then dispatched at the specific time of day the reduction is needed.

Active demand response can be effective a reducing system peak load. However, at a local level the program administrators must have a high confidence in the specific loads being reduced in order to be included and considered a grid asset.   The Mass Save program have and “opt-out” capability, so customers can choose not to participate on any given day. This does not lend itself to a reliable asset the Company can rely upon to ensure system performance.

The spending associated with demand response incentives is included in the EE spending plan above.

6.2 DESIGN CRITERIA CHANGES

The Company is considering the following impacts to its planning and design criteria:

- Ice and Wind Loading – The Company currently uses the National Electric Safety Code for ice and wind loading criteria when designing our electric system. The Company will consider increasing the ice and wind loading criteria used in future designs.
- Standard Equipment Sizes – The increase in electrification will increase loads on the electric system. To the extent necessary, the Company will evaluate the standard equipment sizes to determine if changes are appropriate.
- Equipment Ratings – Existing load curves allow for times of light load and cooling. As the load curve flattens, the opportunity for cooling at lighter loads diminishes. To the extent necessary, the Company will evaluate the impact that rising temperatures and changing load cycle curves have on equipment ratings.
- Outage Criteria – With the increase in electrification, the tolerance for outages may be impacted. To the extent necessary, the Company will evaluate changes to its outage exposure design criteria (i.e. MW/Hour or CMI/Hour.

6.3 TECHNOLOGY PLATFORMS WE ARE IMPLEMENTING (INCLUDING AMI WITH DATA ACCESS, VVO, FLISR, ADMS, DERMS (TO OPTIMIZE 20-YEAR SOLUTION SET), AUTOMATED INTERCONNECTION TOOLS, ETC.

6.3.1 Description of implementation justification and expected benefits

Automation

The objective of this project is to implement key SCADA functionality at all of the Company's substations, and at other locations needed to support the ADMS/OMS/VVO applications and other modernization projects. SCADA provides for the remote monitoring of conditions on the electric system and the remote control of equipment and functions by operating personnel or automation systems. The SCADA project 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.

In addition to facilitating the ADMS/OMS/VVO and other modernization projects, SCADA monitoring and control at the distribution level is foundational to reducing outage response and restoration times through improved outage awareness, fault location, isolation and system reconfiguration capabilities, both manually or through automation. After implementation, it is estimated that outages originating at SCADA-controlled devices may be reduced by 5 minutes of response time at the front-end and 5 minutes of re-energization time at the back-end of an outage for a total savings of 10 minutes. Based upon 2020 reliability performance, this would translate to a savings between 60,000 – 120,000 customer minutes or approximately $70,000 to $140,000[23] worth of customer savings annually (or 50% to 100% of the outages originating at SCADA controlled devices).

The following functionality is intended for the devices where these SCADA additions or modifications are planned:

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[23] Based upon 2018 Berkley Lab Interruption Cost Estimator using Company outage and customer counts. ICE Model estimates savings of $0.05 per minute for a residential outage and $8.53 for small commercial and industrial customers. 87% of the Company's customers are residential (26,500/30,500=0.87). 13% of the Company's customers are commercial/industrial (4,400/30,500=0.13). (60,000*0.87*$0.05)+(60,000*0.13*$8.53)=$69,144. (120,000*0.87*$0.05)+(120,000*0.13*$8.53)=$138,288.

- Real-time telemetry and historical interval data collection for each included power transformer and circuit position, including the following measurements:
  - Voltage
  - Current
  - Active and Reactive Power
  - Active and Reactive Energy (where required)
- Remote monitoring of live/dead states of included buses, lines and circuits
- Remote monitoring and control of included breakers, reclosers, switches, etc.
- Remote monitoring and control of included transformer LTCs and voltage regulating transformers
- Remote monitoring and control of included capacitor banks

Integration with the ADMS, and the ability to participate in automation schemes suitable to their functions

AMI/OMS Integration

This is a software project to enhance the current AMI to OMS interface. The Company 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.

By proactively detecting, and confirming with a high degree of confidence, valid outages, we expect to save time and money by reducing potentially unnecessary truck rolls and expedite crew deployment. This data may also provide additional near term related benefits such as reduction in SAIDI times as well as long term applicability towards building more proactive and predictive outage intelligence and analytics. The theory is that the outage information from the AMI system will allow the Company to know about the outage without having to rely on a customer phone call through the IVR system. It is estimated that the AMI system on average will be five (5) minutes faster than customer calls for at least 10% of the outages. This results in an annual savings of approximately 25,000 customer minutes and approximately $30,000[24] of customer savings. This system will also give near real-time restoration feedback and provide insight into any "nested" outages that may require follow up by crews.

Volt-Var Optimization

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

The VVO system operates by constantly optimizing voltage regulation (voltage regulators, LTCs) and reactive compensation (through switched capacitor banks). The VVO project is expected to reduce customer energy consumption by 2% and is expected to reduce system and circuit peak demand by a similar amount. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills. The Company's overall plan is to install VVO on 100% of the Company's circuits. Therefore, all customers will have the opportunity to achieve the benefits of VVO.

Field Area Network

A field area network ("FAN") is a foundational technology that provides the Company with the communications backbone required to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other functionality does not result in any monetizable benefits. However, the VVO, ADMS, DERMS and SCADA systems cannot provide the benefits identified without a FAN.

[24] Based upon 2018 Berkley Lab Interruption Cost Estimator using Company outage and customer counts. ICE Model estimates savings of $0.05 per minute for a residential outage and $8.53 for small commercial and industrial customers. 87% of the Company's customers are residential (26,500/30,500=0.87). 13% of the Company's customers are commercial/industrial (4,400/30,500=0.13). (25,000*0.87*$0.05)+(25,000*0.13*$8.53)=$28,809.

This project is a continuation of the Company's FAN project that was started in the first phase of grid modernization. The project consists of installing modems connected to an internet service provider vendor's network, including backhaul communications. Redundant fiber connections were completed between the Exeter and Hampton facilities, which house Central Electric Dispatch Services. The Company expects that the deployment of a FAN will continue to follow the same prioritization plan for substation and circuit deployment.

ADMS/DERMS

This project will consist of upgrading the Company's current OMS to an ADMS that will support VVO and unbalanced load flow analysis. In the future the AMDS will also support: distribution system automation, including automated distribution switching and 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, and OMS will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

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 integration of outside data sources such as real-time weather and VVO. The ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner. The ADMS will also provide valuable information during outage events and enhance situational awareness resulting in shorter outage durations.

The Company ADMS system will be implemented with the following functionalities:

- GIS editor to transfer the network model from the GIS to the ADMS on a routine basis as changes to the network topology are made in GIS
- New process to provide ADMS customer load profile and generator output information.
- Verification of network connectivity
- Enhancements of the existing OMS
- Migration from the pre-existing standalone SCADA system to the ADMS SCADA system
- Switch Order Module (manager) and simulation module
- Manual Load Shed and System Power Factor Management
- VVO
- Crew assignments

- Engineering based load flow and circuit analysis tools
- Hardware, software, and training
- Hot standby fault recovery

An ADMS system will need to closely integrate with other enterprise systems to realize its full potential such as the FAN to provide communication to field devices, the installation of field devices that have the ability to be controlled, and a DERMS which provides the monitoring and control of DERs connected to the system.

ADMS is an enabling technology. The ADMS will enable effective VVO, reducing customer energy consumption by 2% and commensurate peak demand reductions. The benefits will accrue directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS will also enable better voltage control for integration of DER and improved reliability through FLISR. The ADMS will serve as a platform for more advanced modules such as a DERMS. DERMS will provide the visibility and control to enable an increased quantity of distributed resources. Quantifiable benefits are shown under the other 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 and network configuration. Additionally, the Company's ADMS will utilize "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

The plan for ADMS includes the implementation of a DERMS. This is an add-on to the ADMS which provides the ability to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, demand response, etc.) including both Company-owned and customer-owned facilities. DERMS will provide the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the utility the ability to manage the impact of DER and operate the system more efficiently.

Mobile Damage Assessment Platform

This project comprises the implementation of a Mobile Damage Assessment Platform to enable 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 allows for faster and more accurate situational awareness during large scale weather events.

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. This translates to an estimated savings of approximately 700,000 customer minutes and over $1,000,000 in customer savings based upon the Berkley ICE Calculator.

DER Mitigations

As the proliferation of DER on electric distribution systems increases to levels approaching that of the local distribution loads, challenges caused by reverse power flow and sustained energization become more prevalent. These challenges include adverse impacts on voltage regulation, short-circuit protection and overvoltage protection.

The project objectives in 2022-2025 are to implement overvoltage protection improvements on the 69 kV side of several distribution substations to mitigate the risk of ground-fault overvoltage resulting from distribution-connected DER sustaining the energization of the 69 kV system after the normal effectively-grounded utility transmission and sub-transmission sources have disconnected in response to line-to-ground short circuits. The implementations include modifications to substation and sub-transmission line surge protection, and the addition of voltage transformers and overvoltage relaying schemes where necessary.

At present, mitigations to accommodate the interconnection of DER are identified during impact studies of individual DER projects, and the associated costs are borne by the specific DER project owner(s) causing the need for those mitigations rather than electric customers in general. That has traditionally worked for typical mitigations to accommodate medium to large DER interconnections, since DER projects of those scale have been able to bear those costs that are directly associated with them. However, the reverse power flow and sustained energization concerns that this project is directed towards are the result of aggregate DER spread across multiple distribution circuits, especially high quantities of residential-scale DER, and “next in queue" residential-scale DER projects are not usually able support the extensive costs for mitigations at substation and sub-transmission levels. This project will remove barriers on substations that have reach or are close to reach saturation for DER interconnections.

AMI Meter Replacements

The Company first installed advanced metering infrastructure on its system over fifteen years ago. The Company's original AMI installation was state of the art when it was installed, but has been outpaced by new technology that can provide more functionality. As such, the Company's 2022-2025 Grid Modernization Plan included an AMI meter replacement plan to transition from its existing TS2 meters to an advanced interval metering functionality that will enable the Company to implement enhanced rate plans, which will provide our customers with the ability to achieve the full benefit of their technology investments or changes in customer user patterns. Benefits to participating customers include lower energy bills. Over time, the impact of this AMI technology is expected to reduce overall market rates for all customers. Additional benefits include lower peak and critical peak energy usage, which can defer investments in equipment; timely and accurate data to support various system, customer, and market facing technologies; and grid facing functions such as distribution management, system planning, and system optimization. Installation of AMI enables improvements in outage monitoring and circuit monitoring due to the increased speed of response from the meters to the head end system.

Due to the discontinuation of the meter technology initially included in Unitil's AMI plan, Company is currently in the process of selecting a vendor to provide replacement meter and communications technology.

Customer Engagement and Experience

This project will strengthen current service offerings, make enhancements to our customer web portal (or Customer Experience Management Solution), and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

This project will design, develop, test and implement a robust, personalized self-service solutions providing our customers with a responsive web experience, mobile application, and tailored, timely and proactive notifications for customers over an extended period estimated to commence in 2024. The project is a foundational element to providing customers with energy information, products and services that align with the Company's mission and strategic customer vision roadmap.

This is a foundational project that enables larger product offerings such as TOU rates and as such quantifiable benefits are difficult to calculate for this stand-alone project. The qualitative benefits include: 1) robust content management tools for web-based forms and customized tools, 2) a configurable enterprise notification platform enables real-time service alerts for outage events, TOU rate conditions, and service appointments (to name a few), 3) a mobile application to improve accessibility and ease of use, and 4) provides a foundational platform that enables strategic enhancements such as predicative analytics and artificial intelligence automation.

Easy to understand web-based tools provide customers with the opportunity to control their energy usage. Proactive alerts and preference-driven notifications provide customers with advance notification of changing circumstances. This project provides the flexibility through personalized products and service offerings, individualized customer communications, customized energy related advice, and personalized billing and payment options that cover the wide range of users. Enhanced customer communications, alerts and consulting advice educates the customer to make decisions that can reduce cost and increase the overall affordability of their service. Personalized rate plans and access to a transactional energy marketplace provide options to the customer to improve their overall value proposition. Active management of peak demand usage reduces transmission and generation costs, defers costly system improvements and allows the system to operate in a more efficient manner. Lower capital expenditures resulting from reduced peak demand improves asset utilization and results in customer bill savings. The customer engagement platform will be a forward looking "one-stop-shop" for everything customers related to the products, services and rate offerings available to them.

Data Sharing Platform

The Company's New Hampshire affiliate is working in collaboration with a broad range of stakeholders to develop the foundational components of an online energy data platform that will be implemented to provide benefits in equal measure to the Company's customers in Massachusetts. Two of these foundational components are at the core of this proposal as required by the enabling statute: (1) suitability for Green Button Alliance approval, and (2) the creation of and adherence to a "logical data model". There are numerous functional use cases of value to interested parties that warrant consideration for inclusion in options for platform design.

Development of the unique functionality necessary to support the specific data and output for all desired outcomes would require an enormous and potentially unrealistic level of up-front design and requirements gathering, likely necessitating a traditional “Waterfall” style software development lifecycle. “Waterfall” projects – where project activities occur in linear, sequential phases – by their nature traditionally incur a much longer time-to-launch trajectory with all of the accompanying cost and obsolescence risks that can follow. In an attempt to avoid this, an “enabling platform” is proposed that securely provides a core set of customer energy usage and billing data points in a standardized data format. The Company refers to this architecture as a “Virtual Energy Data Platform”, the structure of which is depicted in the following figure.

This project will have the following benefits to our customers:

- enable customers to better manage their energy consumption
- lower monthly electric bills
- benefit from new products and services offered
- lower transmission capacity costs
- deferred spending on capacity improvements
- lower GHG emissions
- data to support community aggregation
- DER providers can gain access to a larger consumer market

6.3.2 Proposed Projects for 2025-2029 - Description of Implementation Justification and Expected Benefits

6.3.2.1 ENABLE DER TO PROVIDE GRID SERVICES

Project Summary - Develop and demonstrate a framework to compensate DER for providing locational grid services, including mechanisms to increase the value of DER deployed in EJ communities. This investment area includes three components designed to ensure fair and equitable implementation.

- Grid Service Study (Joint EDC Study) - Engage a third-party consultant to support a study of the value of DER and load flexibility as a locational grid service. Building on work supported by the Mass CEC, the study would establish specific levels of compensation for locational grid services, considering the value they create in either capacity or voltage support use cases, depending on their level of availability and assuming direct utility visibility and control to ensure safe and reliable grid operations. The study would include provisions for the added value dispatchable DER can provide in underserved EJ communities. The study would also recommend process mechanisms to implement compensation framework based on minimizing implementation cost and increasing value to DER facilities. Unitil and the other Massachusetts EDCs are proposing to conduct the study collaboratively with input from stakeholders.

- Grid Service Compensation Fund - Establish a fund to compensate dispatchable DER and flexible loads participating in a program to allow utility dispatch to provide grid services. Dispatchable DER and flexible load with capacity to provide grid services would be eligible for compensation consistent with the recommendations from the Grid Service Study. Operating guidelines would ensure facilities were dispatched by the Company based on mutually agreed upon parameters that ensure no violation of interconnection agreements and provide clarity to customers on the impact to operational flexibility.
- Equitable Transactional Energy Study (Joint EDC Study) - Building upon learnings from the Grid Service Study, the Company proposes a second study to develop recommendations for a more dynamic locational value compensation framework. The study would take into consideration the implication of dispatch large numbers of smaller facilities in a virtual power plant ("VPP") configuration that have the flexibility to choose their level of participation at any point in time. The study would include a framework for dynamic pricing mechanisms to reflect a higher value of DER in underserved EJ communities. The result of the Equitable Transactional Energy Study would inform proposals in the Company's 2030-2034 ESMP.

Payments made to participating FTM DER facilities would be based on the value framework established in the FTM Grid Services Study and the Company would cap total customer payments at $TBD over the ESMP term. Knowledge gained through this effort will inform future efforts to determine the optimal level of incentive to encourage DER participation as grid assets, while minimizing costs to customers. The ability of the Company to implement this program assumes authorization to deploy the DERMS Phase II investment described below.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ TBD	$ TBD	$ TBD	$ TBD	$ TBD	**$ TBD**
O&M Costs (000s)	$ TBD	$ TBD	$ TBD	$ TBD	$ TBD	**$ TBD**
Total Costs (000s)	**$ TBD**	**$ TBD**	**$ TBD**	**$ TBD**	**$ TBD**	**$ TBD**

Table 20 – Proposed Grid Services Spending

Customer Benefits – The need to accommodate the load growth associated with beneficial electrification and further support for DER integration requires expansion of the capacity of the Company's distribution system. This infrastructure deployment will provide the grid flexibility required to ensure all customers have access to the benefits of clean energy. However, the full promise of grid modernization cannot be realized by investments in utility infrastructure alone. Utilizing current and future clean energy DER as a grid asset is a critical component to the total solution, making use of all available resources to optimize the distribution grid for cost-effective clean energy deployment. Together, capacity upgrades supported by DER used to provide grid services ensure all tools in the tools box are utilized to meet the Commonwealth's aggressive clean energy objectives.

Currently, DER facilities are limited in their ability to receive compensation for benefits they may provide a distribution system "value stack" without a mechanism to provide locational grid services. To date, the promise of using dispatchable clean energy resources to create value has been limited to addressing system-wide needs such as ISO-NE peak. System needs, however, are highly locational, varying significantly by substation, feeder and even circuit segment. As a distributed resource, dispatchable DER can address local system needs by providing grid services to address capacity and voltage constraints. For example, if a substation transformer is at risk of an overload in the reverse direction (distribution to transmission) during light load periods, solar can be curtailed or batteries can be charged to alleviate the constraint. Similarly, to reduce line losses and associated carbon emissions, solar or battery inverter settings can be changed to support optimized power flows as a part of a Volt VAR optimization scheme.

The constraint limiting the ability of DER to provide grid services is partially technical. Existing systems and technologies need improvements to identify needs in real time, locate DER available to address the need, dispatch the resource in real time, ensure resource addresses the need once dispatched, and provide tracking of system operations. Assuming all the technology is in place, a mechanism is needed to compensate DER for allowing the utility to dispatch for local real time system conditions.

Determining the proper level of compensation for DER providing grid services is a relatively complex undertaking, involving multiple considerations. The value of DER is critically dependent on its availability. System operators today count on utility owned and maintained infrastructure constantly monitored to ensure availability. A resource that is not owned or maintained by the utility may have lower levels of availability to support the needs of the distribution system because the utility does not have control over the maintenance, operation or operating schedule.

Fully optimizing the safe, reliable, and low-carbon delivery of electricity requires visibility and control of DER by real-time utility system operators as well as operating agreements to ensure consequences in the event a resource is not available when called upon based on contract provisions. Availability concerns diminish with the number of resources under dispatch. In a virtual power plant configuration, if 100 resources are theoretically available to address a local system need, if the utility assumes a certain percentage will be available at the time of the event, the risk is lessened.

In addition to resource availability, the level of value a DER resource can provide is also driven by the need the DER is addressing. Given the local and time-based nature of system need for capacity or voltage support, value is constantly changing. The trade-off between simplicity of incentive design and the accuracy of value determination must be considered.

Finally, the value of DER should take into consideration the added benefits of encouraging clean energy development in EJ communities. The concept of value stacking to include the use of DER as a grid asset can be expanded to include recognition of the incremental economic and societal value of siting solar and other clean energy DER in areas historically disproportionately affected by the health and economic impacts of pollution.

The customer value of this investment is to demonstrate a scalable, cost-effective mechanism to capture the un-realized value of DER to provide locational grid services and transfer that value as incentives for further clean energy deployments, prioritizing economic and health benefits of focusing investments on EJ communities. The results of the learnings gained as a result of this investment will inform implementation on a wider scale, potentially using tariffs or other mechanisms, in the Company's 2030-2034 ESMP.

6.3.2.2 Grid Modernization – ADMS/DERMS

Project Description

The Company proposes to continue the deployment of ADMS and the other functionalities that it supports. In 2025 the Company plans to begin its DERMS implementation with the addition of the DERMS model to its ADMS platform. The Company plans to integrate the FG&E owned DER facilities for the testing of DERMS functionality. It is currently anticipated that DERMS will be available to customers in 2027.

Additionally, in 2026 with the installation of a new AMI system the Company plans evaluate "model-based" VVO to "meter-based" VVO. Meter-based VVO may provide the opportunity to deploy fewer line sensors as metering points and potentially allow for a more accurate model. The speed at which the AMI system is able to provide meter readings to the ADMS system will be a factor in the decision on transitioning to meter-based VVO.

In 2026 the Company plans to complete its implementation of the unbalanced loadflow and short circuit modules. This will fully enable ADMS to perform all FLISR, VVO and other loadflow required functions. Once complete additional devices will get added to these functions as they are deployed.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 150	$ 75	$ 0	$ 0	**$225**
O&M Costs (000s)	$ 0	$ 188	$ 199	$ 211	$ 224	**$822**
Total Costs (000s)	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 1,047**

Table 21 – Proposed ADMS/DERMS Spending

Customer Benefits

ADMS is an enabling technology. The ADMS will enable effective VVO, reducing customer energy consumption by 2% and commensurate peak demand reductions. The benefits will accrue directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS will also enable better voltage control for integration of DER and improved reliability through FLISR. The ADMS will serve as a platform for more advanced modules such as a DERMS. DERMS will provide the visibility and control to enable an increased quantity of distributed resources.

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 and network configuration. Additionally, the Company's ADMS will utilize "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

Based upon recent history, FG&E experiences on average 1.5 circuit level outages per month which averages 2,000 customers. FG&E's average outage duration CAIDI is approximately 80 minutes. It is assumed that SCADA can reduce the length of the outage by 10 minutes (5 minutes at the front end and 5 minutes at the end of the outage). That savings would be 20,000 customer-minutes per circuit level outage or 30,000 customer minutes per month (20,000 customer minutes per outage * 1.5 circuit level outages per month) or 360,000 customer-minutes per year.

DERMS provides the ability to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, demand response, etc.) including both company-owned and customer-owned facilities. DERMS will provide the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the utility the ability manage the impact of DER and operate the system more efficiently.

6.3.2.3 Grid Modernization – VVO

Project Description

The Company proposes to continue the commissioning of VVO as described in the 2022-2025 Grid Modernization Plan. The VVO project will continue to install automated communications and controls on all voltage regulators, capacitor banks, energy measurement devices, as well as substation LTC's. The automation will be enabled through communications to the central ADMS system to optimize system voltage and power factor throughout the distribution system. Between 2025 and 2029, the plan is to enable VVO at seven additional substations.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 4,574	$ 2,875	$ 3,092	$ 2,387	**$12,928**
O&M Costs (000s)	$ 15	$ 20	$ 23	$ 30	$ 33	**$121**
Total Costs (000s)	**$ 15**	**$ 6,620**	**$ 2,898**	**$3,112**	**$2,420**	**$13,049**

Table 22 – Proposed VVO Spending

Customer Benefits

The VVO system operates by constantly optimizing voltage regulation (voltage regulators, LTCs) and reactive compensation (through switched capacitor banks). The VVO project is expected to reduce customer energy consumption by 2% and is expected to reduce system and circuit peak demand by a similar amount. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills. The Company's overall plan is to install VVO on

100% of the Company's circuits. Therefore, all customers will have the opportunity to achieve the benefits of VVO.

Year	Installation	Estimated Annual Energy Delivered (kWh)[25]	Annual Peak Load (MVA)	Estimated Annual Savings ($$)	Estimated Cumulative Annual Savings ($$)	Cumulative Demand Savings (MVA)	Cumulative Energy Savings (kWh)
2025	Townsend Summer ST. Lunenburg West Townsend	177,835,509	59	1,486,029	1,486,029	1.2	3,556,710
2026	Beech St.	39,928,166	12	333,648	1,819,677	1.4	4,355,274
2027	Pleasant St. Princeton Rd.	74,118,366	19	619,348	2,439,025	1.8	5,837,641
2028	Rindge Rd. Canton St. River St.	52,742,273	20	440,725	2,879,750	2.2	6,892,486
2029	Sawyer Passway	38,652,580	13	322,989	3,202,738	2.5	7,665,538

Table 23: Estimate Annual VVO Savings

For this portion of the VVO project, the cumulative annual savings, at the completion of the project, are estimated to be approximately 2.5 MVA in peak demand, approximately 7.900,000 kWh in energy savings and approximately $3.0 million in bill savings. The savings calculated here are estimated annual savings assuming a 2% reduction in energy consumption multiplied by the current distribution and basic service rates. The savings in this chart are cumulative, so in 2026 the annual savings would total $1,819,766 ($1,486,029 + $333,648). The savings flow directly to customers through reductions in their monthly bills.

[25] Estimated Annual Energy Delivered is in 2022 Appendix 1 of the 2022 Grid Modernization Plan Annual report

6.3.2.4 Grid Modernization – Automation

Project Description

The objective of this project is to implement key Automation functionality at the Company's remaining substations and extend monitoring and control out on the distribution system. There are currently reclosers and switches located out on the distribution system that require manual operation. Adding automation control of these devices will reduce the number of truck rolls and reduce outage time through the ability to remotely monitor and control the devices.

This project includes adding Automation to 2 field sites per year.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 100	$ 100	$ 100	$ 100	**$400**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 0**	**$ 100**	**$ 100**	**$ 100**	**$ 100**	**$ 400**

Table 24 – Proposed SCADA Automation Spending

Customer Benefits

In addition to facilitating the ADMS/OMS/VVO and other modernization projects, SCADA monitoring and control at the distribution level is foundational to reducing outage response and restoration times through improved outage awareness, fault location, isolation and system reconfiguration capabilities, both manually or through automation. After implementation, it is estimated that outages originating at SCADA-controlled devices may be reduced by 5 minutes of response time at the front-end and 5 minutes of re-energization time at the back-end of an outage for a total savings of 10 minutes, in addition to the time saved with the ability to transfer load. Based upon an example outage effecting 1,500 customers, this would translate to a savings between 15,000 customer minutes per outage.

The following functionality is intended for the devices where these SCADA additions or modifications are planned:

- Real-time telemetry and historical interval data collection for each recloser, including the following measurements:
    - Voltage
    - Current

- Active and Reactive Power
- Active and Reactive Energy (where required)

- Remote monitoring of live/dead states of circuits
- Remote monitoring and control of included breakers, reclosers, switches, etc.

6.3.2.5 Grid Modernization – FERC Order 2222 Implementation

Project Summary - The goal of FERC Order 2222 is to modernize the electric grid and promote competition in the electric markets by removing the barriers preventing DERs from entering the market. The Order allows DERs to participate in the wholesale markets in the same manner that traditional capacity resources participate. This opens up the wholesale market to new sources of energy and grid services.

The Company recognizes that the final FERC 2222 guidelines are not yet approved, but anticipates modifications to software, control systems, other system upgrades may be required within the timeframe of this plan.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$ 0**
O&M Costs (000s)	$ 150	$ 150	$ 50	$ 50	$ 50	**$ 450**
Total Costs (000s)	**$ 150**	**$ 150**	**$ 50**	**$ 50**	**$ 50**	**$ 450**

Table 25 – Proposed FERC 2222 Spending

Customer Benefits - FERC Order 2222 will help to facilitate competition in the electric markets by removing barriers preventing DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators. Over the last few years, DERs have become increasingly popular and desire to enter the wholesale marketplace to compete alongside traditional sources. DERs have the ability to reduce capacity constraints, integrate and increased amount of renewable energy resources, reduce GHG emissions, support the State energy policy, defer distribution investment, and allow customers take control of their own energy future.

6.3.2.6 Grid Modernization – Cyber Security

Operations Technology Cyber Security Enhancements

As Unitil upgrades its infrastructure, incorporates new technologies, and brings together Operational Technology and Information Technology networks, Operational Technology and Industrial Control Systems must be maintained and protected within modern, heterogeneous network environments.

In the next five years, the goal is to implement software solutions to provide improved visibility and actionable data for the many Unitil control system implementations, while simultaneously developing policies and procedures to effectively manage this work. The primary objective is to identify and catalog all assets in the Operational Technology environments, as well as any risks associated with them, and eliminate or mitigate those risks. Doing so will put Unitil in a better position to identify threats, both cyber and operational, such as:

- Cyberattacks (E.g. Denial of Service, Ransomware)
- Unauthorized network connections, communications
- Suspicious user behavior or policy changes
- Device malfunction or misconfiguration
- New and unresponsive assets
- Corrupted messages
- Unauthorized firmware downloads
- Insecure protocols
- Default credentials and insecure authentications
- Logic changes

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$21	$25	$28	$28	$28	**$130**
O&M Costs (000s)	$13	$13	$13	$14	$15	**$68**
Total Costs (000s)	**$34**	**$38**	**$41**	**$42**	**$43**	**$197**

Table 26 – Cybersecurity Spending

Information Technology Corporate Cyber Security Enhancements

The changing threat landscape, regulatory requirements, technology advancements and more in-depth assessment by cyber security insurance providers fuels the need to add new capabilities to Unitil’s cyber defense toolbox.

New technology and innovation by nation-state adversaries and criminal enterprises has resulted in more diffuse, more sophisticated, and more dangerous cyber threats than ever before. Staying ahead of these advances requires that Unitil regularly re-assess security tools and deploy cutting-edge solutions tailored to our environment and risks.

In the next five years, Unitil plans to investigate and implement several upgraded programs and technologies to address these risks and strengthen our security posture. Projects include:

- Security Information and Event Management (SIEM) and Security Orchestration, Automation and Response (SOAR)
- Zero-Trust Architecture
- Privileged Access Management
- Network Access Control
- Static Code Analysis

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$84	$95	$70	$70	$70	**$389**
O&M Costs (000s)	$7	$7	$7	$7	$7	**$35**
Total Costs (000s)	**$91**	**$102**	**$77**	**$77**	**$77**	**$424**

Table 27 – Proposed Information Technology Cyber Security Spending

Customer Benefits

Cyber security of the system is of critical importance to the safety and reliability of the electric grid. More expansive deployment of technology and integration of Company networks with other systems increases the exposure to cyber security risks. Illustrative examples of those risks include direct control of field devices by unauthorized access or an altering of real-time information from the field to the central office resulting in an inaccurate evaluation of the current status of the grid. The reliable function of the Company's control systems (i.e. SCADA, DERMS, ADMS) is critical to public safety and reliability of the grid. Customers need to have confidence that the Company's computer networks are resilient against cyber-attacks. Data security and customer privacy must be carefully integrated into existing operational practices.

6.3.2.7 ESMP Program Administration

The administration of this proposed ESMP will be a considerable undertaking for the Company. At this point, the Company is proposing to implement this program primarily with internal resources to control the costs to customers. The funding shown below will be used for stakeholder outreach activities and measurement and verification (similar to grid modernization).

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$0	$0	$0	$0	$0	**$0**
O&M Costs (000s)	$75	$75	$75	$75	$75	**$375**
Total Costs (000s)	**$75**	**$75**	**$75**	**$75**	**$75**	**$375**

Table 28 – ESMP Program Administration

6.4 10-YEAR PROJECTS

The electric system serves approximately 30,500 customers with an anticipated design peak load of 105.3 MW in 2025, increasing to 118.5 MW in 2034. This increase is predominantly due to proposed large customer load (approximately 3 MW) as well as forecasted EV and electrification load. As part of the Company's traditional electric system and distribution system planning efforts and additional review due to the additional EV and electrification load the electric system was evaluated at these ten year load levels.

The ten year load forecasts and planning efforts are updated and performed annually to identify project need and timing. The following subsections detail the system constraints and significant projects proposed as a result of the ten year study process.

6.4.1 Identified Constraints

The following summarizes the system deficiencies driving improvement proposals during the ten year study period, with the load level and projected year in which they first occur. The table is sorted by year. The system constraint is listed in the year when it first violates planning criteria.

Year	System Constraint	Circumstances
2025	Lunenburg S/S – 13.8kV Bus Regulators – Loaded Above Normal Rating	Basecase
2026	Lunenburg S/S – 31T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
2030	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
2034	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1

Table 29 – System Constraints 2025-2034

6.4.2 Lunenburg Substation Capacity Additions - 2026

To address capacity constraints at Lunenburg substation through 2030, the Company plans to increase the capacity of Lunenburg substation by installing a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC. This will require the expansion of the Lunenburg substation. The expanded substation will be constructed to accommodate two 13.8 kV buses with three outgoing distribution circuit terminals per bus.

For the initial construction the new transformer will supply one 13.8 kV bus and will supply circuits 30W30 and 30W32 (new circuit) with the existing 10.5MVA supplying the other 13.8kV bus and circuit 30W31 and 30W33 (new circuit).

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 4,400	$ 4,700	$ 0	$ 0	$ 0	**$9,100**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 4,400**	**$ 4,700**	**$ 0**	**$ 0**	**$ 0**	**$9,100**

Table 30 – Proposed Lunenburg Substation Spending

This project is currently in the design phase with an expected completion date on 2026. Once complete this project is expected to address equipment loading associated with Lunenburg until approximately 2040. This project does not address loading or voltage constraints associated with the 30W30 distribution circuit, Flagg Pond substation, the 08 line or the 09 line.

Additional consideration and evaluation should be performed to determine if dual high-side (115kVx69kV) voltage transformers should be purchased as the area of Lunenburg substation has been identified as a future 115kV substation location.

Loading on this equipment will continued to be reviewed on an annual basis and as needed upon new customer inquiries. Replacement timing of the existing 10.5MVA transformer replacement and population of additional circuit positions will depend upon when loading on the substation no longer meets planning criteria. proposed as planning criteria is expected to violate.

The capacity additions at Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

6.4.2.1 Description – Capacity and Reliability Needs

Based on 2050 load forecasts it is expected that the Lunenburg substation could be loaded to approximately 41MW by 2050. Two 30MVA transformers will provide sufficient capacity for the area beyond 2050 and also allow for the restoration of all load following a substation transformer outage without the need for the installation of a mobile substation and/or spare transformer.

Constructing the substation to accommodate four additional circuit positions over what exists today will provide sufficient capacity when populated to serve the area with traditional distribution equipment and provide sufficient capacity to allow for restoration switching for mainline faults.

6.4.2.2 Non-Wire Alternatives

According to the Company's Project Evaluation Procedure, a project of this scale/cost would typically necessitate the review of non-traditional alternatives if the constraint allowed for construction to start three to five years in the future. However, due to large forecasted customer load addition(s) this project is required prior to the three-year construction start threshold, and as such only traditional alternatives were considered as options to address the identified constraints.

6.4.2.3 Traditional Alternatives

Due to the need date of the project and proposed location of the load, only variations of the proposed project were evaluated as alternatives to this constraint. These variations were all anticipated to be more-costly than the proposed option.

6.4.2.4 Alternative cost allocation approaches to interconnect battery storage projects – exploration of different approaches – pros and cons

This project is driven by a large customer spot load three years in the future. Therefore, in line with the Company's Project Evaluation Procedure, alternate approaches to install battery storage were not explored for this project.

6.4.2.5 Equity and EJ outreach

The location of this project is not located in an EJ community. Stakeholder outreach will be tailored to the location of the project.

6.4.3 New South Lunenburg Substation - 2030

To address 08 Line, 09 Line and Lunenburg substation capacity constraints beyond 2030 the Company is in the early stages of exploring the feasibility of constructing a new 115kV or 69kV substation in southern Lunenburg. This project will require the purchase of a new plot of land in the vicinity of the existing National Grid right-of-way in southern Lunenburg near Leominster-Shirley Road. National Grid will tap the existing (or future upgraded) transmission system in the area to supply Unitil's new substation.

The proposed substation will consist of a 115kV, four position (two incoming transmission lines, two outgoing transformer taps) ring bus, two 30MVA (or larger), 115kVx69kV to 13.8kV transformers with LTCs, two 13.8 kV buses and six 13.8kV circuit positions. Three circuit positions will be populated and placed in-service when the substation is initially constructed with three circuit positions remaining vacant for future use.

Dual 115kVx69kV transformers are currently being considered at this location as there are future plans for the existing 69kV lines in the area to be upgraded to 115kV.

Year	2025	2026	2027	2028	2029	Total Project Cost
Capital Costs (000s)	$1,750	$1,250	$7,000	$8,000	$2,500	**$20,500**
O&M Costs (000s)	n/a	$ 0	n/a	n/a	n/a	**n/a**
Total Costs (000s)	**$1,750**	**$1,250**	**$7,000**	**$8,000**	**$2,500**	**$20,500**

Table 31 – Proposed South Lunenburg Substation Spending

The Company is currently investigating available land in the area and has started initial discussions with National Grid regarding the transmission supply to the proposed substation. It is currently anticipated that the Company could have this substation in service in the 2029 timeframe with land procurement and detailed design work beginning in 2024.

This project is expected to remove approximately 10MW from the "greater" electric system and will defer the need to address Flagg Pond 4T1 and 4T2 transformer loading as well as 01, 02, 08, 09 line loading concerns to the following years. This project is anticipated to address loading and voltage constraints associated with the Lunenburg 30W30 distribution circuit and improve reliability to the customers in served by the existing Lunenburg substation.

Year	System Constraint	Circumstances
2037	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1
2040	01 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 02 Line from Flagg Pond S/S to Summer Street S/S
	02 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 01 Line from Flagg Pond S/S to Summer Street S/S
2043	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend

Table 32 – Constraints Alleviated by South Lunenburg Substation

This project creates a new system supply into the Company's distribution system. The capacity additions at the New South Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

6.4.3.1 Description – Capacity and Reliability Needs

Based on 2050 load forecasts it is expected that the new South Lunenburg substation will be able to support load in the southern Lunenburg area until 2050 and beyond. It will have sufficient capacity to provide distribution circuit back-up to other circuits in the Lunenburg area. Additionally, the two 30MVA transformers will provide sufficient capacity for the area well beyond 2050 and also allow for the restoration of load following a substation transformer outage without the need for a 115kV to 13.8kV mobile transformer or the immediate installation of a spare transformer.

This project is also expected to improve reliability to the customers in served by the existing Lunenburg 30W30 circuit as well as circuit 30W31. Circuit 30W30 is historically one of the Company's worst performing circuits. This project will offload circuit 30W30, greatly reducing customer exposer as well as providing distribution circuit redundancy to the Lunenburg area. This project will also offer the opportunity to reconfigure circuits 30W31 to the 30W30 circuit position, reducing customer exposure on circuit 30W31.

6.4.3.2 Non-Traditional Alternatives

According to the Company's Project Evaluation Procedure, a project of this scale/cost would typically necessitate the review of non-traditional alternatives if the constraint allowed for construction to start three to five years in the future. However, due the project procurement, engineering and construction timeline of this project and its traditional alternatives, non-traditional alternatives were not considered. This project is currently under development and is expected begin prior to the three years typically needed to evaluate, install and confirm performance of a non-traditional alternative.

6.4.3.3 Traditional Alternatives

The following group of traditional projects were considered as an alternative to the construction of the proposed South Lunenburg substation. All projects listed below would be required to address the identified constraints.

<u>08 and 09 Line Capacity Additions -2030</u>

Reconductor the 08 and 09 lines from Pleasant Street substation to the Lunenburg tap with 795 ACSR conductor (or larger).

These lines would be constructed in a "double-circuit" configuration to accommodate future 115kV transmission lines (one each pole) for future lines between Flagg Pond and Lunenburg substations in the future.

Year	2028	2029	2030	Total Project Cost
Capital Costs (000s)	$1,100	$4,950	$4,950	**$11,000**
O&M Costs (000s)	n/a	n/a	n/a	**n/a**
Total Costs (000s)	$1,100	$4,950	$4,950	**$11,000**

Table 33 – Estimated 08/09 Line Reconductoring

Flagg Pond Substation Capacity Additions - 2034

Installation of additional capacity at Flagg Pond. This would include the installation of an additional transformer or the replacement of the existing Flagg Pond transformers. At this time, it would be recommended that the existing transformers (including the system spare transformer) be replaced with new 200MVA units with LTCs. It is anticipated that voltage regulations will be required at Flagg Pond prior to 2050 and the additional capacity will address other future loading constraints. This project will also include the upgrade of the 69kV bus and breakers to accommodate the additional transformer and line capacity.

Year	2032	2033	2034	Total Project Cost
Capital Costs (000s)	$4,875	$9,750	$4,875	**$19,500**
O&M Costs (000s)	n/a	n/a	n/a	**n/a**
Total Costs (000s)	$4,875	$9,750	$4,875	**$19,500**

Table 34 – Estimated Flagg Pond Capacity Additions

Total Alternative Capital Costs (000's):

Year	2028	2029	2030	2031	2032	2033	2034	Total Project Cost
Flagg Pond Capacity Additions	n/a	n/a	n/a	n/a	$4,875	$9,750	$4,875	**$19,500**
08 & 09 Line Capacity Additions	$1,100	$4,950	$4,950	n/a	n/a	n/a	n/a	**$11,000**
Total Costs	$1,100	$4,950	$4,950	n/a	$4,875	$9,750	$4,875	**$31,500**

Table 35 – Estimated 08/09 Line and Flagg Pond Spending

6.4.3.4 Alternative cost allocation approaches to interconnect battery storage projects – exploration of different approaches – pros and cons

Construction for this project is scheduled to begin within a five year timeframe. Therefore, in line with the Company's Project Evaluation Procedure, alternate approaches to install battery storage were not explored for this project.

6.4.3.5 Equity and EJ outreach

The location of this project is not located in an EJ community. Stakeholder outreach will be tailored to the location of the project.

6.5 NEW CLEAN ENERGY CUSTOMER SOLUTIONS

DER penetration across the electric system continues to increase at a rapid pace. DERs are electricity producing resources or controllable loads connected to a distribution system, including but not limited to roof top solar, wind, CHP, energy storage, small gas-powered backup generators, electric vehicles, heat pumps and controllable loads. Behind the meter DER such as roof top solar is the largest application of DER technology across Unitil's service territory. Inefficient performance increases the risk profile for these DERs creating the need to optimize the system to ensure reliability. Hosting capacity and locational value analysis support the interconnection of DERs which provide an additional means of support for an optimized system.

The tables below provide the 2050 peak load and DER forecast with and without the system modifications as described throughout this report.

Substation	Transformer	No Changes				
		Nameplate (MVA)	2050 Peak Load (MW)	% Loaded of Nameplate	DER (MW)	% DER of Nameplate
Beech Street	1T1	22	47.7	213%	31.6	141%
Canton Street	11T1	14	26.2	187%	17.4	124%
Lunenburg	30T1	10.5	36.3	346%	24.1	229%
	30T2	n/a	n/a	n/a	n/a	21.7
Pleasant Street	31T1	14	36.8	263%	24.4	174%
Princeton Road	50T2	20	15.7	79%	10.4	52%
	50T3	20	47.9	239%	31.8	159%
River Street	25T1	14	26.3	188%	17.4	125%
Sawyer Passway	22T1	20	13.6	68%	9.0	45%
	22T2	20	9.8	49%	6.5	32%
Summer Street	40T1	35	59.2	169%	39.3	112%
	40T2	n/a	n/a	n/a	n/a	22.2
Townsend	15T1	10.5	33.3	317%	22.1	211%
	15T2	n/a	n/a	n/a	n/a	16.7
West Townsend	39T1	10.5	29.7	283%	19.7	188%
South Lunenburg	T1	n/a	n/a	n/a	n/a	11.8
	T2	n/a	n/a	n/a	n/a	11.8
Beech Street Tap	T1	n/a	n/a	n/a	n/a	17.5
	T2	n/a	n/a	n/a	n/a	10.5
Rindge Road	T1	n/a	n/a	n/a	n/a	n/a
Ashby	T1	n/a	n/a	n/a	n/a	12.0
	T2	n/a	n/a	n/a	n/a	16.9
Flagg Pond	4T1	100	194.6	195%	129.1	129%
	4T2	100	187.9	188%	124.6	125%
Lunenburg/Summer Supply	T1	n/a	n/a	n/a	n/a	n/a
	T2	n/a	n/a	n/a	n/a	n/a

Table 36 – 2050 Peak Load and DER Forecast – Without Proposed System Modifications

Substation	Transformer	2050 Proposed Changes				
		Nameplate (MVA)	2050 Peak Load (MW)	% Loaded of Nameplate	DER (MW)	% DER of Nameplate
Beech Street	1T1	22	16.2	72%	10.7	48%
Canton Street	11T1	30	21.0	70%	13.9	46%
Lunenburg	30T1	30	18.8	63%	12.5	42%
	30T2	30	22.8	76%	15.1	50%
Pleasant Street	31T1	30	23.6	79%	15.6	52%
Princeton Road	50T2	20	15.7	79%	10.4	52%
	50T3	30	24.0	80%	15.9	53%
River Street	25T1	30	16.6	55%	11.0	37%
Sawyer Passway	22T1	20	14.3	71%	9.5	47%
	22T2	20	10.3	51%	6.8	34%
Summer Street	40T1	30	23.3	78%	15.5	52%
	40T2	30	23.3	78%	15.5	52%
Townsend	15T1	30	17.5	58%	11.6	39%
	15T2	30	17.5	58%	11.6	39%
West Townsend	39T1	30	12.0	40%	8.0	27%
South Lunenburg	T1	30	12.4	41%	8.2	27%
	T2	30	12.4	41%	8.2	27%
Beech Street Tap	T1	30	18.4	61%	12.2	41%
	T2	30	11.0	37%	7.3	24%
Rindge Road	T1	30	21.3	71%	14.1	47%
Ashby	T1	30	12.6	42%	8.4	28%
	T2	30	17.7	59%	11.7	39%
Flagg Pond	4T1	200	109.5	55%	72.7	36%
	4T2	200	105.7	53%	70.1	35%
Lunenburg/Summer Supply	T1	200	83.6	42%	55.5	28%
	T2	200	83.6	42%	55.5	28%

Table 37 – 2050 Peak Load and DER Forecast – with Proposed System Modifications

The proposed system modifications will increase the total system hosting capacity by approximately 250%.

Unitil implements a standard criteria to evaluate Non-Wire Alternatives ("NWAs") to ensure the Company is considering alternatives to traditional utility investment. The Company's Project Evaluation Procedure (No. PR-DT-DS-11 Revision 1, dated 7/2/2021), provides a consistent approach and procedure for project evaluation and establishes thresholds in which the Company reviews non-wires alternative projects and performs detailed cost/benefit analyses that include reliability, environmental and economic impacts.

A good example of a recent NWA is the Company's Townsend Energy Storage System. The Company owns and operates a 2 MW/4MWh utility scale energy storage system located at Townsend substation designed to defer the need for a costly substation expansion. The energy storage system has the ability to serve over 1,300 homes for over two hours. This energy storage system is designed to reduce peak loading on the substation equipment, as well as provide voltage regulation and frequency regulation to the market. This is a significant size energy storage device measuring over 2% of the Company's system peak. The Company continues to evaluate opportunities to install additional utility scale energy storage in areas of the system that may benefit from the additional capacity.

The clean energy programs offered through the Mass Save 3- Year Plan include: energy efficiency, demand response (including battery storage), electric heat pumps and electric vehicles. Energy efficiency is used as an NWA to defer investment, as described in the Company's distribution planning guide. Through the Mass Save 3-Year Plans, targeted EE and load curtailment projects are reviewed for any major piece of equipment that is expected to exceed either of the following:

- Normal/Basecase Conditions - 80% of its seasonal normal rating during the first five years of the study period and 90% of its seasonal normal rating in year five of the study period.
- Planned Contingency Conditions - 100% of its seasonal normal rating during the first five years of the study period and 110% of its seasonal normal rating in year five of the study period or 80% of its seasonal LTE rating during the first five years of the study period and 90% of its seasonal LTE rating in year five of the study period.

To support the development of NWAs and enable DER to provide grid services, the Company has proposed the Grid Services Study (Joint EDC Proposal), Grid Service Compensation Fund, and the Equitable Transactional Energy Study (Joint EDC Study) (reference Section 6.3.2.1).

The Company's AMI system has been providing benefits to our customers for more than a decade. AMI provides the basis for interval metering which supports the rate programs to support demand response programs and further integration of renewable resources. The Metering Data Management system provides the platform for sharing data with customers and interested third parties and will enable time-based rates. Interval metering allows customers to manage their own risks and benefits. Advanced metering functionality is proven and a required component to develop the modern grid as an enabling platform.

Rate design is an important tool to shave peak loads. The Company has implemented TOU rates for electric vehicles and has the capability to develop other TOU programs. TOU rates benefit the customer as well as the system. Consumers with TOU rates and the ability and willingness to shift some usage to off peak hours not only benefit the customer through reduced rates, but it also benefits the system by reducing peak demand and deferring increases in capacity. TOU rates support demand response programs and other energy management activities that rely on automation to reduce their electricity consumption at peak times.

7 5-YEAR ELECTRIC SECTOR MODERNIZATION PLAN

The Company has taken a practical approach to the 5- and 10-year spending plans associated with this ESMP. This Plan has been developed based upon the Company's relative size and customer demographics. The Company will continue to review and improve on this Plan.

7.1 INVESTMENT SUMMARY 5-YEAR CHART – BASE RELIABILITY, EXISTING PROGRAMS (E.G., CIP, EV, EE, GRIDMOD, AMI), AND NEW PROPOSALS. IMPACT ON GHG EMISSION REDUCTIONS

The spending shown below considers existing capital and operating expense spending programs (base budget), pre-authorized programs (i.e. EE, grid modernization, and electric vehicles), and newly proposed spending (i.e. capacity, extended grid modernization, reliability and resiliency and customer facing programs). This spending plan contemplates a pre-authorization by the Department similar to the approach taken in Grid Modernization.

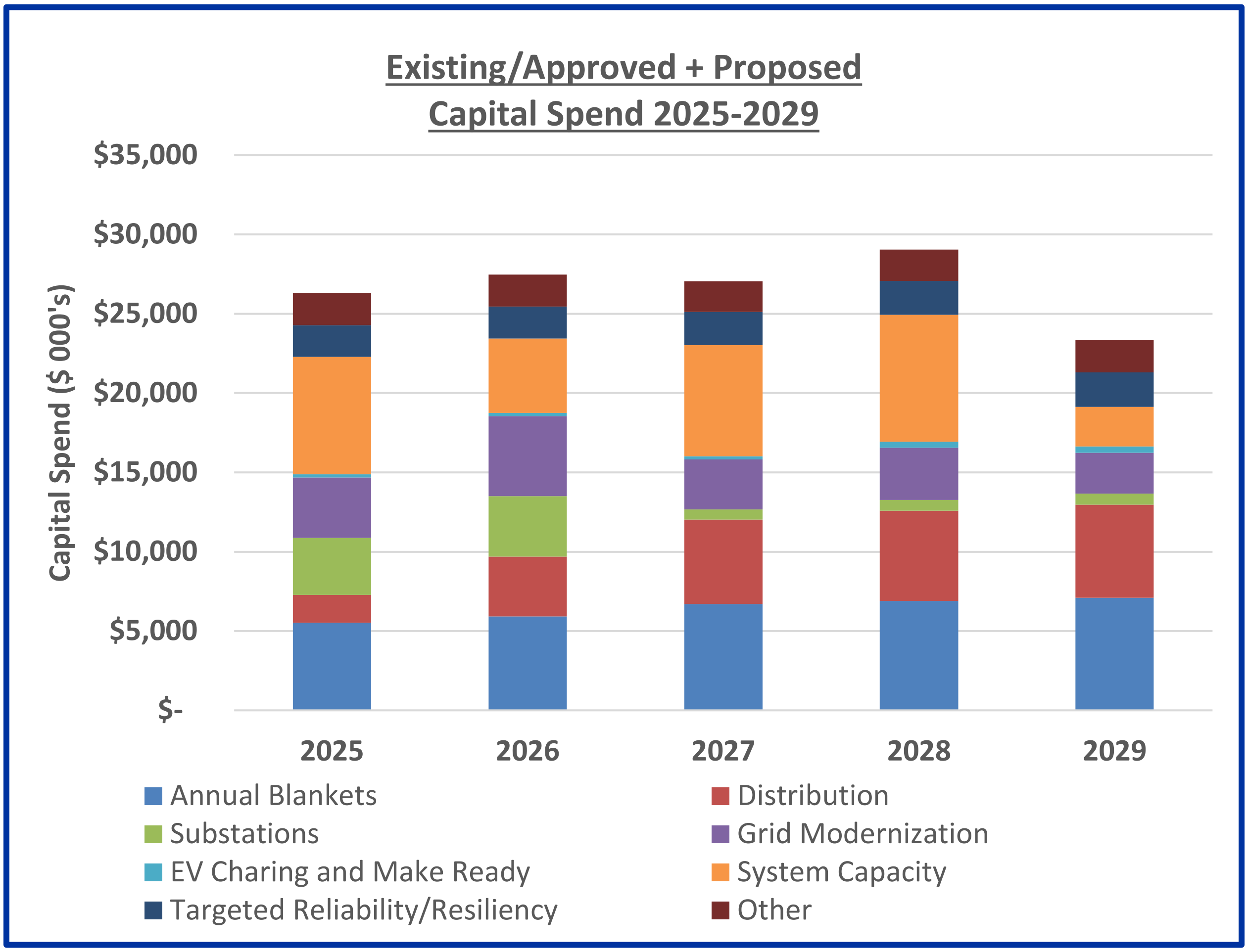

Figure 15 – 2025-2029 Capital Spending (Existing and Proposed)

The capital budget has been categorized as follows:

Existing Capital Spending:

- Annual Blankets - This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) and cannot be individually anticipated at budget time. As we previously explained, these projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consist of new customer requests for service including new services and small line extensions; outdoor lighting includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration includes capital repairs and replacements required to restore service to customers following storms or outages; billable work includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, transformer and meters are for the purchase of transformers and meters.

- Distribution - These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our agreements with Verizon or other pole attachees; highway projects are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $30,000 that are identified by engineering or others that are needed to meet service obligations.
- Substations - These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.
- Reliability/Resiliency – These are projects designed and justified specifically to address reliability and resiliency concerns across the system. Projects are developed as part of the annual reliability planning process.
- Others - Communications includes additions and replacements of communication-related equipment such as Supervisory Control and Data Acquisition (SCADA), radio systems for field communications, and communication equipment for the Company's Advanced Metering Infrastructure (AMI) system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices.
- Common - Projects that can be allocated to both electric and gas are identified as common projects. These projects include office furniture and office equipment, including normal additions and replacements; and structures includes upgrades and improvements to the Company's buildings, including the Company's operations center building. Common facilities have been apportioned to electric or gas based on an allocation provided by Accounting. In general, these facilities represent only a small portion of the overall budget.

Pre-Authorized Capital Spending

- Grid Modernization - These are individually-authorized projects that have received pre-authorization under the Company's filed Grid Modernization Plan.
- EV Charging and Make Ready – This is the pre-approved capital spending for EV charging make ready projects.

Proposed Capital Spending

- Grid Modernization - These are new grid modernization projects proposed as part of this ESMP. These projects may be extensions or acceleration of existing grid modernization projects or programs. These projects include:
    - ADMS/DERMS - The Company proposes to continue the deployment of ADMS and the other functionalities that it supports. In 2025 the Company plans to begin its DERMS implementation with the addition of the DERMS model to its ADMS platform. The Company plans to integrate the FG&E owned DER facilities for the testing of DERMS functionality. In 2026 the Company plans to complete its implementation of the unbalanced loadflow and short circuit modules. This will fully enable ADMS to perform all FLISR, VVO and other loadflow required functions. It is currently anticipated that DERMS will be available to customers in 2027.
    - VVO - The Company proposes to continue the commissioning of VVO as described in the 2022-2025 Grid Modernization Plan. The VVO project will continue to install automated communications and controls on all voltage regulators, capacitor banks, energy measurement devices, as well as substation LTC's. The automation will be enabled through communications to the central ADMS system to optimize system voltage and power factor throughout the distribution system. Between 2025 and 2029, the plan is to enable VVO at seven additional substations.
    - Automation - The objective of this project is to implement key Automation functionality at the Company's remaining substations and extend monitoring and control out on the distribution system. There are currently reclosers and switches located out on the distribution system that require manual operation. Adding automation control of these devices will reduce the number of truck rolls and reduce outage time through the ability to remotely monitor and control the devices.
    - FERC Order 2222 Implementation - The goal of FERC Order 2222 is to modernize the electric grid and promote competition in the electric markets by removing the

barriers preventing DERs from entering the market. The Order allows DERs to participate in the wholesale markets in the same manner that traditional capacity resources participate. This opens up the wholesale market to new sources of energy and grid services. The Company recognizes that the final FERC 2222 guidelines are not yet approved, but anticipates modifications to software, control systems, other system upgrades may be required within the timeframe of this plan.

- Cyber Security - The goal is to implement software solutions to provide improved visibility and actionable data for the many Unitil control system implementations, while simultaneously developing policies and procedures to effectively manage this work. The primary objective is to identify and catalog all assets in the Operational Technology environments, as well as any risks associated with them, and eliminate or mitigate those risks. In the next five years, Unitil plans to investigate and implement several upgraded programs and technologies to address these risks and strengthen our security posture.

- Capacity Projects
    - Lunenburg Substation - The capacity additions at Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.
    - South Lunenburg Substation - This project creates a new system supply into the Company's distribution system. The capacity additions at the New South Lunenburg substation will increase the reliability of this portion of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The amount of the capacity addition has been informed by the Company's demand assessment described in Section 8. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

- EV Charging and Make Ready – This is a proposed extension of the EV make ready program.
- Targeted Reliability/Resiliency – The Company is proposing to increase spending on its targeted spacer cable and undergrounding projects in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist.

In addition to the capital investments, the Company has provided existing, previously authorized and proposed operations and maintenance expense spending.

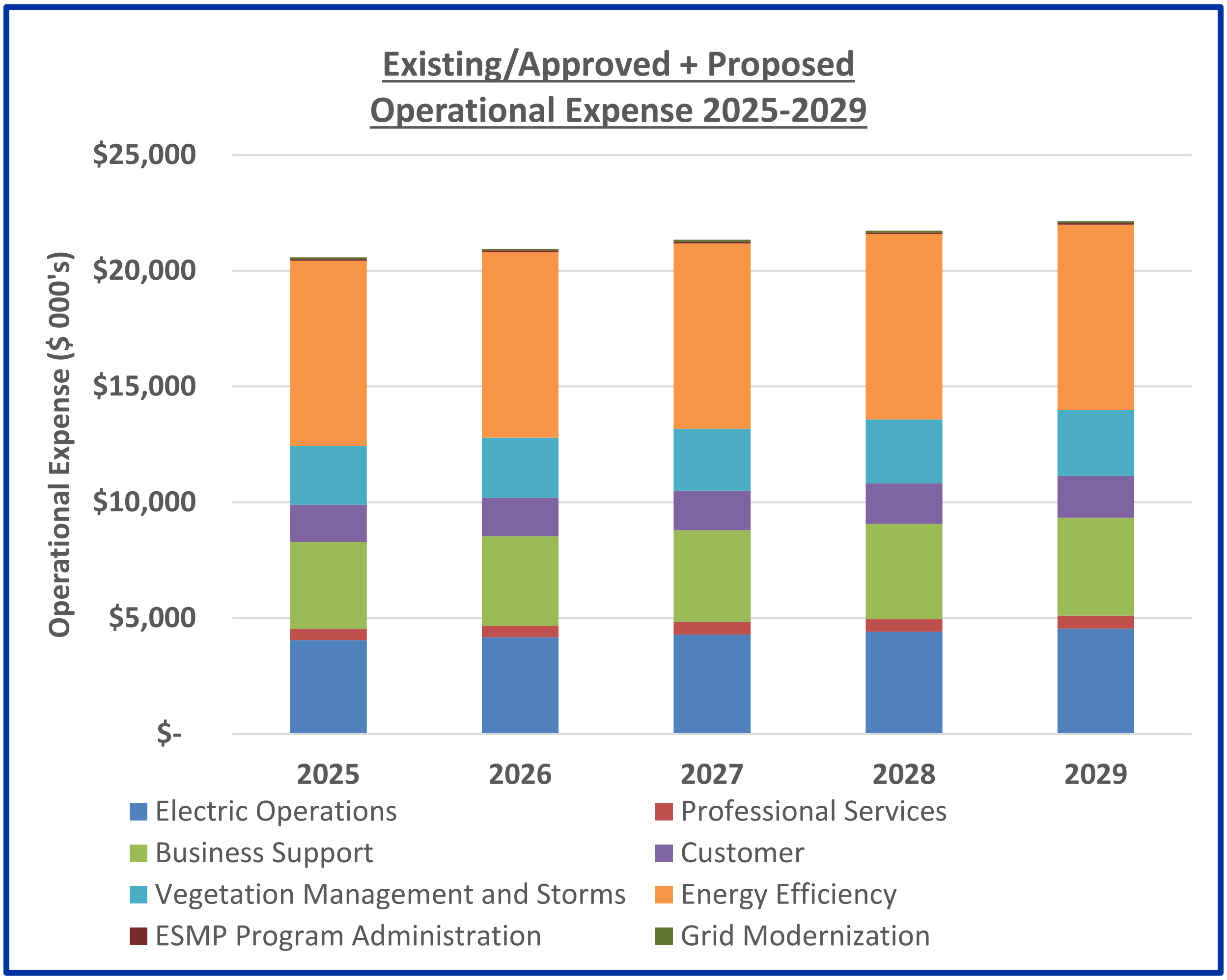

Figure 16 – 2025-2029 Operating Expense Spending (Existing and Proposed)

The operating expense budget has been categorized as follows[26]:

Existing Operating Expense

- Electric Operations – Electric operations covers the operations and maintenance of the electric system including by not limited to: distribution maintenance, substation maintenance, street light maintenance, underground maintenance, metering, field services as well as the field and local supervisory labor associated with these activities.
- Professional Services – These are services the Company hires out when additional resources are needed or specialized skills are needed.
- Business Support – Business support includes the functions related to supporting the business, such as, billing, postage, insurance, customer outreach, banking fees, software fees, regulatory assessments, telecom and service company allocations.
- Customer – Customer includes functions such as, costs associated with credit and collections and the provisions for customer bad debt.
- Vegetation Management and Storms – Vegetation Management activities include the cycle pruning, hazard trees and storm resiliency program maintenance activities.

Previously Approved Operating Expense

- Energy Efficiency – This category represents the program administration fees associated with the Company's EE program through Mass Save.
- Electric Vehicles – Electric vehicle expense includes the Department approved customer refund and reimbursements for residential EV charging facilities.
- Grid Modernization – Grid Modernization expense includes the Department approved grid modernization expenses.

Proposed new Operating Expense

- Energy Efficiency – This category represents new program administration fees associated with the Company's EE program through Mass Save past the 2024 timeframe.
- Electric Vehicles – Electric vehicle expense includes proposed new expenses not previously authorized by the Department for the extension of customer refund and reimbursements for residential EV charging facilities.

[26] Note the operating expense budget shown does not include the power purchase expense items.

- Grid Modernization – Grid Modernization expense includes proposed new grid modernization expenses not previously approved by the Department for the extension of existing as well as proposed grid modernization projects.
- ESMP Program Administration – The administration of this plan will require funding to be successful. This funding would be used for stakeholder outreach and any measurement and verification efforts (similar to grid modernization).

7.1.1 Alternatives to proposed investments – Estimates of Impact of Investment Plan Alternatives

As described in the preceding sections, the Company has developed this Plan in response to the forecasted increase in customer loads, DER interconnections, electric vehicles, electrification of residential heating and other projects. The Company's detailed planning process identifies system constraints and develops alternatives for those investments. This detailed process in conjunction with the Company's planning criteria, ensures the safe, reliable, resilient and affordable operation of the electric system while working towards helping the Commonwealth realize its GHG emission targets. The Company must complete the projects associated with capacity expansion in the next several years to ensure sufficient capacity to serve new loads.

The Company is proposing to increase the capacity of Lunenburg Substation and the addition of a new South Lunenburg Substation as part of the Plan. These projects will increase the reliability of the system though providing additional capacity to serve the load as well as provide the opportunity for circuit modifications to reduce the overall size and customer exposure due to the reduced customer counts. The project will increase the hosting capacity of the overall area as it will reduce the loading on the 08 and 09 Lines as well as Flagg Pond Substation. This ensures the capacity will be available to support electrification of transportation and building sectors as well as increase the hosting capacity for the integration of new DERs such as PV, ESS, wind or other.

The Company is proposing to continue with grid modernization investments. When the Company filed its initial grid modernization plan in 2015, it proposed a comprehensive deployment of grid modernization technology across the service territory so all customers could benefit from these investments as opposed to those customers served from individual circuits.

The Company believes that DERs that are reliable and available to respond to electric system needs can be beneficial to the safe and reliable operation of the electric system. However, the

Company is currently not able to compensate customers for this type of use. The Company along with the other EDCs, are proposing studies and a compensation fund to develop and enable a compensation system for DER providing grid services. Compensation mechanisms along with the tools and information required to integrate these DERs into the real-time operation of the electric system are important next steps in the evolution of the distribution system.

7.1.2 Alternative approaches to financing

The Company's proposed projects in this Plan fall into two different categories: 1) grid modernization and 2) capacity expansion for load. The grid modernization projects are predominantly a continuation of the existing grid modernization projects currently being implemented by the Company. The capacity projects are focused on increasing capacity for load, but these projects will also inherently increase the hosting capacity of the distribution system.

The Company has experienced a high level of penetration with respect to DERs (specifically rooftop solar) interconnections. However, the quantity and size of the DER interconnections have not driven the need for group studies or the implementation of Capital Investment Project ("CIP") project funding.

In the future, should the Company find the need to conduct a group study that results in significant capital investment, the Company proposes to apply the CIP approach approved by the Department in in D.P.U. 20-75-B. Any new CIP proposal would be evaluated on a case-by-case basis and submitted to the Department for review and approval.

7.1.3 Customer benefits

Massachusetts General Laws Chapter 164 Section 92B – 92C requires that the Company's ESMP be designed to proactively upgrade the distribution and, where applicable, transmission systems to:

- improve grid reliability, communications and resiliency;
- enable increased, timely adoption of renewable energy and distributed energy resources;
- promote energy storage and electrification technologies necessary to decarbonize the environment and economy;
- prepare for future climate-driven impacts on the transmission and distribution systems;

- accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and
- minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the Commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter 21N

The Company's Plan meets the objectives of the legislation and is in line with the Commonwealth's pathway to a clean energy future.

The Company is proposing additional funding above its base funding for reliability and resiliency to support targeted undergrounding or targeted spacer cable in areas where vegetation management activities may not be allowed. SCADA Automation projects increase the monitoring and control of the system further out on the distribution system and allow for automated switching and restoration during outage events. The Company's ADMS and DERMS proposal will enable the Company to operate the system in a safe and reliable manner and optimize system demand and generation resources.

The Company's system forecast and demand assessment allows for the interconnection of 254 MW of solar, approximately 21,000 heat pumps and over 50,000 vehicles by 2050. The investments proposed in this Plan and future plans will serve as the foundation to serve all of these different load and resources. The Company has reviewed the forecast of DER interconnections and believes that the hosting capacity of the substation transformers and sub-transmission system will be sufficient if the upgrades identified in Section 6 are completed.

Unitil, through its EE and DERMs programs, is promoting and enabling energy storage and electrification technologies. The Company is also proposing studies and a compensation fund to enable DERs as grid services in coordination with the other EDCs, as well as proposing tools and software in preparation for the final FERC 2222 Oder that allows the aggregation of DERs.

In Section 10 the Company describes its approach to assessing the impact of climate change on our system. The next step for the Company is to develop alternatives to mitigate these risks.

This entire Plan is developed with affordability in mind. The Company's VVO program, when implemented, is designed to reduce customer loads by 2% without the customer taking any action. The financial savings flow directly to the customer. The reliability and resiliency programs will reduce the impact and costs of outages on our customers. Our EE programs provide incentives to promote electrification and efficiency measures

The table below summarizes the benefits associated with each investment project.

Project	Benefits
Enable DERs as Grid Services	• Compensation fund and mechanism to promote DERs as grid services • Connect up to 10 DERs greater than 500kW • 5MW to 10MW demand reduction across the system • Assuming five, 4-hour events, savings of 100 MW-Hr to 500 MW-Hr of energy savings. • Benefits EJC and non-EJC communities
ADMS / DERMS	• Foundational investment • Platform for SCADA, OMS, VVO and DERMS • Real time system monitoring and control • Functionalities: real-time load flow and circuit analysis, demand response, outage restoration, direct load control and network configuration. • Reduce outages by 10 minutes resulting in 360,000 customer minutes of savings and approximately $200,000 in annual customer savings • Integration of DERs • Benefits EJC and non-EJC communities
VVO	• Estimated 2% reduction in energy and demand • Approximately 2.5MVA in annual Peak Demand Reduction by 2029 • Approximately 7,700,000 kWh in annual energy reduction by 2029 • Approximately $3.2 million in annual bill savings by 2029 • Benefits accrue directly to customers without any customer interaction • Benefits EJC and non-EJC communities
SCADA Automation	• Foundational investment • Supports VVO implementation • Reliability savings - Based upon an example outage effecting 1,500 customers, this would translate to a savings between 15,000 customer minutes per outage

	• Real time telemetry • Historical interval data • Remote monitoring and control of field equipment • Benefits EJC and non-EJC communities
FERC 2222 Implementation	• Supports the ability for aggregated DERs to enter into the wholesale market • Reduce capacity constraints • Integrate an increased amount of renewable energy resources • Reduce GHG emissions • Support State energy policy • Defer distribution investment • Enable customers to take control of their energy future • Benefits EJC and non-EJC communities
Lunenburg Substation	• Alleviates loading constraints on Lunenburg Substation transformer and associated equipment • Increases load and DER hosting capacity by more than 15MW • Improved reliability of Lunenburg area by splitting 30W30 into two circuits • Location does not negatively impact and EJ community
New South Lunenburg Substation	• Alleviates loading constraints on 08 and 09 Lines and Flagg Pond Substation • Increases load and DER hosting capacity by more than 30MW • Improved reliability of system by implementing a second system supply in the area • Location does not negatively impact and EJ community
EV Charging and Make Ready	• Implemented TOU rates to further promote EV adoptions • Incentivize residential customers to adopt EVs, additional incentives for low and moderate income customers • Additional 5 Level 2 and 1 DCFC charger • Locations of charger can benefit EJ communities • 1,150 vehicles by 2029 and 2,291 vehicles by 2034

Targeted Reliability and Resiliency	• Targeted deployment of undergrounding and spacer cable in areas where traditional trimming is not allowed.
	• Typical savings estimates:
	    ○ 100% savings in CMI when select undergounding is used.
	    ○ 50% savings in CMI for outages caused by animals

	80% savings in CMI for outages caused by fallen tree limbs 50% savings in CMI for outages caused by fallen tree trunks 80% savings in CMI for outages caused by tree growth into the line 50% savings in CMI for outages caused by uprooted trees 80% savings in CMI for outages caused by vines • Reduced storm restoration costs related to less damage and fewer outside crews needed.
Energy Efficiency, Demand Response, and Heat Electrification	• Approximately 1.4 MW in demand response reduction • Approximately 1,242 metric tons of 2030 Avoided CO2e. • Over $23 million in total benefits • Contribute to the deferral of capital investments in some cases • Benefits EJC and non-EJC communities

Table 38 – Customer Benefits and Business Case for Proposed Investments

7.2 INVESTMENT SUMMARY 10-YEAR CHART

The spending shown below considers existing capital spending programs (base budget), pre-authorized programs (i.e. EE, grid modernization and electric vehicles), and newly proposed spending (i.e. capacity, extended grid modernization, reliability and resiliency and customer facing programs) for a 10-year period form 2025-2034.

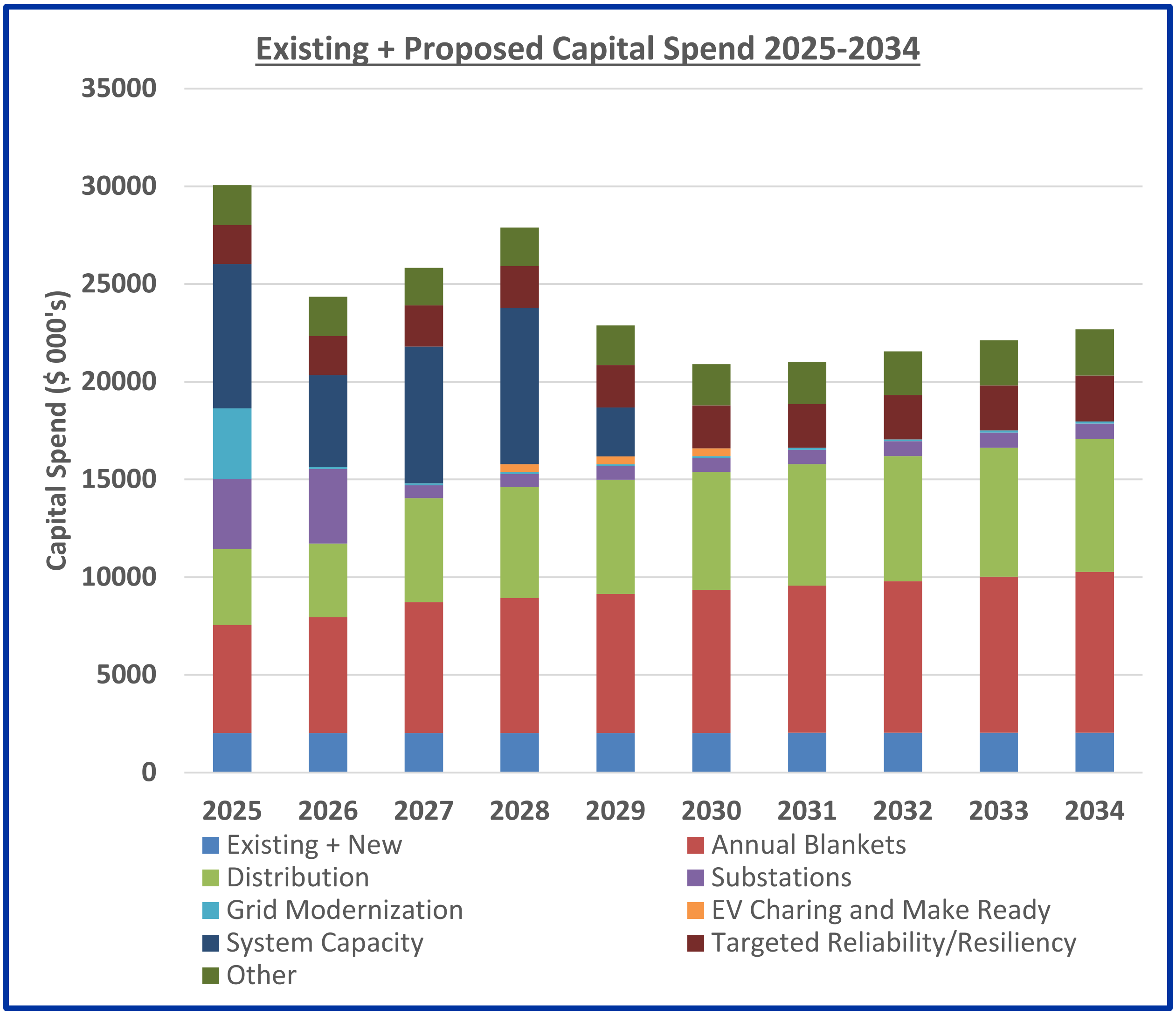

Figure 17 – 2025-2034 Capital Spending

7.3 EXECUTION RISKS – SITING, PERMITTING, SUPPLY CHAIN AND WORKFORCE CHALLENGES

The Company has taken a measured approach to this Plan. As a small utility, Unitil must focus on the needs of its customers. This plan consists of projects that are generally within the control of the Company from a design and construction standpoint. With that said, there are potential challenges to each of the projects proposed as part of this plan.

- Siting – Siting new electric infrastructure can be a challenging endeavor. The siting process takes time and patience. Siting electric infrastructure begins with identifying a constraint and study area. A transparent stakeholder engagement process which encourages feedback is critical to the success of the siting process. Identifying the possible range of solutions allows the stakeholders to understand the challenges and limitations of each solution. A detailed selection process that provides stakeholders with the opportunity to provide feedback will provide the greatest success for siting.

- Permitting – Permitting electric infrastructure may be one of the most challenging steps to completing a project, and can sometimes take just as long as siting. The larger the project, the more people it may impact and the more challenging it is to obtain permits. Each permit has its own process and its own group of stakeholders. Any single permit can hold up a project from construction within the timeframe when it is needed. Some projects can require over a dozen permits depending on where the project is located and how many cities or towns the project impacts. Local, State and Federal permitting boards are stakeholders and should be included early in the process. A transparent stakeholder engagement process which encourages feedback is critical to the success of the permitting process.

- Supply Chain – Supply chain issues continue to challenge project in-service dates. Transformers, voltage regulators and meters continue to experience delivery times of 18-24 months. Smart devices used to make the grid more intelligent are experiencing challenges due to the lead-time of the computer chips needed to operate. Vendor relationships are critical to the success in receiving equipment within a reasonable timeframe. Project in-service dates must be set at a reasonable timeframe to order and receive materials.

- Workforce – A diverse set of skills are required to complete a project. Technical staff is required to design and specify the equipment; purchasing agents are needed to complete the competitive bidding process for equipment and contract services; stockroom staff are required for purchasing and receiving goods and materials; construction supervisors are required to supervise the field staff; various different skillsets are required for construction; accounting and finance staff is required to account for the project; and so on. The future grid will need three times the capacity of the existing system. Increasing the size of the workforce is critical to the decarbonization goals of the Commonwealth. Workforce is discussed more in Section 12.

8 2035 - 2050 POLICY DRIVERS: ELECTRIC DEMAND ASSESSMENT

The Commonwealth has described many different approaches to achieving the 2050 goals for decarbonization. The Commonwealth Clean Energy and Climate Plan for 2050 targets a reduction in gross GHG emissions to at least 85% below the 1990 baseline level in 2050.[27] To reach this target, the Commonwealth has set sector-specific emissions sublimits.

The analysis informing the 2050 Roadmap Study highlights that electrification and the "All Options" pathway meet the 2050 emission reduction targets with the least cost while achieving deep decarbonization.[28] The Company's demand assessment forecast has been compared against the "All Options" pathway to ensure the Company's Plan will contribute to the overall Commonwealth goal. To accomplish this, the Company scaled the Commonwealth's goals and compared the scaled benchmark to the demand assessment. The assumptions in the Company's demand assessment matched very closely for electric vehicles, residential heat pumps, solar and energy storage. The Company's reviewed its demand assessment to ensure it is in line with the assumptions in the Commonwealth Energy Climate Plan for 2050[29]. The table below shows the comparison between the Commonwealth assumptions and the assumptions in the Company's demand assessment.

[27] Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050 Page 18.
[28] Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050 Page 20
[29] The Commonwealth Clean Energy and Climate Plan for 2050 assumes that 87% of the "small" (G41, G42, G43 and G51) commercial/industrial and 52% of the "large" (G52, G53 and Newark Special Contract) commercial/industrial gas load is electrified by 2050

Sector	Description	State Benchmark	Units	Scaled Benchmark	Units	Company Forecast	Units
Transportation Sector (Note 2)							
	Light-Duty EV	5,000,000		46,976	vehicles	52,841	vehicles
	Medium/Heavy Duty EV	353,000		3,316	vehicles		
Building Sector (Note 2)							
	Residential air source heat pumps	2,000,000		18,790	heat pumps	21,201	heat pumps
	Residential Ground source heat pumps	195,000		1,832	heat pumps		
	Residential EE Retrofits	1,300,000		12,214	homes	0	
	Commercial air source heat pumps	1,500,000,000		14,092,698	sq. ft.	Note 3	
	Commercial ground source heat pumps	140,000,000		1,315,319	sq. ft.	Note 3	
Power Sector (Note 2)							
	Offshore Wind	23.0	GW	216	MW		
	Onshore Wind	1.0	GW	9	MW		
	Solar	27.0	GW	254	MW	254	MW
	Storage	5.8	GW	54	MW	60	MW
Note 1	Massachusetts Census Data 2020						
	https://malegislature.gov/Redistricting/MassachusettsCensusData/CityTown						
Note 2	2050 Clean Energy and Climate Plan, Table 3-3						
	https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download						
Note 3	Company forecasts are based on peak gas usage of gas C&I customers						

Table 39 - Demand Assessment Assumption Comparison[30]

2035 to 2050 Peak Load Forecasts

Hourly interval load forecasts for both the winter and summer season for each of the years from 2035 to 2050 where developed by combining the hourly interval base, DER, ESS, EV and electrification forecasts above and incorporating VVO load reduction. The overall system peak load forecasts is the peak hourly load (winter or summer) of each year. The Company's 2035 to 2050 system peak load forecasts are included below.

[30] Due to the Company's overall size, the probability for large scale wind (either on-shore or off-shore) to have an impact on the electric system is very low, as wind is more of a supply consideration for the Company. The Company has not included wind in its demand assessment.

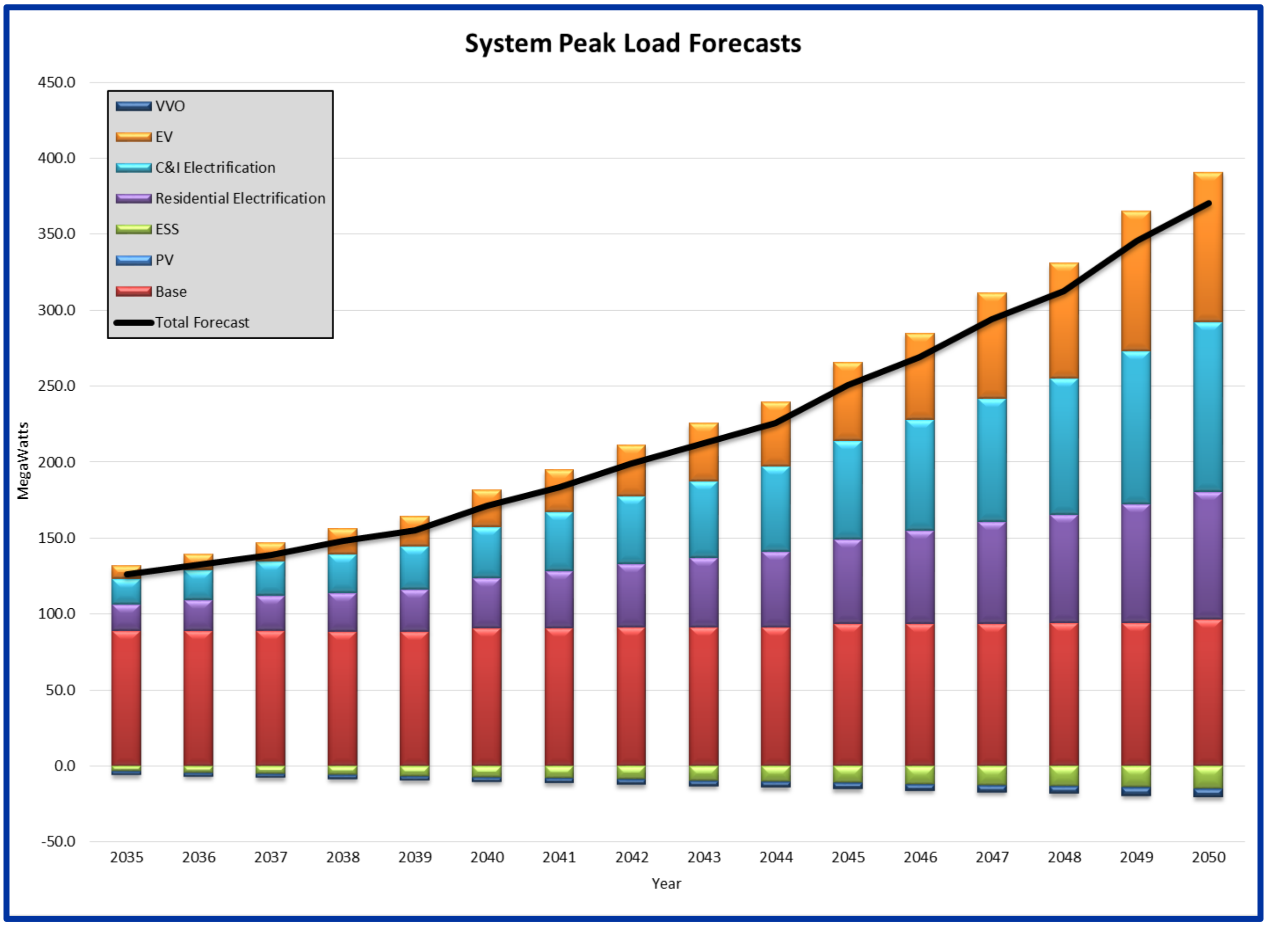

Figure 18 – Ten Year System Peak Load Forecast

	Total Peak Forecast (MW)	Contribution to Total (MW)							Season ESS	Hour
		Base	PV	ESS	Residential Electrification	C&I Electrification	Base	PV		
2035	128.4	89.0	0.0	-3.8	17.6	16.8	8.4	-2.3	Winter	7PM
2036	135.7	89.1	0.0	-4.5	20.4	19.6	10.5	-2.4	Winter	7PM
2037	142.4	89.3	0.0	-5.3	22.9	22.4	12.2	-2.5	Winter	7PM
2038	151.6	88.6	0.0	-6.0	25.5	25.3	17.2	-2.6	Winter	7PM
2039	158.9	88.7	0.0	-6.8	27.9	28.1	19.7	-2.7	Winter	7PM
2040	175.9	91.0	0.0	-7.5	32.7	33.7	24.2	-2.9	Winter	7PM
2041	189.1	91.1	0.0	-8.3	37.2	39.3	27.5	-3.1	Winter	7PM
2042	205.2	91.2	0.0	-9.0	41.7	44.9	33.7	-3.3	Winter	7PM
2043	218.9	91.3	0.0	-9.8	45.8	50.5	37.9	-3.5	Winter	7PM
2044	232.8	91.4	0.0	-10.5	50.0	56.1	42.1	-3.7	Winter	7PM
2045	258.4	93.7	0.0	-11.3	55.8	64.5	51.6	-4.0	Winter	7PM
2046	277.8	93.8	0.0	-12.0	61.6	73.0	56.8	-4.3	Winter	7PM
2047	303.9	94.0	0.0	-12.8	66.8	81.4	69.4	-4.6	Winter	7PM
2048	322.9	94.1	0.0	-13.5	71.6	89.8	75.4	-4.9	Winter	7PM
2049	357.1	94.2	0.0	-14.3	78.1	101.0	92.1	-5.4	Winter	7PM
2050	382.5	96.5	0.0	-15.0	83.8	112.2	98.5	-5.7	Winter	7PM

Table 40 – Ten Year System Peak Load Forecast

Net Powerflow

Net Powerflow forecasts are included in the table below. These were developed in a similar fashion to the 2025 to 2034 net powerflow forecasts.

Year	Net Powerflow (MW)
2035	-19
2036	-24
2037	-28
2038	-33
2039	-37
2040	-43
2041	-49
2042	-54
2043	-59
2044	-63
2045	-68
2046	-74
2047	-81
2048	-86
2049	-92
2050	-99

Table 41 – Ten Year Net Powerflow Forecast

There is a great deal of uncertainty when attempting forecasting loads to 2050. Changes in technology, cost of technology can change drastically. Incentives and subsidies can have an effect of accelerating or slowing adoption rates. Technological advancement is a large unknown in this analysis. The Company expects this forecast will change over time and will continue to identifies ways to increase the accuracy of the forecast.

8.1 REVIEW OF ASSUMPTIONS AND COMPARISONS ACROSS EDCS

The EDCs together have reviewed and compared overarching assumptions specific to future electric demand assessments across the Commonwealth. The overall strategies employed by each individual EDC share many similarities, in particular applying and assessing the impact of state level electrification and clean energy scenarios for the buildings, transportation, and energy sectors. The EDCs adopt a scenario-based load assessment methodology and develop DER scenarios from the different decarbonization scenarios or 'pathways' outlined in the Massachusetts 2050 Decarbonization Roadmap (the 2050 Roadmap) and the Massachusetts Clean Energy and Climate Plan ("CECP") for 2025 and 2030 .

For the heating electrification sector, Unitil's building electrification forecasts are based on the number of residential customers served and average home size and an assumed btu/sq.ft. for heating and air conditioning as well as demand assumptions for residential gas customers that could convert gas appliances (range and dryer) to electric. Commercial/Industrial electrification forecasts are based existing gas usage. Eversource looks at scenarios from an independent study of the 2050 Roadmap that was conducted as part of the DPU MA 20-80 Docket , named the "Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals" report (or "Future of Gas" report). The study generated electrification projections for the 'All Options' pathway (known as 'High Electrification' in the DPU study) and other scenarios with updated assumptions specific to building transformations. Eversource is focusing its efforts for electric demand assessments on four scenarios: High electrification ('All options'), Hybrid Heating, Targeted Electrification, and Networked Geothermal. National Grid looks at the Phased scenario, the Full Electrification scenario, and the Hybrid scenario outlined in CECP.

For the energy efficiency outlook, the EDCs assume that energy efficiency offerings continue in line with historic trends. For Demand Response, National Grid assumes company programs continue. Eversource and Unitil currently do not consider demand response applications (see Section 8.2.4).

For the transportation electrification sector, Unitil compared the details of its demand assessment (including quantity of EVs) to the "All Options" pathway to ensure the demand assessment was in line with the decarbonization goals of the Commonwealth. Eversource looks at the same independent study as discussed in the above heating electrification sector. Transportation sector electrification is consistent across the multiple scenarios in the study and is based on the high electrification scenario/assumption. National Grid evaluates the load impacts of scenarios from adopting the California Advanced Clean Car (ACC II) Rule and Advanced Clean Truck Rule. Both rules have been adopted by the State of Massachusetts and yield scenarios that align with the State's decarbonization pathway.

For DG, the EDCs assess the "All-Options" scenario outlined in the 2050 Roadmap. This scenario is described as one that "selects the most economic resources to meet emissions limits using baseline cost assumptions." It provides an outlook on connected solar capacity, including both rooftop and ground-mounted, through year 2050. Unitil and National Grid assumes energy storage aligns with the 'All Options' pathway outlined in the 2050 Roadmap. The Company extended its Base Peak Load Forecasts from 2035 to 2050 utilizing the average annual growth rate of 0.14% from 2024 to 2033. Additionally, the Company incorporated a step adjustment every five years (2035, 2040, 2045 and 2050) to account for forecasted large customer additions.

The step adjustment was assumed to be 3% of the average forecasts load from 2024 to 2033. Eversource is actively researching the penetration and viability of long-term energy storage solutions in its territory.

8.2 BUILDINGS: ELECTRIFICATION AND ENERGY EFFICIENCY ASSUMPTIONS AND FORECASTS

Building electrification will have the largest effect on electric peak load conditions of any other electrification technology. The energy needed to heat a given area is much greater than cooling the same area. When cooling an area, the temperature may need to be decreased by 10 degrees to make the area comfortable. However, in heating applications, temperature may need to be increased by 18 to 68 degrees[31] compared to the outdoor temperature to make the area comfortable.[32] Also in heating applications, the temperature drops much faster (depending on the efficiency of the building envelope) resulting in the heating system running more frequently to maintain temperature. In addition, as the ambient temperature decreases, the overall efficiency of the heat pump will have a tendency to decrease, resulting in increased electric loads to heat the same area.

Electrification of heating loads will have the effect of transitioning the system peaks from the summer (due to cooling loads) to the winter (due to electrified heating loads). In addition, those peaks are likely to occur in the morning hours when customers wake up and business open for the day. Cooling peak loads have typically overlapped with solar production during the middle of the day. However, heating peak loads will happen early enough in the morning that the contribution from solar production on the system will be minimal.

The forecasting of 2035 to 2050 electrification load was done similarly to how electrification was forecasted for 2025 to 2034 with lower coincident factors and 5 percent[33] adoption rates (percentage of total forecasted load incorporated per year).

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[31] 18 degrees assumes an outdoor air temperature of 50 degrees and an internal setpoint of 68 degrees and 68 degrees refers to an outdoor temperature of 0 degrees with an internal setpoint of 68 degrees.
[32] MA 105 MCR 410.180 requires temperatures of at least 64 degrees Fahrenheit at night and 68 degrees Fahrenheit during the day from September 15 to May 31.
[33] 5 percent per year adoption rates were used to be in line with the Commonwealth Clean Energy Climate Plan for 2050.

8.2.1 Technology assumptions

The Company focuses this analysis on residential electrification (heating and appliances) and commercial electrification (electrification of gas loads).

Residential Electrification:

The Company considers two types of residential electrification in its load projections, appliance load and heating/air conditioning load. In order to develop load forecasts for each of these load types the Company made the following assumptions.

- An average square footage of a residential dwelling in the service territory of 1,500 square feet.
- Heating/AC Sizing[34]
  - 20 btu/sq. ft. for air conditioning
  - 50 btu/ sq. ft. for heating
- Heating/AC Heat Pump SEER of 18[35] (13.68 btu/W)
- Current customer AC usage
  - 30% with central AC
  - 40% with window AC
  - 30% with no AC
- All natural gas customers have gas heat, ranges and dryers.
- Typical Electric Dryer Peak Load of 5kW[36]
- Typical Electric Range Peak Load of 6kW[37]

[34] Based upon International Energy Conservation Climate Zone Map
[35] Based upon manufacturer data for an "average" efficiency unit
[36] Based upon typical nameplate data and National Electric Code loads.
[37] Based upon typical nameplate data and National Electric Code loads.

Hour of Day	Appliance	Heat/AC	Hour of Day	Appliance	Heat/AC
0:00	5%	50%	12:00	25%	65%
1:00	5%	50%	13:00	25%	65%
2:00	5%	50%	14:00	10%	80%
3:00	5%	50%	15:00	10%	80%
4:00	5%	50%	16:00	25%	80%
5:00	10%	65%	17:00	25%	80%
6:00	15%	65%	18:00	25%	80%
7:00	25%	80%	19:00	25%	80%
8:00	25%	80%	20:00	10%	80%
9:00	10%	65%	21:00	10%	80%
10:00	10%	65%	22:00	10%	65%
11:00	10%	65%	23:00	5%	50%

Table 42 – Hourly Electrification Utilization

The assumptions above along with coincident assumptions, which decrease over time based on the amount of electrification were used to develop hourly residential electrification peak day forecasts. The hourly residential electrification forecasts are then added to the hourly base seasonal peak load forecasts.

Commercial/Industrial Electrification:

The Company utilized peak gas loads for all commercial/industrial gas customers as the basis for is commercial/industrial electrification load forecasts along with typical hourly electric profiles for the same customer types and the following assumptions to hourly commercial/industrial electrification load forecasts. These forecasts were then added to the hourly base seasonal peak load forecasts.

- Estimates Peak Hour Gas Usage[38]
    - "Small" Commercial/Industrial – 437 DTH
    - "Large" Commercial/Industrial – 61 DTH
- 293 kW/DTH
- % of Customers to Electrify[39]
    - "Small" Commercial/Industrial – 87%
    - "Large" Commercial/Industrial – 52%

8.2.2 Adoption propensity assumptions

The Company has taken the following approach to adoption:

- Adoption (% of Total Forecasted Load Incorporated per Year)
    - 2025-2029 – 1%
    - 2030-2034 – 2%
- 80% of all residential customers will convert to electric heat by 2050[40]

8.2.3 Building code assumptions

This assessment does not consider changes in the building codes. Changes to building codes will have the greatest impact on space heating with heat pumps. As the overall building envelope improves, smaller heat pumps can be used thus reducing the overall demand.

8.2.4 Demand response scenarios – impacts on heating demand

The Company's load forecast did not assume demand response as the penetration of heat pumps is low. In addition, customer behaviors on the coldest days of the year may limit participation in the demand response program or the results of the program could be skewed by pre- or post-heating thus creating an inadvertent peak condition. The Company will continue to evaluate demand response programs for heating and how those programs could be modeled in the forecast.

[38] Based upon "average" Unitil customer

[39] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

[40] Based upon Commonwealth Clean Energy and Climate Plan for 2050, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

8.3 TRANSPORT: ELECTRIC VEHICLE ASSUMPTIONS AND FORECASTS

Under the "All Options" pathway, electric vehicle charging will have a large contribution to the electric loads. Electric vehicle charging can be highly variable based upon location, time of day and amount of load. Electric vehicles can charge at any point during the day which may create challenges as well as opportunities for the electric system depending upon where and when the charging occurs. Transitioning to a high penetration of electric vehicles means EV owners have the ability to charge where they need to: work, home, stores, etc.

Electric vehicle charging in the evening, at the time of system peak loads, can create challenges and increase system peaks. Vehicle charging during the day can help to offset some of the solar generation during the shoulder months of the year when solar generation exceeds the system loads. Electric vehicle charging overnight can benefit the system by shifting charging away from the peak load hours. As the shift in system peak loads transition to winter peak system loads, the probability of a high amount of electric vehicle charging to occur early in the morning is unlikely.

As is the case with electrification forecasts, the Company used the same methodology for forecasting EV charger load for 2035 to 2050 as it did for years 2025-2034. The only change made was to assume the Company's "High Rate" or 100% of the ISO-NE EV Adoption Forecasts from 2036 to 2050.

8.3.1 Technology assumptions

The Company's EV load forecasts consider the following types of EV charging:

- Level 1 Charging – Utilizes a standard 110V wall to charge an EV in about half a day. Generally speaking, charging an EV at home adds about 3,000 kWh to annual consumption or 275 kWh per month. You'll see an increase in your monthly electricity bill that is offset by fewer trips to the gas station. The demand assumption for a Level 1 charger is 1.7kW.
- Level 2 Charging - Level 2 charging options require professional installation of a 240V outlet (similar to a clothes dryer) that enables a faster vehicle charge. Coupled with a smart EV charger that shares a data connection with the EV and the charging operator, it's an intelligent system that provides real-time information. The demand assumption for a Level 2 charger is 9.6kW.
- Direct Current Fact Charging (DCFC) - DCFC (previously referred to as Level 3 Charging), can recharge a vehicle in as little as 30 minutes, depending on the model. This

commercial-level charging option is largely being explored by state/government entities along interstate highways and still faces some major challenges for large-scale implementation, including cost, compatibility and specialized infrastructure needs. The demand assumption for a Level 1 charger is 600kW.

The forecast also assumes that every EV owner will have some form of home EV Charging. 33% of EV owners will use Level 1 chargers and 67% will have Level 2 charging at home.

8.3.2 Adoption propensity assumptions

The Company also separately forecasts ten EV charging load forecasts that get incorporated into the base system load forecasts. The ISO-NE EV Adoption Forecasts by state were used as the basis for the Company's EV load projections. These ISO-NE forecasts along with ISO-NE EV stock (registered) by state data was used to project the number of EVs on the road and ultimately the number of EV chargers within Unitil's service territories.

ISO-NE information on the number of EVs currently registered in Massachusetts was used to estimate the current number of EVs in the service territory. Once the number of EVs was determined, the ISO-NE EV Adoption Forecasts were used to project the number of EVs. Two forecasts for each territory were created:

- High Rate – utilizes 100% of the ISO-NE EV Adoption Forecasts
- Baseline Rate – utilizes 67% of the ISO-NE EV Adoption Forecasts

Utilizing the assumptions in the section below, the estimated number of home level 1 and level 2 chargers in the service territory was calculated. EEI projections for the percentages of the total number of each type of level 2 charger allowed for the calculation of the estimated number of level 2 public and work place chargers.

Utilization percentages (percentage of total of each type of units charging) for each hour of the day for home, public (including DC fast chargers) and workplace chargers and the assumed demand for each type of charger was then used to calculate the forecasted load due to EV charging for each hour of the day.

8.3.3 Mileage, and time of day assumptions

The Company uses the following time of day and location of charging assumptions in its forecast.

Hour of Day	Home	Public	Workplace	Hour of Day	Home	Public	Workplace
0:00	75%	25%	5%	12:00	15%	75%	60%
1:00	75%	25%	5%	13:00	15%	60%	60%
2:00	75%	25%	5%	14:00	15%	60%	60%
3:00	75%	25%	5%	15:00	25%	50%	60%
4:00	75%	25%	5%	16:00	30%	40%	50%
5:00	60%	25%	5%	17:00	40%	40%	40%
6:00	50%	35%	5%	18:00	50%	30%	15%
7:00	50%	35%	10%	19:00	60%	30%	10%
8:00	40%	50%	15%	20:00	60%	30%	5%
9:00	30%	60%	60%	21:00	60%	30%	5%
10:00	15%	75%	60%	22:00	75%	30%	5%
11:00	15%	75%	60%	23:00	75%	25%	5%

Table 43 – Hourly EV Utilization

8.3.4 Managed charging scenarios – Impacts on EV demand

At the present time, the Company does not have an EV managed charging program. Therefore, the load forecast did not assume managed charging. However, managed charging programs may be a necessity to control peak loading and system investment required for transportation electrification. The Company looks forward to working with the Department and stakeholders in the near future on a state-wide approach to EV managed charging.

8.4 DER: PV/ESS – STATE INCENTIVE DRIVEN ASSUMPTIONS AND FORECASTS

The 2050 Clean Energy and Climate Plan identifies that distributed solar and energy storage are critical to achieving the Commonwealth's decarbonization goals. The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the future grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs.

The Company continues to experience a high penetration rate of DERs with the total capacity of generation accounting for over 70% of the peak load, and totals over 300% of the minimum daytime load. The diversity and penetration of DER installations can have the impact of deferring investments in system capacity. The Company's approach to forecasting and planning its electric system assumes an increased interest in interconnections.

Hosting capacity analysis identifies portions of the system where DERs can be installed without the need for costly system improvements. The Company has an interactive mapping system designed for customers and developers to see if their potential project is located in an area where system improvements are likely to be needed or if their project can generally proceed without the need for a costly improvement. This empowers customers to make decisions on their investment in technology. The Company's goal is to continue to identify ways to increase the hosting capacity of the system.

Locational value analysis identifies the value that a DER would have to different parts of the system. Locational value analysis is a measure of how much traditional system investment in capacity can be deferred through the installation of a DER. Reliability, capacity and availability are important factors to consider in locational value analysis.

8.4.1 Technology assumptions

The Company categorizes DER facilities into the following:

- Utility Scale DER Facility - Any DER facility with a nameplate capacity of 1,000kW or more
- Large DER Facility - Any DER facility with a nameplate capacity less than 1,000kW and up to and including 500kW
- Medium DER Facility - Any DER facility with a nameplate capacity less than 500kW and greater than 60kW
- Small DER Facility - Any DER facility with a nameplate capacity of 60kW or less

The DER/PV forecasts for 2035 to 2050 utilize the same methodology as the forecasts for 2025 to 2034. However, starting in 2035 the Company assumed the addition of one additional "large" DER/PV facility per year through 2050.

8.4.2 Adoption propensity assumptions

The process for creating DER Forecasts requires the development of ten year DER Projections for the installations of small and medium DER facilities. These DER Projections are then added to all sizes of DER facilities that are installed or approved for installation at the time the DER Forecast is developed for each distribution circuit, distribution substation transformer and the overall system. The overall system DER Forecasts also include the projected penetration of large DER facilities.

Due to the limited number and uncertainty of location of Large DER Facilities, these are not included in the circuit and substation transformer DER Projections. Similarly, Utility Scale DER Facilities are not included in circuit, substation transformer, nor system DER Forecasts. Instead these facilities will be treated similarly to how new large customer load additions are incorporated into distribution load projections in that they will be added to the DER Forecasts as actual customer applications are received per the project schedule and engineering judgement.

Distribution circuit DER Forecasts are developed using two similar methods and taking the higher result of the two methods as the ultimate DER Forecasts for each circuit.

- <u>Method 1</u> – Forecast Based on Nominal DER Capacity:

  Method 1 utilizes the nominal capacity of small and medium DER facilities installed on the circuit and "normalizes" this to the three-year historical circuit peak load. A five-year and three-year historical slope is calculated based on the five-year normalized DER capacity growth on the circuit. This is done for all distribution circuits on each of Unitil's distribution operating systems.

  Based on the calculated slopes engineering judgement is used to create four growth rate ranges for each distribution operating company.
    - N – slope of zero
    - L – flat slope
    - M – moderate slope
    - A – aggressive slope

  Each circuit is assigned a historical growth rate. Based on the historical growth rates future growth rates are calculated for each of the rate types. The future rate for each type is the maximum of the three-year average and five-year average of each historical rate of that rate type.

After reviewing the assigned historical rate type for both the three-year and five-year slopes engineering judgement is used to assign the desired future growth rate (slope) to each circuit. This slope is then used to calculate the small and medium DER Projections that is added to the total amount of DER installed and approved for installation on each circuit to get the method 1 DER Forecasts.

- <u>Method 2</u> – Forecasts Based on Number of DER Facilities Installed:

  Method 2 is very much the same as method 1 with one exception. Method 2 utilizes the number of small and medium DER facilities on each circuit and "normalizes" this to the average number of customers supplied by each circuit. The same process described in method 1 is then used to project the number of small and medium units that will be installed on the circuit. The projected number of units is then multiplied by the five-year average size of small and medium units to determine the DER Projections of small and medium DER facilities for each circuit. This is added to the total amount of DER installed and approved for installation on each circuit to get the final method 2 DER Forecasts.

8.4.3 Time of day assumptions

The propensity of the DER connected (and forecast to connect) to the system is solar. Load curves from existing solar facilities are used to approximate the load curves of the new solar connections. The Company uses these load curves to estimate how the DERs will impact the overall system load curve under peak load and light load conditions.

8.5 GRID MODERNIZATION: VVO AND FORECASTS

The Company considers grid modernization and the performance of VVO critical to the future of the electric distribution system. The Company includes in its planning guidelines criteria for the continued evaluation and if needed recommended changes to its VVO program to ensure it continues to provide load reducing and DER operational benefits.

The Company included the same VVO load reduction assumptions in its 2035 to 2050 load forecasts as it did in its 2025 to 2034 forecasts.

8.6 OFFSHORE WIND FORECASTS (PROCUREMENT MANDATES, GIA STATUS, POIS)

The 2022 Climate Act codifies a goal of procuring 5,600 MW of offshore wind no later than June 30, 2027. The Act also allows the Commonwealth to coordinate offshore wind solicitations with other New England states and removes the price cap that previously guided project developers' bids in response to a state-issued solicitation. The Act further sets preferences for project proposals that make commitments to, among other things, developing equitable workforce opportunities and limiting negative environmental and socioeconomic impacts.

On August 23, 2023, DPU approved the state's fourth round of offshore wind solicitations intending to procure at least 400 MW and up to 3,600 MW of offshore wind.[41]

The Company's small footprint does not lend itself to the large-scale deployment of wind. Also, the Company has a limited amount of transmission infrastructure, so transmission level projects should not have a significant impact on the Company's system.

8.7 CURRENTLY PROJECTED CLEAN ENERGY RESOURCE MIX

The Company's demand assessment is forecast to design a system to accommodate the high penetration of electric vehicles for both individual as well as medium/heavy duty EVs, as well as residential and commercial electrification, onshore and offshore wind, solar and energy storage. The Company will continue to re-evaluate its forecasts to make further improvements as adoption rates change in the near and mid-term.

9 2035 - 2050 SOLUTION SET – BUILDING A DECARBONIZED FUTURE

The first ten years of electric sector modernization is rather clear and focuses on the capacity and resiliency of the electric system to meet the forecasted demands of electrification and DER integration as well to increase the resiliency of the electric system to withstand increasing major storm events caused by climate change. Beyond 2035, there are many different pathways that can be taken to support the State's decarbonization goals. Those pathways may need to consider: 1) the installation of behind the meter technology and incentives to empower users to

[41] D.P.U. 23-42, *Joint Petition of the Massachusetts Department of Energy Resources et al*, Order at 91 (August 23, 2023).

take control of their energy usage; 2) the continued improvement in building energy efficiency standards and heat pump efficiencies; 3) continued deployment of EV charging and incentive mechanisms to attract participation; 4) load management and incentive designs; and 5) battery storage charge management.

In addition to the advancement of behind the meter technologies and incentive programs past 2035, the electric system is still faced with the challenge of aging substation infrastructure. The replacement of this equipment provides the opportunity to continue to increase the overall load and DER hosting capacity of the system while addressing aging infrastructure. Non-wires alternatives will hopefully see improvements in reliability, capacity and availability to the point where they may become cost effective alternatives to traditional investment. Technologies to decarbonize the gas distribution system may continue to improve the cost, availability and safety of the alternatives. System optimization will continue with increased monitoring and control of the resources connected to the electric system. Incentive mechanisms will be in place to incentive customers to allow their equipment to be operated to the benefit of the system.

9.1 CLEAN ENERGY SOLUTIONS INCLUDING BEHIND THE METER INCENTIVE DESIGN SCENARIOS (IMPACT ON ELECTRIFICATION DEMAND)

Based upon the load forecast presented in this Plan, system loads are forecast to increase by 3 to 4 times between now and 2050. Some of the electrification can be offset with DERs, but the system must be designed to reliably serve the increase in demand. Innovative rate designs and pricing structures will be required to prevent an increase in load on the electric system due to pricing incentives.

9.1.1 Buildings: Winter demand response scenarios and associated preliminary incentive designs

Heat pumps will have the effect of lowering summer peak load, but will tend to increase winter peak loads. As demonstrated in the load forecast, the Company expects to transition from a summer peaking system to a winter peaking system by 2034. This transition in system peak is driven by the electrification of heating loads traditionally served by fossil fuels as well as electric vehicle charging.

The American Council for an Energy-Efficient Economy ("ACEEE"), a nonprofit research organization, completed a report[42] that found that for better-sealed homes, higher-performing heat pumps and grid interactive measures like water-heating systems that heat water at lower demand times could reduce the winter peak by up to 12%.

As the outside ambient temperature decreases, the coefficient of performance for the heat pump drops. In many cases, the BTU output of heat pumps can drop in half as the ambient outdoor temperature approaches 0 degrees Fahrenheit. The heat pump industry has worked to improve the coefficient of performance at lower temperatures. Continued improvements in energy efficiency programs specifically focused on the winterization of buildings may support electrification by allowing smaller heat pumps to be used. Continued improvements to building codes will also help support the use of smaller, more efficient heat pumps.

Innovative rate designs will be required to manage or mitigate loads during winter peak times. Those rate designs should incentivize customers to reduce loads (i.e. turning off the heat pump or increasing the setpoint) during certain periods of time. Another approach is for the Company to control an aggregated grouping of heat pumps and compensate customers for participating in the program.

9.1.2 Transport: Electric vehicle charging demand management scenarios and associated preliminary incentive designs (discussion of both $/kW incentives to attract participation and ongoing c/kWh incentives to subsidize O&M especially in targeted EJ communities)

The Company has approved residential electric vehicle TOU rates. These rates became effective April 1, 2023. Service under this schedule is specifically limited to residential customers who take service restricted to charging a battery electric vehicle or plug-in hybrid electric vehicle via a recharging outlet at the customer's premises. This schedule is not available to customers with a conventional charge sustaining (battery recharged solely from the vehicle's on-board generator) hybrid electric vehicle.

[42] https://www.aceee.org/research-report/u2101 - dated April 15, 2021

Energy supply is available on a time of use basis for the Company's Basic Service customers[43]. For the purpose of billing, "On-Peak" is defined to be between the hours of 3:00 P.M. and 8:00 P.M. (local time) for all non-holiday weekdays, Monday through Friday. "Mid-Peak" is defined to be between the hours of 6:00 A.M. to 3:00 P.M. daily Monday through Friday, except holidays. "Off-Peak" is defined to be between the hours of 8:00 P.M. to 6:00 A.M. daily Monday through Friday and all day on holidays and weekends.

The Company's EV TOU rate (EV-RES) took effect only recently, and customer adoption continues to evolve. At this point, the Company has not completed analysis on the optimal $/kW incentives to attract participation or the ongoing cents/kW incentives to subsidize O&M (especially in EJ communities). As participation continues to grow, the Company will continue to carefully evaluate the TOU model for this purpose. .

An unintended consequence of the current TOU design is that all vehicles could charge at an off-peak time (e.g., 8:00pm). Demand management[44] for EV charging may be required to "smooth out" the charging load associated with "off-peak" charging. Demand management for EVs will need to include not only penalties for charging at certain times, but incentives for discharging back to the grid at certain times.

On a small scale, this is already accomplished at a charging station. When a second car plugs into a charging station, the charger automatically adjusts the charging of the first vehicle so as not overload the charger. This concept may be used in the future as part of a DERMS or other control scheme that can use real time circuit loads to provide information to participating vehicle chargers and control loads on a circuit or substation scale.

9.1.3 Other load management response scenarios and associated preliminary incentive designs

Innovative rate design is driven by timely and accurate data. The Company's Advanced Metering Infrastructure, Meter Data Management system and Customer Information System provide the

[43] At this time, customers on competitive electric supply or in a municipal aggregation may only participate in time-varying distribution and transmission charges, as applicable.
[44] Demand management is the balancing of loads at any given time to keep overall loads below a certain capacity.

tools required to provide timely and accurate metering data for many different types of innovative rate designs and coupled with data sharing platforms, allow customers to make informed energy choices.

Innovative rates should be based on cost of service rate design principles to ensure economic efficiency and limit cost shifting. Critical Peak Pricing ("CPP") and demand reduction approaches are also worthy of consideration in addition to tariff-based TOU rates.

Marginal energy costs are typically driven by wholesale electric market (ISO-NE in this case) factors and may not fluctuate for different customer segments. A utility's distribution-related costs are fixed in nature and are incurred to meet customers' non-coincident peak demands and do not necessarily exhibit time-varying cost characteristics. In most cases, demand charges for C&I customers better reflect the manner in which a utility's costs are incurred to serve such larger customers. Incremental loads may require new transformers, service lines and meter upgrades. Instances may also exist where the addition of loads would require an upstream feeder and/or substation upgrade.

The Company believes the rate design options for any type of electric load should be designed to promote the efficient use of the utility's electric system resources and reduce costs for all utility customers. Rate options must provide proper price signals and influence customer behavior in a manner that creates beneficial outcomes for the customer (through lower rates and electric bills) and for the utility (through a reduction in system costs over time). To achieve these objectives, the design of the rate options should only reflect system costs that are time-varying in nature, and provide customers a cost-based price signal through the rate design. The time-varying costs should drive the desired shape of the utility's system load curve and not simply represent a preconceived outcome based on non-cost or qualitative presumptions.

At the same time, it is also necessary to understand and evaluate how customers are responding to the utility's TOU rate options in order to make periodic refinements to the TOU rate design and identify how the utility's load shape and resulting costs will likely change over time. For example, some customers may find certain TOU rate design options to possess overly long peak time periods, precluding those customers from responding to the TOU rate in a meaningful way. In addition, some jurisdictions have designed TOU rates to create a significant peak to off-peak rate differential to increase the likelihood of a positive customer response without recognizing that the underlying costs of the utility are not accurately reflected by the rate design. In that case, a rate benefit is afforded to customers who can change their electric usage patterns even though the utility does not experience a corresponding reduction in cost. This may be deemed desirable for non-cost causative objectives, such as supporting technology adoption, gaining an understanding of consumer behavior, and insights into grid operations and future investment requirements by the utility.

Innovative rate design considers the effect that technology adoption will have on the electric distribution system and subsequent system planning and investment. Technology adoption rates should be forecast over the coming years and integrate these loads into planning studies and load forecasts. Possible changes to engineering and construction standards may be warranted to ensure reliability, safety, and appropriate equipment sizing.

The design of electric services may need to change as well, such as shorter distances and increased conductor size to address voltage drop concerns. Ongoing capital budgeting may need to accommodate early replacement of current infrastructure that is undersized and unable to accommodate new customer loads. Additionally, the installation of interval metering should be considered for increasingly dynamic loads and generation that have the potential to export energy onto the distribution system and necessitate more granular planning analyses.

Innovative rate design may also include make-ready programs, charging incentives, and behind the meter partnerships with third parties. Data sharing between the utility, customers and third parties can also be a solution to overcoming barriers to customer adoption. The Company continues to work on data sharing tools and standards (e.g., Green Button). Home energy management systems have become widely available, with lower costs over time. Data sharing standards and platforms should be considered that benefit the customer, the utility, society at large, and third-party vendors.

9.1.4 Battery storage charge management and associated preliminary incentive designs

As stated above, demand management for battery charging may be required to "smooth out" the charging load associated with "off-peak" charging. Demand management for batteries will need to include not only penalties for charging at certain times, but incentives for discharging back to the grid at certain times. As the costs of FTM and BTM batteries continue to decrease the adoption will increase. Batteries offer a reliable resource the electric system can depend upon if they can be controlled in a way to ensure they are available when called upon.

9.2 AGGREGATE SUBSTATION NEEDS –JAKE

The Company evaluated the adequacy of major electric system components at the load levels included in Section 8 above. This review assumed the proposed projects in section 6.4 are complete. The following table summarizes the system deficiencies identified through this process. The table is sorted by year. The system constraint is listed in the year when it first violates planning criteria.

Year	System Constraint	Circumstances
2035	Rindge Road – 13.8kV Regulators – Loaded Above Normal Rating	Basecase – Reverse Powerflow
2036	Townsend S/S – 15T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
	Sawyer Passway S/S – Circuit 22W1 Mainline Conductor – Loaded Above Normal	Basecase
2037	Flagg Pond S/S – 4T1, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T2
	Flagg Pond S/S – 4T2, 115kV-69kV, 100MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Flagg Pond 4T1
	Princeton Road S/S – 50T3, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	Basecase
2038	Pleasant Street S/S – 39T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase – Reverse Powerflow
2040	01 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 02 Line from Flagg Pond S/S to Summer Street S/S
	02 Line – Flagg Pond S/S to Summer Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 01 Line from Flagg Pond S/S to Summer Street S/S
	Summer Street S/S – 40T1, 69kV-13.8kV, 35MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of 06 Line from Summer Street S/S to Sawyer Passway S/S
2041	West Townsend S/S – 15T1, 69kV-13.8kV, 10.5MVA Transformer – Loaded Above Normal Rating	Basecase
2042	Canton Street S/S – 11T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase
2043	08 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Pleasant Street S/S to Lunenburg S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Princeton Road S/S – 50T2, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Princeton Road 50T3
2044	Summer Street S/S – Circuit 40W40 Mainline Conductor – Loaded Above Normal	Basecase

Year	System Constraint	Circumstances
	Beech Street S/S – 1T1, 69kV-13.8kV, 22MVA Transformer – Loaded Above Normal Rating	Basecase
2045	08 Line – Lunenburg S/S to Townsend S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Lunenburg S/S to West Townsend S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Sawyer Passway S/S – 22T1 and 22T2, 69kV-13.8kV, 20MVA Transformer – Loaded Above Normal Rating	N-1 – Loss of Summer Street S/S 40T1 Transformer
	Princeton Road S/S – Circuit 50W56 Mainline Conductor – Loaded Above Normal	Basecase
2046	River Street S/S – 25T1, 69kV-13.8kV, 14MVA Transformer – Loaded Above Normal Rating	Basecase
2047	Beech Street S/S – Circuit 1W2 Mainline Conductor – Loaded Above Normal	Basecase
2049	Lunenburg S/S – Circuit 30W31 Mainline Conductor – Loaded Above Normal	Basecase
	West Townsend S/S – Circuit 39W18 Mainline Conductor – Loaded Above Normal	Basecase
2050	08 Line – Summer Street S/S to Pleasant Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 09 Line from Summer Street to West Townsend
	09 Line – Summer Street S/S to Pleasant Street S/S – Loaded Above Emergency Rating	N-1 – Loss of 08 Line from Summer Street to Townsend
	Townsend S/S – Circuit 15W16 Mainline Conductor – Loaded Above Normal	Basecase

Table 44 – System constraints from 2035-2050

With the exception of distribution mainline circuit conductors this review did not include the evaluation of other distribution equipment. Although significant upgrades should be anticipated on the distribution circuits themselves, the scope and timing of these upgrades will be more dependent on the physical location of load and which of the upgrades have been implemented at the time.

The projects detailed below address the identified constraints are based on a holistic plan to serve its customers through 2050 and beyond. The timing and need for these projects will be evaluated on an annual basis and work on these projects will only commence when load forecasts and/or planning efforts determine they are needed.

Given the extent of the electric system upgrades required to meet the forecasted load levels consideration should be given to a possible change in distribution circuit operating voltage in some or all areas from 15kV to higher voltage such as 35kV, similar to what was done decades ago during the last great electric system load increase when many circuits were converted from 4kV to 15kV.

9.2.1 Establish 2nd Circuit at Rindge Road - 2035

The loading on circuit 35W36 is forecast to exceed planning criteria in 2035. This project will reconfigure circuit 35W36 at Rindge Road S/S and establish a second 13.8kV circuit. The new circuit terminal will consist of a circuit recloser and set of voltage regulators. A second circuit is designed to improve reliability in addition to add capacity to the area.

9.2.2 Townsend Substation Capacity Additions - 2036

Townsend substation capacity will be increased. Construction will include the installation of two 30MVA (or larger), 69kV to 13.8kV transformers with LTCs and the removal of the existing 10.5MVA unit. Two 13.8kV circuit positions will be added, bringing the total number of circuits to six, three supplied via each transformer.

Distribution work will be performed to split circuit 15W16 and to extend a second circuit towards Ashby to allow for the temporary transfer of load from West Townsend S/S to Townsend S/S, deferring the West Townsend S/S 39T1 transformer loading constraint from to approximately 2045.

9.2.3 Replace Princeton Road 50T3 Transformer - 2035

The loading on Princeton Road 50T3 transformer is forecast to exceed planning criteria in 2035. Replace the Princeton Road 50T3 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

9.2.4 Install New Circuit and Split Circuit 22W1 - 2036

Install a new circuit from Sawyer Passway S/S to Mount Vernon Street. The new circuit will serve 22W1 loads from Sawyer Passway up to and including Mount Vernon Street and 22W1 will continue to serve loads beyond Mount Vernon Street. An alternative to this project is to reconductor underground portion of the 22W1 mainline.

A review of existing conduit and required new conduit and vaults will need to performed to determine the extents of both options

9.2.5 Flagg Pond Capacity Additions - 2037

Installation of additional capacity at Flagg Pond S/S. This includes the replacement of the two existing Flagg Pond transformers as well as the spare transformer with 115kV-69kV, 200MVA transformers with LTCs. This project will also include the upgrade of the 69kV bus and breakers to accommodate the additional transformer and line capacity.

A variation of this project is to install a third 100MVA, 115kV to 69kV transformer with LTC and replace the existing three transformers with LTC units. Modifications to both the Flagg Pond 115kV and 69kV ring buses would be required to accommodate a third transformer.

The decision between an additional transformer vs larger transformers will require detailed design and technical review to evaluate equipment requirements, availability and design and protection considerations.

Installing additional capacity at Flagg Pond is currently being proposed in 2037 rather than the new Lunenburg/Summer Street Area Supply below as it allows the Company to distribute spending between years while working towards the Lunenburg/Summer Street Area Supply.

9.2.6 Replace Princeton Road 50T3 Transformer - 2037

Replace the Princeton Road 50T3 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

9.2.7 Pleasant Street Substation Capacity Additions - 2038

Pleasant Street substation capacity will be increased. Construction will include the installation of a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC and populating the fourth circuit position at Pleasant Street S/S.

Distribution work will be performed to distribute load between the four circuits and the two transformers.

9.2.8 01 and 02 Line Capacity Additions - 2040

The 01 and 02 lines from Flagg Pond substation to Summer Street substation will be rebuilt with larger conductor (something larger than is typically utilized by FG&E). The summer Street 69kV bus including the 01 and 02 breaker positions would be upgraded to accommodate the additional capacity.

These lines will be constructed in a “double-circuit” configuration to accommodate future 115kV transmission lines (one each pole) between Flagg Pond and a new Lunenburg/Summer Street area substation in the future.

Similar to the Flagg Pond S/S upgrades above the reconductoring of the 01 and 02 lines is currently being proposed opposed to the new Lunenburg/Summer Street Area Supply below. This allows the Company to distribute spending between years while working towards the Lunenburg/Summer Street Area Supply.

9.2.9 Summer Street Substation Capacity Additions - 2040

Summer Street substation capacity will be increased. Construction will include the installation of two 30MVA (or larger), 69kV to 13.8kV transformers with LTCs and the removal of the existing 35MVA unit (due to anticipated condition concerns).

The Summer Street 69kV bus will need to be modified to accommodate the second transformer as well as a future sixth 69kV line.

This will set the stage for the future removal of the 1303/1309 lines to accommodate two additional 13.8kV distribution circuits.

9.2.10 Construction New Lunenburg/Summer Street Supply - 2042

Construct a new 115kV to 69kV supply substation in the vicinity of the Lunenburg Tap. Construction to include the installation of three (one spare) 200MVA, 115kV to 69kV transformers with LTC, a 115kV bus and a 69kV bus. The 115 kV bus will accommodate the two 115kV supply lines and two transformer taps. The 69 kV bus will accommodate the two transformer taps and six 69kV lines.

The 115 kV bus will be supplied via two new 115kV lines constructed from Flagg Pond substation to the new supply substation. The new lines will be overbuilt on the existing 01/02 lines and 08/09 lines. The 01/02 and 08/09 will remain and supply the existing distribution substations at 69kV. The Flagg Pond 115kV bus will need to be expanded to accommodate the two new 115kV lines.

The 69kV bus will serve the 08 and 09 lines towards Summer Street substation, the 08 and 09 lines Lunenburg Tap and the 08 and 09 lines towards Townsend and West Townsend.

9.2.11 Beech Street Tap Substation – 2042

Construct a new 69kV to 13.8kV substation in the vicinity of the River Street Tap. Construction to include a 69kV bus with two incoming lines, four outgoing lines and two transformer taps. Two 30MVA (or larger), 69kV to 13.8kV transformer will be installed to supply four 13.8kV circuits.

Two of the 13.8kV circuits will head west towards the Massachusetts Turnpike to supply portions of the Princeton Road and River Street circuits. The two other circuits will head north and east to supply portions of River Street and Canton Street substation load.

9.2.12 New Rindge Road and Ashby Area Substations – 2044

Construct two new 69kV to 13.8kV substations. One substation will be constructed at Rindge Road Tap and will consist of one 30MVA (or larger), 69kV to 13.8kV transformer with LTC and four 13.8kV circuit positions.

The second substation will be constructed in the vicinity of the Main Street/New Ipswich Road intersection in Ashby. This substation will consist of two 30MVA (or larger), 69kV to 13.8kV transformers with LTC that supply six 13.8kV circuits.

In order to supply these two substations a 69kV line “loop” will need be installed between River Street substation and Wallace Road (along City/Town Road or in ROW), Wallace Road and Rindge Road (existing 1341 will be converted to 69kV), Rindge Road and Main Street/New Ipswich Road ((along City/Town Road or in ROW) and between Main Street/New Ipswich Road and West Townsend S/S (along City/Town Road or in ROW).

To accommodate the new 69 kV line the 09 line from Lunenburg to West Townsend will be reconductored and the West Townsend 69kV bus will be reconfigured to accommodate the new line.

9.2.13 Replace Lunenburg 30T1 Transformer - 2044

Replace the existing Lunenburg Street 30T1 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

9.2.14 Construction 2nd 69kV Line between Summer S/S and Sawyer Passway - 2045

Construct a 2nd 69kV sub-transmission line between Summer Street substation and Sawyer Passway substation. The new line will be constructed in place of the existing 1303 and 1309 lines.

This will provide four additional 13.8kV circuit positions in the “central” Fitchburg area, two at Sawyer Passway substation and two at Summer Street substation.

9.2.15 Canton Street Substation Capacity Additions - 2047

Canton Street substation capacity will be increased. Construction will include the installation of a new 30MVA (or larger), 69kV to 13.8kV transformer with LTC. Construction to include the installation of a fourth circuit position at Canton Street S/S.

9.2.16 Replace River Street 25T1 Transformer - 2048

Replace the existing River Street 25T1 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

9.2.17 Replace West Townsend 39T1 Transformer - 2050

Replace the existing West Townsend 39T1 Transformer with a 30MVA (or larger), 69kV to 13.8kV transformer with LTC.

9.3 NON-WIRES ALTERNATIVES – IMPACT ON SUBSTATION DEFERRAL

Project evaluation is an integral component of maintaining a cost-effective system that ensures safe and reliable electric service. A consistent process and documentation criteria for project evaluation is required for the success of the planning process.

In 2019, the Company developed a process to evaluate non-wires alternatives for projects exceeding $500,000 in cost that are identified on the distribution or sub-transmission systems and/or within a substation and have a required construction start date within the next three to five years. This timeframe is used for two different reasons. First, project design, siting, and equipment purchase takes 3-5 years to complete. Second, it can take three or more years to develop, evaluate and implement non-wires alternatives.

This procedure does not apply to projects being justified based on condition replacement or reliability benefit only. It also does not apply to customer-requested projects such as DG interconnections, line relocations to accommodate customer requests, and the installation of new developments. However, this procedure does apply to loading and/or voltage driven projects that are required due customer requested projects.

The Company has successfully implemented one non-wires project. In 2021, the Company installed an energy storage and management system at its substation in Townsend, Massachusetts to help maximize the efficiency of renewable energy and lower costs in the region. It took approximately two years to design and install the lithium batteries and operating system, which fill one tractor-trailer sized and another smaller container. The Battery Project was designed to use the energy stored at the substation in Townsend to reduce load during key hours of the day. The battery also enabled the Company, and by extension the community, to avoid the need for future expensive upgrades at the substation level. This first of its kind project for the Company demonstrated the Company's dedication to its customers and the environment by advancing the Commonwealth's critical environmental and energy goals. The Battery Project was designed, in part, to align with Massachusetts' goal of installing energy storage systems throughout the electric grid in the Commonwealth. The project is supported by a grant from the Massachusetts Clean Energy Council.

The batteries can power up to 1,300 homes for two hours, which represents two percent of the Company's electric needs for the entire service territory in the state. Customers benefit from the Battery Project because it manages the electricity with real-time adjustments to both voltage and direction in order to maximize the efficiency of renewable energy in the region. Meanwhile, the battery in the substation is charged and ready to deploy its load at peak usage times, which is designed to lower electric costs for the Company's customers. By taking advantage of advanced software, storage capacity and the renewable energy from homeowners and businesses, the Company's Battery Project helps customers save effortlessly, which is a cornerstone in the Company's vision of a smarter energy future.

The Company will continue to manage and maximize the benefits of the EE program. Targeted spending and properly designed demand response programs may be effective to der system improvements in the future. Time varying rate structure facilitated by the AMI system will enable innovative rate designs that enable customer to manage either own usage and incentive a shift in demand away from system peaks.

The Company will continue to implement the procedure for reviewing non-wires alternatives for projects that exceed the thresholds using the process shown below:

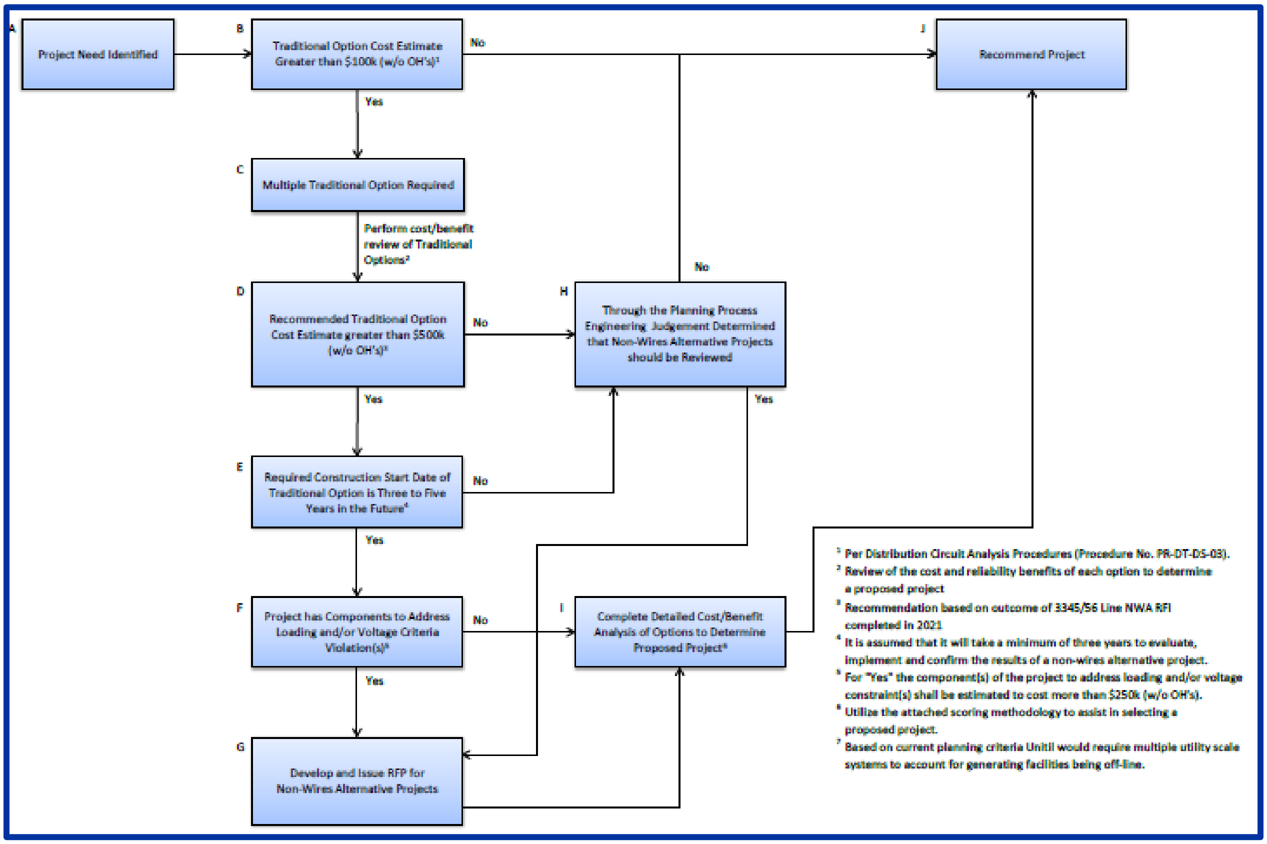

Figure 19 – NWA Project Evaluation Procedure

9.4 SYSTEM OPTIMIZATION – IMPACTS ON ELECTRIFICATION DEMAND

As explained above, the load forecast presented in this Plan shows distribution system loads increasing by 3 to 4 times by 2050. Advanced system planning tools will integrate the benefits of distributed energy resources and identify locations where these assets can be optimized. Unitil is investing in tools, including (but not limited to) DERMS, AMI, ADMS, and VVO, that will enable the Company to actively optimize the distribution system as well as provide customers the information and incentives to control and optimize their energy usage. For example, ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner; DERMS functionality can be used to control and optimize small localized segments of the electric system or entire feeders at a time. AMI will provide timely and accurate data to support various system, customer, and market facing technologies, as well as grid facing functions such as distribution management, system planning, and system optimization. Unitil will continue to implement and build upon these foundational investments to enhance system optimization and ensure a safe and resilient system that is prepared to meet the demands of increased DER and electrification.

9.5 ALTERNATIVE COST-ALLOCATION AND FINANCING SCENARIOS – IMPACT ON INVESTMENTS

As explained previously, the quantity and size of the DER interconnections on the Company's distribution system have not, at this time, driven the need for group studies or the implementation of a CIP project funding framework.

In the future, should the Company find the need to conduct a group study that results in significant capital investment, the Company proposes to apply the CIP approach approved by the Department in in D.P.U. 20-75-B. Any new CIP proposal would be evaluated on a case-by-case basis and submitted to the Department for review and approval.

9.6 ENABLING THE JUST TRANSITION THROUGH POLICY, TECHNOLOGY, AND INFRASTRUCTURE INNOVATION

Unitil's Massachusetts service territory has a significant proportion of low income households, and a high concentration of EJ communities. In particular, the Massachusetts Executive Office of Environmental Affairs has designated 90.9 percent of the Block Groups within the City of Fitchburg as EJ communities, and approximately 86.3 percent of the total population within the City reside within an EJ Block.[45] Approximately 65 percent of Unitil's Massachusetts customers are located within the City of Fitchburg, and as such Unitil's ESMP investments will be largely concentrated in designated EJ communities. As explained throughout this Plan, the Company will work with communities in its service territory in a transparent and engaged manner to ensure that EJ communities receive the full technological and environmental benefits of the Plan.

9.6.1 Aggregation of all clean technology incentives (in respective scenarios) focused on EJ communities

The Company attempts to design projects and programs that all customers can participate in. As explained above, Unitil's ESMP investments will be largely concentrated in designated EJ communities. The Company will engage with EJ communities on rate offerings, EE programs and to educate them on electric sector modernization.

[45] https://s3.us-east-1.amazonaws.com/download.massgis.digital.mass.gov/shapefiles/census2020/EJ%202020%20updated%20municipal%20statistics%20Nov%202022.pdf

9.6.2 Discussion of potential to use incentives and dis-incentives to align with distribution upgrades

Distribution upgrades in this Plan are primarily driven by load growth. These upgrades will benefit to the overall reliability, resiliency and hosting capacity of the system but are justified on loading constraints.

Innovative rate designs afford customers the opportunity to adopt new technologies, manage energy consumption, and enhance efficient utilization and consumption of electricity to save money. Such designs can also incentivize customers to strategically reduce usage and thereby help to manage or mitigate loads during peak times. The Company's AMI, MDMS, and CIS systems provide the tools required to provide timely and accurate metering data for many different types of innovative rate designs, incentivizing and allowing customers to make informed energy choices. The implementation of a data sharing platform will further enhance the utility of these designs.

Such designs can also incentivize customers to strategically reduce usage and thereby help to manage or mitigate loads during peak times. The Company's AMI, MDMS, and CIS systems provide the tools required to provide timely and accurate metering data for many different types of innovative rate designs, allowing customers to make informed energy choices. The implementation of a data sharing platform will further enhance customer use of metering data. Rate designs should incentivize customers for reducing the loads during certain periods of time. Another approach is for the company to control an aggregated grouping of loads or generation resources and compensate customers for participating in the program through a demand response program.

9.6.3 Potential incentive allocation movement among clean technologies ultimately flowing toward disadvantaged communities

The Company attempts to design projects and programs that provide benefits and participation opportunities to all customers. Unitil's ESMP investments will be largely concentrated in designated EJ communities. The Company will engage with EJ communities on rate offerings, EE programs and to educate them on electric sector modernization.

9.7 NEW TECHNOLOGY PLATFORMS

The foundation of any new technology is data. Investments in AMI infrastructure will increase the granularity and timeliness of data. Sharing that data with the customer will be important. In the 2035-2050 timeframe, the Company expects a high penetration of home energy management systems in constant communication with the utility. Customers will control their entire home from their smart phone and will need data to do so. Metering technology will continue to advance and the Company will enable this technology for our customers.

The Company is implementing customer focused tools and programs to improve customer engagement and experience. The Company is currently implementing several customer tools within grid modernization to provide the customer added control over their energy usage. The company is committed to continuous improvement in the customer experience and will continue to improve its customer marketplace and customer portals to facilitate new tools and technology.

Cyber security will become increasingly important. The overall security of the electric system and the system that run the electric system is a top priority. Increased data sharing and control functions may place added stress on the Company’s cyber security controls and systems. The Company will continue to build upon its current cyber security program to increase the monitoring of the electric system and computer networks.

The reliability and resiliency of the system will always be a focus of the Company. Technology improvements will be implemented to reduce the frequency and duration of outages. Replacement of aging equipment with newer and more efficient equipment will ensure the system continues to be operated in a safe and reliable manner. Continued installation of targeted spacer cable, targeted undergrounding and distribution automation will also reduce the frequency and duration of outages.

10 RELIABLE AND RESILIENT DISTRIBUTION SYSTEM

10.1 REVIEW OF THE COMMONWEALTH'S CLIMATE ASSESSMENT AND HAZARD MITIGATION AND CLIMATE ADAPTATION PLANS

In September, 2018, the Commonwealth of Massachusetts released its first Hazard Mitigation and Climate Adaption Plan[46]. This plan, developed in response to the Governor's Executive Order 569[47] on climate change, integrates climate change impact with strategies to address the risks associated with climate change. The Commonwealth is currently updating the plan with an expected release of fall 2023.

The plan forecasts projected changes in extreme weather events, precipitation, sea level rise and temperature and develops strategies to reduce the risks associates with climate change. Changes in precipitation can cause inland flooding, drought and landslides. Sea level rise can cause coastal flooding and erosion. Rising temperatures can cause increasing average and extreme temperatures, wildfires and invasive species. Climate change can also create more frequent and more severe hurricanes and tropical storms, severe winter storms such as nor'easters, tornadoes and other severe weather.

The risk assessment identifies the vulnerability to climate change is a function of exposure, sensitivity and adaptive capacity[48]. The plan includes a strategy and action plan to reduce the risks associated with climate change and the improve the resilience of the Commonwealth to climate change.

The Company has identified many of the same risks to our infrastructure as are identified in the State's plan. Increases in the severity of storms can cause more damage and increased outage duration for the electric system. Inland flooding, if severe enough, could damage equipment in substations and create travel problems for crews trying to restore outages. Rising temperature can cause electric load to increase and equipment ratings to decrease all resulting in more

[46] https://www.mass.gov/info-details/massachusetts-integrated-state-hazard-mitigation-and-climate-adaptation-plan

[47] https://www.mass.gov/executive-orders/no-569-establishing-an-integrated-climate-change-strategy-for-the-commonwealth

[48] See 2018 Massachusetts State Hazard Mitigation and Climate Adaption Plan, Executive Summary, Page 7.

frequent equipment failures. The Company goes into further description of its climate assessment review in section 10.4.

10.2 DISTRIBUTION RELIABILITY PROGRAMS

The Company takes a comprehensive approach to reliability and resiliency planning and is as important as traditional load flow or circuit analysis planning. Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Projects and programs are designed and implemented to: 1) eliminate the outage from occurring or 2) minimize the impact of an outage by reducing the number of customers affected and/or the duration of time they are affected for. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every sustained outage on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or other resiliency measures to reduce the size or duration of the outage. Typically, this review results in protection or construction modifications or targeted out of cycle trimming activities.

Weekly – Internal reports on overall company and individual operating center reliability performance compared to annual goals and past history are developed on a weekly basis. This review is used to track the current year reliability and resiliency performance and benchmark it against company goals and historical performance.

Monthly – On a monthly basis, the Company summarizes the significant outages – outages that account for 75,000 customer-minutes of interruption or more, that occurred in each of the operating companies over the past month. The analysis also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages caused by failures of company equipment. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report (“SER”) – At the discretion of the Company’s executive team any outage can have an SER report completed. An SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically, an SER recommends action items that are assigned and completed.

Annual – The Company conducts analysis on an annual basis that is focused upon the overall reliability and resilience performance of the system for a 12 month period. The reports evaluate individual circuit performance over the same time period. These reports are developed per Unitil's Reliability Analysis Guideline and include:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to SAIDI and SAIFI;
- Analysis of the effect of sub-transmission and substation outages on circuit performance;
- Analysis of the worst performing distribution circuits over the reporting period;
- Analysis of the major causes of sustained interruptions;
- Analysis of performance issues on specific circuits as well as recommendations for improvement;
- Analysis of equipment failures to identify trends and provide recommendations when necessary;
- Analysis of areas with multiple tree related outages for consideration for additional tree trimming; and
- Analysis of devices that have operated on more than three occasions over the timeframe.

Reliability improvement projects are designed and estimated. Each of the projects is compared based upon a cost per saved customer-minute and saved customer-interruption basis. These projects are submitted for capital budget consideration. The funding level for projects strictly justified on reliability improvement is approximately $1 million. Typical projects include: addition of reclosers or sectionalizers to decrease the outage zone, targeted spacer cable, circuit ties, and automation schemes to isolate and restore load.

The reliability planning process described above has proven very successful. The historical reliability performance for the system is outlined below.

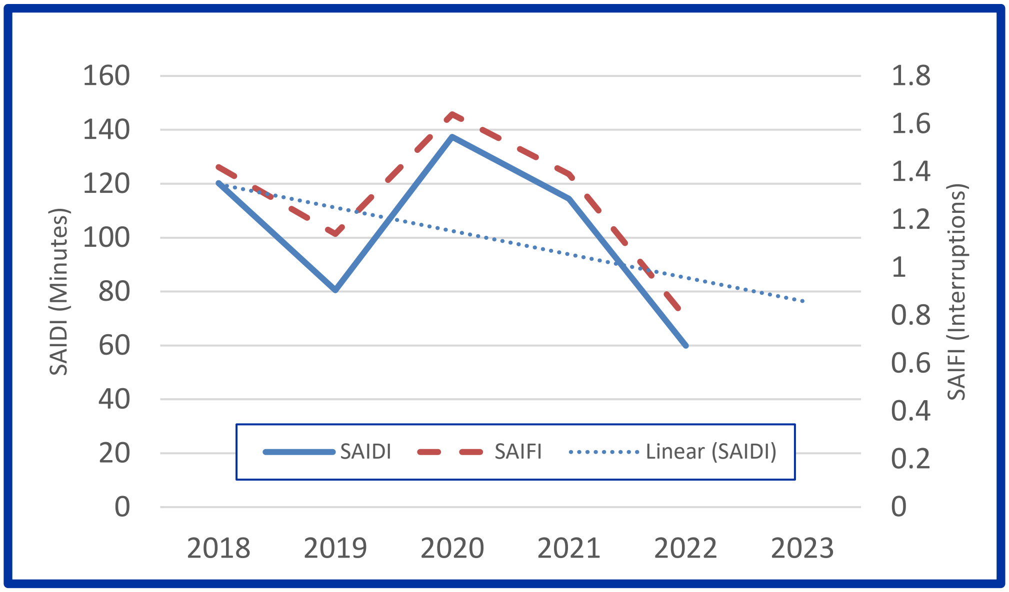

Figure 20 – Reliability Performance

The chart above displays annual SAIDI and SAIFI using Massachusetts DPU exclusionary criteria. The 2022 reliability performance was the best performance in over 25 years. The system SAIDI of 59.9 minutes is roughly 33% lower than the 10 year average of 89.8 minutes. The system SAIFI for 2022 was 0.79 interruptions which was the best performance in over 25 years. The system SAIFI was approximately 36% lower than the 10 year average of 1.23 interruptions.

The Company's vegetation management program (including its cycle pruning and Storm Resiliency Program described in the following section) has a large impact on the reliability performance of the company. The Company is experiencing improved performance during both blue sky as well as major outage situations. The vegetation management program is resulting in less damage during storms allowing the Company to consistently complete restoration ahead of neighboring utilities and send line resources to assist others with restoration. The Company continues to evaluate the program for improvements where practical.

Distribution and Sub-transmission Pole Replacements

In order to ensure the safe operation of the electric distribution system, regular inspections of the distribution and sub-transmission poles must be made to ensure a strong and resilient pole plant. On a ten-year cycle, wood distribution poles in the DOC's maintenance area shall be visually inspected and tested at and below grade level to determine the soundness of the wood. The initial inspection of poles shall take place at or before the pole age of twenty (20) years.

Two of the most destructive forces affecting wooden poles is decay and loss of cavity. These will generally progress at a predictable rate and the advancement of decay can be readily diagnosed in the field at all but the very early stages. Detection of decay, loss of cavity, or damage is essential in establishing the remaining pole life.

Unitil utilizes a resistograph to perform pole testing. The resistograph, is a non-destructive test device that determines the decay and cavity degree of the poly by capturing the resistance of the constant force of a special micro-drill bit as it travels through the wood of the pole. This allows the user to identify soft spots and voids inside the wood. A corresponding graph is produced that shows the depth (inches and cm) and changes in density according to resistance providing a profile of the pole. Data from this device is utilized in various computer models to determine the strength of the pole.

Currently, an electronic field mobile tablet is utilized in conjunction with web-based software to record and retrieve information for the majority of the aforementioned inspections. This software links directly to the Company's internal record data bases. The results of all cycle inspections and tests and corrective actions taken are recorded and retained for one complete cycle but not less than a period of six years. Inspection reports identify all poles/equipment inspected. All non-compliant findings are noted indicating corrective action to be taken and close out date (i.e., when corrective action was completed). Poles are prioritized for replacement based the resistograph and visual inspections.

Emergency Response Plan

Even the most successful reliability and resiliency program will not eliminate all outages. The Company’s Emergency Response Plan is designed to be a guide for the activation of the Electric Emergency Response Organization. Its purpose is to ensure the effective implementation and coordination of the corporate emergency response actions during an Emergency Event. The ERP utilizes the National Incident Management System which is a comprehensive national approach to incident management applicable at all jurisdictional levels and across functional disciplines.

The ERP also addresses the operation of the Emergency Operations Centers. The plan remains focused on public safety, workforce safety and safety of outside aid and is designed for the reasonably prompt restoration of service during an Electrical Emergency Event.

The ERP addresses electric emergency response to customer outages caused by weather (e.g. thunderstorms, hurricanes, tornadoes, extreme heat, storm surge, river flooding) other natural or man-made causes (e.g., major equipment failure, civil unrest, terrorism, wildfire, etc.), or disasters causing significant customer interruptions and is predicated on knowing and understanding the magnitude of the event. The ERP is in accordance with all applicable regulations and is designed under the Incident Command System and Unitil's Crisis Response Plan.

10.3 DISTRIBUTION RESILIENCY HARDENING PROGRAMS

Comprehensive Vegetation Management Program

The tree density in the Company's service territory is in the upper quartile of tree densities (137 trees per mile) when compared to other utilities throughout the United States, which is an average 96 trees per mile. The Company has experienced a decline in forest health and the trees within its service territory. Trees in Massachusetts have been subjected to several environmental stressors in recent years, including the emerald ash borer, spongy (formerly gypsy) moths and white pine needlecast, which can lead to increased tree/limb fall during both blue sky days and severe weather events.

Given the environmental stressors and weather events and the impact they have had on the tree population in Massachusetts, the Company has long been focused on vegetation management activities to address those impacts. As part of its mandate to provide safe and reliable service to its customers, the Company has consistently taken proactive steps to enhance and protect its distribution system from vegetation impacts using a two-pronged approach: its annual vegetation management activities and the Storm Resiliency Program ("SRP"). These programs are critical given that the Company's system infrastructure is unavoidably exposed to many different weather events, like ice storms and heavy wet snow, such as the January 2023 winter storm, that can cause substantial damage and prolonged power interruptions. To combat this, the Company relies on a comprehensive vegetation management program that is designed to prevent trees from interfering with electric lines during normal weather conditions and minor storm events. The program's components cost-effectively address the different areas of risk and provide benefits to customers, support favorable reliability, and provide a measure of public safety. The Company has made several modifications to the vegetation management program in recent years to optimize the benefits of the program while ensuring that the Company retains the necessary flexibility to direct the program in a manner that benefits customers.

Additionally, the Company has, since 2014, utilized the SRP to mitigate and eliminate system-level severe weather event vegetation risks that could otherwise negatively impact the system, and customers, during these events. Under the SRP, the Company has made significant progress in reducing tree exposure along electric overhead lines in order to reduce the overall cost of storm preparation and response and improve system resiliency during major storm events.

The Company's comprehensive vegetation management program consists of three main components: cycle pruning; hazard tree mitigation; and forestry reliability assessment. Each component of the program is designed to minimize the potential for tree and vegetation contact with the overhead utility lines and the incidence and resulting damage of tree and limb failures from above and alongside the conductors.

Vegetation maintenance pruning and clearing done on a cyclical schedule by circuit is called "cycle pruning". The Company's base cycle length is five years. The Company has recently transitioned from a four-year cycle to a five-year cycle based on the need to focus efforts and resources on increased hazard tree removals. This decision was driven, in large part, by the decline in forest health and increase in tree mortality. The move to a five-year cycle allowed for resources to become available to undertake a cycle pruning mid-cycle assessment, to identify and address any emergent vegetation issues, and perform additional hazard tree removal. Under these mid-cycle assessments, the Company visually inspects every transmission and distribution line at least every three years to ensure that no areas of the distribution system are left unattended. If the Company encounters any vegetation issues while conducting the mid-cycle assessments, such as hazard trees that warrant removal to avoid impacts to the system, the Company addresses the issue in the near term, rather than waiting until the start of the next five-year cycle. By undertaking these mid-cycle assessments, the Company proactively addresses potential vegetation issues cost-effectively.

The vegetation management program has a non-discretionary or "Core Work" component. This critical component of the vegetation management program enables the Company to respond to emergencies, customer requests, new construction needs, and other non-discretionary and unscheduled work. A dedicated number of specialized crews are required on site on a year-round basis to address the Company's Core Work needs.

A hazard tree is a danger tree (any tree which, on failure, is capable of interfering with the safe, reliable distribution of electricity) that has both a target and a noticeable defect that increases the likelihood of failure. The hazard tree mitigation component program involves the consolidation of hazard tree removal activities into a formalized program to drive both operational and cost efficiencies. As noted above, hazard trees can be identified during the five-year pruning cycle or as part of the mid-cycle assessments. Additionally, the Company can identify, based on field conditions including incidents of past tree failure and/or poor performing circuits ("PPC"), targeted hazard tree mitigation assessments where a more intensive hazard tree inspection is necessary. These assessments include a more detailed visual tree assessment and a wider scope of assessed trees. This more intensive inspection generally leads to an increased number of hazard trees to be removed per mile. No matter the how the hazard trees are identified, the Company takes the same steps to prioritize, and efficiently and effectively remove these trees before they can impact the system and customers.

The forestry reliability assessment program component targets circuits for inspection, pruning, and hazard tree removal based on recent historic reliability performance. Identifying and addressing PPC or circuits that could become PPC in this manner gives the Company the flexibility to quickly react to and address immediate reliability issues, rather than waiting for the circuit to be addressed as part of mid-cycle or the five-year maintenance cycle.

The Company has designed the integrated components of the vegetation management program to meet the Commonwealth's regulatory targets and expectations and increase customer satisfaction through improved reliability performance. In addition to these overall goals, cycle pruning also provides a measure of public safety by minimizing the potential for public direct contact with downed wires as a result of failing trees and limbs, with energized conductors by climbing trees and indirect contact though vegetation in contact with energized equipment, as well as minimizing the potential for electrically caused fire in trees and brush.

The Company has a sub-transmission maintenance component that applies the principles and practices of integrated vegetation management ("IVM") to maintain the rights-of-way. This includes identifying compatible and incompatible vegetation, considering action thresholds, evaluating control methods and selecting and implementing controls to achieve a specific objective. The plants to be controlled are primarily tall growing trees that can grow into or fall onto electric lines. Right-of-way maintenance includes: cyclical floor maintenance, such as mowing, hand cutting, and herbicide application; side line pruning; and hazard tree removal.

The Company has developed a vegetation management contract strategy to strive for the lowest market price and minimize the program components' costs where possible. This was done by first outlining the vegetation management goals and strategies for delivering work and minimizing risk and associated cost, and then by listing the contract methods and types available for award of work to qualified line-clearance vendors. The strategy multiple vendor Lump Sum Fixed Price Bid, Unit Price Bid award, as well as single vendor three-year contract "time and material" award. The Company carefully balances the benefits of a longer-term contract with the need to respond to market pricing to attract and retain skilled workers.

The Company has also implemented an evaluation program that tracks vendors' work and progress, including progress in meeting Company expectations and key indicators. Their performance is one of the factors considered when the Company is procuring services. Utilizing this performance evaluation program as an indicator of future work assists in workforce retention while ensuring that customers are benefitting from high quality, consistent work that enables the Company to continue to provide safe and reliable service.

Storm Resiliency Program

The increase in significant, severe weather events impacting the service territory and the Company's customers was the main impetus behind the introduction of the SRP. In 2011, the Company was impacted by two significant weather events that affected the Company's service territory, Hurricane Irene and the October Snowstorm, where over two feet of snowfall was recorded in Massachusetts. The 2011 October Snowstorm caused widespread damage and prolonged outages and was the second largest event in the Company's history. In 2012, Hurricane Sandy impacted the Company's service territory and customers. Prior to 2011, the Company's system had also sustained damage due to other frequently occurring storm events. In addition, there are comprehensive and stringent statutory and regulatory requirements for all distribution companies in the Commonwealth that increase the standards and obligations for storm preparedness and response.

In the interest of customers, the Company recognized the need to proactively address the situation and began to explore the options available to "harden" or make critical elements of the system more resilient to storms. After the review of different options available, such as undergrounding electric lines, and reviewing rough cost estimates, the Company recognized that there was an opportunity to implement a vegetation-centered storm hardening program that would provide customer benefits at a lower cost than other alternatives.

The SRP differs from the vegetation management program in that it is designed to reduce tree exposure along select circuits in order to improve performance during major storm events. The goal of this program is to reduce tree-related incidents and the resulting customer interruptions, as well as impacts to municipalities, including identified critical facilities such as hospitals and police and fire stations, along critical portions of targeted lines in minor and major weather events. In turn, the Company has implemented the SRP in a manner designed to reduce the overall cost of storm preparation and response, improve restoration, and preserve municipal critical infrastructure for the purpose of enhancing public health and safety.

Under the SRP, critical three-phase sections of select circuits, defined as the circuitry from the substation out to a desired protection device, undergo tree exposure reduction by: (i) removing all overhanging vegetation, or pruning "ground to sky;" and (ii) performing intensive hazard tree review and removal. In addition, under the SRP the remaining three-phase circuitry beyond the designated critical portions undergoes hazard tree review and removal. In selecting the portions of circuits to include in the SRP, the Company takes into account the critical infrastructure needs of the towns and cities served by the circuits. The locations of police and fire departments, schools, emergency shelters and other critical business centers are therefore considered along with the critical electric infrastructure when selecting the circuits.

Based on recent analysis, the SRP is providing definite reliability benefits to customers and there is a clear improvement trend in SRP circuit performance for SAIDI, SAIFI, and CAIDI as compared to the non-SRP circuit performance. Specifically, under storm conditions, the SRP circuits substantially outperformed the Non-SRP circuits. Given the benefits to customers, it is critical that the Company continue to implement the SRP to avoid a loss of those benefits.

The SRP was designed to prevent tree-related failures and attendant customer outages by implementing the comprehensive activities described above, which would in turn improve reliability, improve customer service and satisfaction, reduce safety risks, and avoid preparation and restoration costs during storm events. In developing the SRP, the Company also determined that there were additional benefits that were expected to materialize, including:

- Preserving municipal critical infrastructure;
- Minimizing the dependence on mutual aid and off system resources;
- Minimizing the total number of resources required to restore service;
- Shortening the duration of major events;
- Minimizing the overall cost of restoration;
- Reducing economic loss to municipals, businesses, and customers; and
- Most cost-effective solution versus other alternatives.

The Company consciously selected SRP work areas that included much of a municipality's critical infrastructure. These areas are also most often the business centers for the municipality, and therefore include gas stations, restaurants and hotels. Preserving power during multiple-day weather events to both municipal infrastructure and business districts ensures that emergency services have power and are able to function and residents have options for seeking temporary warmth and shelter.

In addition, as many states and regulatory jurisdictions have established standards for restoring power during major events, the competition for securing outside line resources has increased significantly and, as a result, resources have become both scarce and very expensive. Often, in order to secure an adequate amount of resources for a particular event, the Company has been required to reach outside of the New England, adding travel time and additional cost. The SRP helps avoid these increased costs by preventing the damage from occurring in the first place. If there is less damage to the system due to fewer tree/limb falls, there will be a reduced need for outside crews, which, in turn, lowers overall storm restoration costs and shortens the duration of an event.

The Company, based on its interactions with the municipalities and businesses it serves, recognizes the significant economic impact of losing power for multiple days. These natural disasters are very disruptive, result in a loss of business income and tax revenue, personal income loss, and increased costs to municipalities due to the requirements of providing emergency services, debris removal, and requiring overtime work for multiple departments. Since the Company designed the SRP to reduce tree/limb falls that impact the system, these municipalities and businesses will benefit from a reduced number/duration of outages.

Similarly, residential customers have expressed concern with losing power for multiple days. Although it is impossible to prevent storm damage across the entire system, the SRP's focus on preserving power and minimizing damage for each municipality along its main business corridor, as well as protecting its emergency critical infrastructure, provides residential customers with a measure of security during and after these extreme weather events. Additionally, since the SRP is designed to mitigate the impact of vegetation on identified circuits, residential customers would benefit from fewer/shorter outages.

Lastly, when the Company initially began looking at ways to harden the system against the impacts of major weather events, it did consider different options, such as undergrounding electric lines. Given the significant costs associated with undergrounding distribution circuits, the SRP presented a highly effective and cost-effective method of reducing both the frequency and duration of outages.

Since implementing this program, the Company has identified a reduction in the duration of major events and a reduction in overall cost of the events, due to reduction in damage and resources required to restore service. In the early years of the SRP, the Company compared storms that had recently impacted the service territory with pre-SRP storms with similar forecasts and resulting weather to identify if the expected benefits of the SRP were being realized. While the nature, variability and complexity of storms made comparing storms a challenge, the Company did determine that there had been a reduction in damage between similar storms. For example, both the wind event of March 2, 2017 and the wind event of January 4, 2018, had sustained winds reaching 35mph and wind gusts reaching 55mph. However, the circuits that underwent SRP work in October 2017, in the time between these two storms, fared significantly better in the January 2018 storm, after the SRP work was done. The March 2017 storm resulted in 18 tree-related outages while the January 2018 storm resulted in one tree- related outage.

The Company has also determined that the reduction in damage has translated to overall event time restoration. In comparing relatively similar storms Hurricane Sandy in 2012 (pre-SRP) and the post-SRP implementation March 2017 Wind Event, and January 4, 2018 wind storm, restoration time was improved by over 24 hours, with less than half the number of crews needed to restore service. For winter storms, the results were similar. In comparing the November 26, 2014 winter storm Cato, which had 12 inches of wet snow, to the two 2023 winter storms Kassandra (January 23, 2023 - 15 inches of wet snow) and Sage (March 14, 2023 – 30 inches of wet snow) there was a 61% improvement and a 55% improvement, respectively in numbers of customers impacted plus an improvement in restoration time by 24 hours. Please see Exhibit Unitil-SMS-6 for a graphical depiction of Unitil historical restorations and a reduction in storm duration.

More recent analysis, focused on a review of outages pre- and post-SRP completion, has demonstrated that the benefits associated with SRP continue to accrue to customers. Circuits that are included in the SRP had far lower CMI per event ratios than non-SRP circuits.
A reduction in total storm costs typically has gone hand in hand with reduction of overall storm event duration. Although each storm is unique, as is the preparation for and response to the storm, the Company's analysis has determined a reduction in storm cost of $397,000 for the March 2017 storm to $25,000 for the January 2018 storm. After completing restoration on its system, the Company has also been able to provide mutual aid support by releasing additional contractors, and sending its own internal resources to assist other utilities in their restoration efforts. This has occurred on at least 11 occasions since 2019.

Distribution Circuit Ties and Automation

The ability to switch load between different sources provide a level of flexibility for day to day as well as improves reliability and resiliency during outage conditions. The Company conducts a master plan review as part of the distribution planning process. The purpose of the master plan is to provide strategic direction for the development of the electric distribution system as a whole. It does not, in and of itself, represent a cost-benefit justification for major system investments. Instead, it is intended to guide design decisions for various individual projects incrementally towards broader system objectives. The concepts detailed in the analysis are considered in all future designs of the system. It is expected that this Master Plan will be modified, adjusted, and refined as system challenges and opportunities evolve.

The master plan is used to identify the future location of circuit ties to provide the ability to switch load between substations and improve the overall reliability and resiliency of the system. The reliability and resiliency plan reviews locations where new circuit ties and automated restoration schemes would have reduced the overall size and impact of outages. Projects are evaluated and prioritized based upon 1) project cost per saved customer minute and 2) project cost per saved customer interruption.

Spacer Cable

As described above, the Company's service territory has above average tree density. The Company uses a comprehensive approach to vegetation management and SRP to address this challenge. However, the vegetation management and SRP programs rely on customer and town approvals to trim and remove trees.

The Scenic Road Act[49] is a state statue designed to protect trees and stone walls within the road right-of-way for streets that have been designated as "Scenic Roads". The Scenic Road Act has been adopted by the cities and towns within our service territory. The Scenic Road Act requires that a public hearing before the local planning board is held prior to removing a tree or altering a stone wall. The Company has worked diligently with the towns to try to obtain approval to conduct vegetation management activities along scenic roads. However, the town generally denies these requests and the Company is left to find other means.

[49] https://malegislature.gov/Laws/GeneralLaws/PartI/TitleVII/Chapter40/Section15C

The vegetation management program also relies on individual customer approvals prior to conducting vegetation management activities along a given street (i.e. non-scenic roadway). Most customers are generally receptive to allowing the Company to trim and remove trees, but some are not. The Company is left to find other means when the customer does not allow trimming activities to happen.

Spacer Cable consists of overhead wire which is covered with a tree-resistant coating and oriented in a compact diamond configuration to minimize the opportunity for trees to come in contact with or get caught on the overhead lines. This is more expensive material than bare overhead conductors. Spacer cable will allow intermittent tree contact without causing an outage. Spacer cable is an excellent option where trimming rights are not granted and the utility has an overhead corridor to install the spacer cable.

Spacer cable will not eliminate all outages. Trees that are large enough can still take the spacer cable off the pole or even break poles. The Company applies a consistent approach to spacer cable analysis when estimating the saved Customer Minutes of Interruption ("CMI") based upon past reliability performance:

- 50% savings in CMI for outages caused by animals
- 80% savings in CMI for outages caused by fallen tree limbs
- 50% savings in CMI for outages caused by fallen tree trunks
- 80% savings in CMI for outages caused by tree growth into the line
- 50% savings in CMI for outages caused by uprooted trees
- 80% savings in CMI for outages caused by vines

Targeted Undergrounding

Targeted undergrounding is a preferred option for areas of high tree density, where the Company cannot get trimming rights and spacer cable is not an option. Targeted undergrounding is generally done over several spans or up to as much as a mile. Targeted undergrounding will eliminate 100% of tree related outages since all of the cable is buried. Targeted undergrounding tends to be a more-costly option[50] than either spacer cable or bare overhead construction.

[50] Targeted underground costs can range from $4 million to $6 million per mile depending upon the complexity of the design, number of lateral taps, quantity of customers connected and the number of transformers.

However, in targeted cases, undergrounding is a good solution to improving the resilience of the electric system.

Targeted undergrounding comes with some challenges as well. Replacing an existing overhead line with an underground cable requires:

- Assignment of an underground location for the cable and conduit by the city/town;
- Replacement of all overhead transformers with padmounted transformers, which may require easements from landowners;
- Replacement of overhead services with underground services, which may require easements from landowners;
- Replacement of meter socket from an overhead entrance to an underground entrance; and
- Replacement of pole-mounted equipment (i.e. switches, reclosers, fused cutouts, etc.) with padmounted equipment, which may require easements from landowners.

Recommended Increase in Reliability and Resiliency Spending

In this plan, the Company is proposing to increase spending on its targeted spacer cable and undergrounding projects by a combined $1.0 million in an effort to increase the overall resiliency of the electric system. This level of funding will support the installation of approximately 2 miles of spacer cable or 700 to 1,800 feet of targeted undergrounding. This spending may also be used for developing circuit ties where they do not exist or automating circuit ties where they do exist.

Year	2025	2026	2027	2028	2029	2025-2029 Total
Capital Costs (000s)	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	**$5,000**
O&M Costs (000s)	$ 0	$ 0	$ 0	$ 0	$ 0	**$0**
Total Costs (000s)	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$ 1,000**	**$5,000**

Table 45 – Proposed Reliability and Resiliency Spending

Customer Benefits

Though it will significantly reduce outages, unlike targeted undergrounding, spacer cable will not eliminate all outages. Trees that are large enough can still take the spacer cable off the pole or even break poles. The Company applies a consistent approach to spacer cable analysis when estimating the saved Customer Minutes of Interruption ("CMI") based upon past reliability performance:

- 50% savings in CMI for outages caused by animals
- 80% savings in CMI for outages caused by fallen tree limbs
- 50% savings in CMI for outages caused by fallen tree trunks
- 80% savings in CMI for outages caused by tree growth into the line
- 50% savings in CMI for outages caused by uprooted trees
- 80% savings in CMI for outages caused by vines

Improving the resilience of the system also results in less damage during storm events. Less damage results in shorter outages, fewer crews and a less costly overall restoration.

10.4 ASSET CLIMATE VULNERABILITY ASSESSMENT (SUCH AS FLOOD IMPACTS, WIND SPEEDS, HIGH HEAT IMPACTS, ICE ACCRETION, WILDFIRE AND DROUGHT)

Climate-related risks and opportunities are reflected in our strategic planning processes. Operations, and operating excellence, are critical to and driven by the Company’s mission and vision, which include deliberate consideration for sustainability, and climate change risk and opportunity. The Company’s Mission “to safely and reliably deliver energy for life and provide our customers with affordable and sustainable energy solutions” recognizes the critical importance of our energy delivery services and also considers the lasting value sustainability creates for our stakeholders. The Company’s Vision Statement, “to transform the way people meet their evolving energy needs to create a clean and sustainable future” is heavily influenced by climate related risks and opportunities.

Our Strategic Planning Process includes an annual review of industry drivers, continuous improvement Mission objectives, and strategies to achieve our Vision. In 2022 Unitil's Strategic Planning Committee engaged its Strategic Management Group in a multi-day exercise to perform two separate climate scenario analyses: one that aggressively models high emissions and climate impacts to the region (RCP 8.5)[51] and one that forecasts drastically curbed emissions and a milder

[51] RCP 8.5 refers to the concentration of carbon that delivers global warming at an average of 8.5 watts per square meter across the planet. The RCP 8.5 pathway delivers a temperature increase of about 4.3˚C by 2100, relative to pre-industrial temperatures. RCP stands for Representative Concentration Pathways.

outcome (RCP 2.6)[52]. Members were asked to review scenario specific supporting data and project operational, organizational, and financial impacts in each case. SMG members were divided into groups with balanced cross functional expertise and tasked with targeting specific focus areas with the purpose of making suggestions on both risk mitigation and the pursuit of opportunities. Results were compiled, ranked by intensity across a risk mitigation 'heat map,' and reviewed to establish common themes, priorities, and alignment to the Strategic Pillars contained within the Company's existing strategic planning documents.

The results of the climate-related scenario analysis were an understanding of which physical and transitional risks under which Representative Concentration Pathways (RCPs) are material to the company, and which of these risk areas have the highest risk prioritization. Seven physical risks and 4 transitional risks for two RCP scenarios (11 total cases) were identified for company specific assessment. This assessment included identifying the likelihood and impact to the company as well as the risks, mitigating actions, and opportunities associated with each. Of those 22 cases, 6 were identified as posing the highest likelihood and impact to the Company. These were Technology; and Policy, Legal, and Regulatory under RCP 2.6 and Temperature Extremes; Hurricanes and Storms; Reputation; and Change in Mean Temperature under RCP 8.5. For each of these 6 cases, the identified risks, mitigating actions, and opportunities faced were reviewed for inclusion in current strategic planning initiatives. Each of these areas were reviewed for additional data and input need and are incorporated into an internal strategic planning project management plan to continue analysis and further inform strategic planning.

In response to the findings from this assessment, the Company will be evaluating the following:

- Evaluate equipment loading guidelines specific to loading cycle and ambient temperature to determine the impacts ambient temperature will have on the overall ratings of various types of equipment
- Evaluate overhead line design standards for increase ice accretion and wind speeds to determine the effect on the conductors, poles and other supporting equipment.
- Evaluate pole loading standards in an effort to make the system more resilient to ice and wind loading.

[52] RCP 2.6 (also referred to as RCP3-PD) is the lowest in terms of radiative forcing among the four representative concentration pathways. This particular scenario is developed by the IMAGE modeling team of the Netherlands Environmental Assessment Agency (Van Vuuren et al., 2007).

- Evaluate areas of potential inland flooding concerns (i.e. along existing rivers and streams) to determine when flood mitigation measures are required.
- Install targeted undergrounding in areas where traditional or even enhanced vegetation management activities are not successful.
- Increase the quantity of circuit ties and implement FLISR schemes to automatically isolate and restore outages.

10.5 FRAMEWORK TO ADDRESS CLIMATE VULNERABILITY RISKS THROUGH RESILIENCE PLANS

The Company is in the early stages of designing and implementing an iterative framework to assess the risks associated with climate change. The goal of the framework is to identify areas of risk, implement mitigation measures to reduce risk and improve the resilience of the system. The following high-level steps describe the framework:

1. Vulnerability Assessment - The Company's approach to address climate vulnerability and develop resilience plans begins with the climate vulnerability assessment described in the previous section;
2. Evaluate and Prioritize Risk – The Company is now at the step of evaluating and prioritizing the relative risks associated with each scenario;
3. Develop and Evaluate Mitigation Options – Once the risks have been prioritized, the next step is to develop mitigation strategies to address and mitigate the risk identified. In evaluating the mitigation options, the Company will consider and prioritize the impact the mitigation and benefit has on environmental justice communities and low to moderate income customers ;
4. Prioritize Implementation of Mitigation Options – Once the mitigation strategies are identified, each of the strategies should be prioritized and implemented in order;
5. Evaluate Success – The Company must evaluate the success of the mitigations implemented to ensure the mitigations are providing the expected improvements to reliability.
6. Repeat Vulnerability Assessment – Following the implementation of mitigation strategies, the Company must conduct the vulnerability assessment again to identify and evaluate and new or emerging threats that may not have been identified in the last assessment.

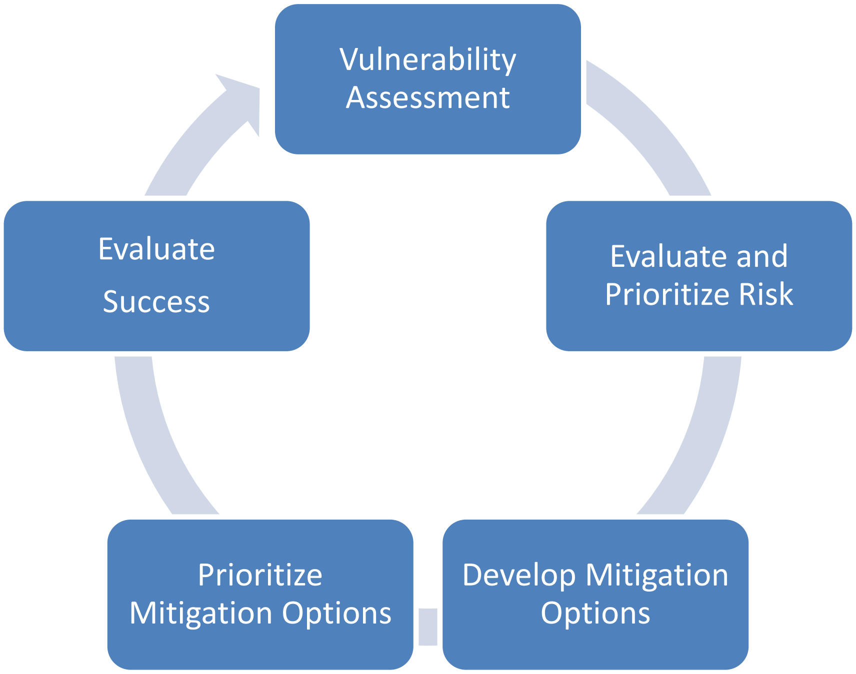

Figure 21 – Climate Vulnerability Assessment Framework

The Company, when designing the mitigation options, will consider the risk of climate change and not just past performance as an indicator of future performance. Climate change will continue and risk will continue to present themselves. The iterative framework will ensure the Company remains focused on new and emerging risks to the resilience of the system.

11 INTEGRATED GAS-ELECTRIC PLANNING

Gas and electric utilities generally plan and operate their networks in isolation from one another even when they are affiliated companies within a common parent company because historically there has been little need for coordination. Moreover, customer demand-side programs have not traditionally been closely integrated with infrastructure planning. Electrification of gas customers not coupled with the necessary electric infrastructure improvements may result in an unreliable grid. As such, the Company is evaluating integrated gas-electric planning as a tool to ensure safe, reliable, and affordable service to our gas and electric customers.

LDCs and EDCs are uniquely positioned to work collaboratively in development of electric distribution and gas infrastructure plans to meet future electrification needs. An orderly coordination and collaboration on gas and electric system planning and customer demand-side programs offers opportunities to optimize overall energy system costs and reliability. With seamless exchange of gas and electric forecasts, LDC and EDC capital investment plans can identify synergies and opportunities in the development of their capital plans. Integrated planning will help enable the Commonwealth collectively to:

a) Prudently build out the electric system in the right locations at the right time to prepare for the electrification of heating loads and
b) Make calculated decisions about where to prioritize investment in the gas and electric networks.

Integrated planning is a tactical toolkit to evaluate and shape where, why, how much, and by when to make critical investments in gas and electric networks so that gas and electric utilities have a shared plan for how to meet the heating needs of customers.

11.1 CHALLENGES IN CONSIDERING INTEGRATED GAS-ELECTRIC PLANNING

As highlighted in the prior sections, multiple areas of the electric distribution system are at or above reliability limits – which require imminent upgrades. Construction of such upgrades, especially for new substations, can take as long as 5 years or more. Similarly, multiple areas on the natural gas distribution and upstream systems have constraints imposing reliability and safety risks. The existing planning of the gas and electric systems have traditionally been bifurcated. There is now a convergence of the systems as heating and transportation sectors consider a transition to electrification. Further complicating this is that the footprints of EDCs and LDCs do not completely overlap necessitating integrated planning to be coordinated across utilities – and their associated electric and gas network upgrade plans. Key challenge areas that need to be overcome:

1. **People, Process, Technology:** While utilities have planning staff in Gas and Electric sides, their skillsets, the tools they use, the planning standards, and the overall capital planning processes across utilities and even between EDCs and LDCs are different. And this is to be expected with past practices requiring little to no coordination planning efforts even across affiliated operating companies. The first challenge in kicking off a coordinated Gas-Electric Planning process is to assess these differences through a common understanding

and drive alignment such that a foundation of a coordinated planning between the EDCs and LDCs across utilities can be established.

2. **Limited-service territory overlap**: To understand the limited degree to which affiliated gas and electric utilities' service territories overlap, it helpful to look at the share of gas customers served by the affiliated EDC since electricity service is universal. Only 28% of National Grid's gas customers are also National Grid electricity customers. Similarly, only about 50% of Eversource's gas customers are also Eversource electricity customers 86% of Unitil's gas customers are also Unitil's electricity customers. This level of overlap between gas and electric networks drives the need for coordinated utility planning..
3. **Customer adoption** Electric and Gas utilities can transform their capabilities for integrated planning with the most robust processes, software, and data for developing plans. Plans to optimize across gas and electric network investments will ensure that safe and reliable electric and gas networks are maintained for customers.
4. Integrated planning requires answering novel questions about the interplay of customer adoption/legacy building stock electrification, electricity network capacity expansion, and gas system modernization, reinforcement, or decommissioning. Today's industry standard data, tools, and planning processes are not designed to answer these questions. The preceding sections provide some early indication of potential strategies to help address these challenges.

11.2 TRANSPARENT ELECTRIC SECTOR MODERNIZATION PLAN

The ESMPs provide an important first step in enhancing the transparency of electricity network investment plans and the rationale for them among the Commonwealth's utilities. This transparency can be the basis for building out integrated planning.. This information can inform utility planning processes and pave the way for information sharing on the status of electric system plans with gas utilities. The ESMPs also create more transparency among a broader set of Commonwealth stakeholders of the immediate network investment plans for the EDCs. This information can inform the gas planning process and pave the way for some very basic information sharing on the status of the electric system plans.

11.3 COORDINATED GAS-ELECTRIC PLANNING PROCESS

Integrated energy planning will require changes to utility processes, people, and technology. More work is needed to fully detail out what a fully mature capability will require, but initial requirements would include the exchange of information and coordinated planning between LDCs and EDCs. Planning may also necessitate the implementation of software tools and incremental full time equivalent ("FTE") positions.

11.4 SAFE AND RELIABLE GAS INFRASTRUCTURE

In the near term, gas utilities have network reinforcement needs to ensure a safe, reliable and affordable system. Even more importantly, gas utilities will need to continue to make investments in maintaining safe and reliable service and reducing fugitive methane emissions, especially by replacing leak-prone pipe infrastructure. Those investments are driven in large part by current state and federal safety regulations.

12 WORKFORCE, ECONOMIC, AND HEALTH BENEFITS

Electric sector modernization will not be successful unless and until the workforce is assembled and trained. Technology is swiftly advancing and the rapid growth will increase the quantity of technical and non-technical jobs, increasing the opportunity for training and growth within the workforce.

Investments in modernizing the electric system provide workforce, economic and health benefits to customers and the communities that we service. These benefits are not limited to any particular subset of our customer base. An increase in good paying jobs at all levels of skill and education are required to modernize the electric system. A large portion of the Company's service territory is located within an EJ community. Therefore, the increase in good paying jobs will offer local economic opportunities to individuals within the EJ communities . This in turn will stimulate the local communities and spur improvements in housing and transportation that may not have otherwise been attainable within the same timeframe.

12.1 OVERVIEW OF KEY IMPACT AREAS

The Company 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, the Department and the New Hampshire Public Utilities Commission 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.

Lower GHG emissions and reduced air pollution will improve the health of our customers and communities. 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 support energy efficiency and time-of-use initiatives which allow customers to take control of their own usage, further lowering GHG emissions. We 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. Land use impacts and mitigation are considerations for every project with specific focus on the impact to EJ communities.

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

Providing safe, reliable and resilient service at an affordable cost to all customers is central to the Company's mission. As the grid continues to experience more severe weather due to climate change, building a resilient and reliable grid is critical to the future success of the communities we serve. The grid must be operated in a manner that ensures public and employee safety. Improved reliability, communications and resiliency is required to support electrification. 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.

Transportation and building electrification, energy storage and the integration of DERs 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. The grid should be designed in such a manner to avoid curtailment of renewable energy due to constraints on the system. The timely adoption and integration of renewable resources and distributed energy resources is beneficial to the environment.

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 to enable the delivery of 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. Minimizing and mitigating the impact on the ratepayers, and especially low and moderate income ratepayers, supports the overall goals of reduced greenhouse gas emissions.

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 electric 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. Promotion of energy storage and electrification technologies is necessary to decarbonize the environment and the economy.

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 are 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 create 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.

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. The table below maps the existing and proposed projects to the objectives.

Project Or Functionality	Existing / Planned	Environmentally Friendly	Safety, Reliability, and Resiliency	Customer Enablement	Security	Flexibility	Affordability	Demand and Asset Optimization	Technical Innovation
Base Capital Budget	Existing	X	X	X	X	X	X	X	X
Enable Grid Services	Planned	X	X	X	X	X	X	X	X
ADMS/DERMS	Existing and Planned	X	X	X	X	X	X	X	X
VVO	Existing and Planned	X	X	X		X	X	X	X
SCADA Automation	Existing and Planned		X	X	X	X	X	X	X
Cyber Security	Planned		X	X	X				X
FERC 2222 implementation	Planned	X	X	X		X	X	X	X
Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
South Lunenburg Substation	Planned	X	X	X	X	X	X	X	X
EV Charging and Make Ready	Existing and Planned	X	X	X	X	X	X	X	X
Targeted Reliability and Resiliency	Existing and Planned		X	X	X		X	X	X
Energy Efficiency	Existing and Planned	X		X	X	X	X	X	X

Table 46 – Mapping Projects to Objectives

12.2 JOBS TRAINING AND IMPACTS TO DISADVANTAGED COMMUNITIES

The Massachusetts Clean Energy Center released a report on the workforce needs to support the clean energy goals of the Commonwealth.[53] The report concluded that the existing workforce cannot support the clean energy goals of the Commonwealth and through modeling has determined that over 38,000 additional workers will be required to support the transition; 3,794 jobs in the transmission and distribution sector. The Commonwealth's 2050 Decarbonization Roadmap Study estimates an increase of 18,000 jobs in the distribution and transmission sector by 2050.[54] The Commonwealth's Clean Energy Climate Plan to 2050 and 2030 identifies the addition of over 16,000 jobs in the distribution and transmission sectors by 2050.[55] There are many models with many different assumptions used to develop these estimates.

The Company supports the idea that more workers will be required and the skills of these workers may differ from existing skills. For instance, distribution equipment has become more computer based relying on communication networks that historically not been used in the field. Field staff will need to be trained in the installation, programming, testing and troubleshooting of communications equipment (radios, routers, modems, antenna, etc.) and controls.

The Company has a long history of hiring, training, and retaining the workforce necessary to provide safe and reliable service to our customers. The Company's focus on knowledge and experience has proven to be an effective approach to controlling costs. The Company's field workforce is typically covered by union labor agreements while the office and technical staff is a non-union workforce. The Company benefits from Unitil Service Company which is a shared workforce of technical and administrative services share between the Company and its affiliates. The Company began its transition to a more technical electric system when it first installed AMI on its system over 15 years ago and has employed union workers, including meter technicians, substation technicians, lineworkers, and stock room clerks, to install, monitor, and maintain the AMI infrastructure.

[53] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, dated July 2023. Powering the Future A Massachusetts Clean Energy Workforce Needs Assessment_Final.pdf (masscec.com)

[54] Economic and Health Impacts Report A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study December 2020 https://www.mass.gov/doc/economics-and-health-impacts-report/download Figure 7, Page 14

[55] Commonwealth's Clean Energy Climate Plan to 2050 https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050 , Figure 8-3, Page 139

In addition to the benefits above, the union collective bargaining agreements reflect opportunities for training and apprenticeship in positions. For example, agreements establish wages for Apprentice Lineworkers and Apprentice Substation Technicians, and prescribe a path of progression for training positions through multiple stages of classification (i.e., from Apprentice to First Class), each affording a higher wage. Progression is predicated upon completion of approved training programs.

The Company expects system improvement projects identified in the plan will be constructed and operated by union workforce. Establishing the communication systems that forms the backbone of the advanced electric system requires the installation, monitoring, and maintenance of equipment such as antennas, modems, power supplies, and repeaters. These are new technologies involving new work practices, and will require that current union employees to be trained in new skills (e.g., moving antennas and power supplies on poles) and that new union employees be hired to conduct work on an ongoing basis. The Company expects that the diversity of new skill requirements will result in the creation of a new positions and associated union classification. These union workers tend to reside in the local vicinity to the service territory. Because these union positions are local, the barrier of transportation is minimized for local applicants.

The design of the projects proposed under this plan is completed predominantly with internal engineering staff. The lead engineering staff is typically highly technical staff with college degrees and many years of experience. The engineers leading the project typical have engineers with less experience working closely with them. This on-the-job style training allows the lesser experienced engineers the ability to shadow a more experienced engineering in a mentorship role.

Operational and engineering staff attend industry conferences and seminars to understand the newest technology within the industry and how that technology can be deployed to benefit our customers. The Company also sends its employees to vendor specific training on new equipment to ensure safe and reliable installation and operation.

Engineering staff will need to extend their training and knowledge to the design and troubleshooting of communications equipment (radios, routers, modems, antenna, etc.) and controls. In addition, technical staff will need to be trained on the increasing complexity of relay schemes, FLISR, and systems integration to share data across systems.

The Company takes a holistic approach to talent recruitment. The Company believes that any applicant that demonstrates the aptitude to learn can be mentored on the specific requirements of the job. The Company is also engaged at the colleges and universities level serving as members of the industry advisory councils. These industry advisory councils work to ensure that student coming out of the universities and colleges have the tools and stills required to be successful. This work has proven successful in identifying potential employment candidates.

12.3 WORKFORCE TRAINING (WITH ACTION PLANS) – BARRIERS FOR BUILDING THE WORKFORCE NEEDED TO BUILD AND OPERATE THE GRID OF THE FUTURE

There are barriers to entering a new industry or new line of work and the energy industry is no different. The modern electric system requires an influx of new employees to be successful. Barriers such as awareness, diversity, equity, inclusion, language, proximity and transportation must be addressed in order to attract and train a new set of employees.

Awareness - Awareness may be the largest hurdle to identifying new employees. If an individual is not aware of the types of jobs within the energy industry, the probability of that individual seeking employment within the industry is low. Individuals who lack basic information about the energy industry early in their career may be less likely to search for a job in the energy industry.

The Company uses a broad range of multi-media to reach customer and prospective employees. Employee “word of mouth” referrals are generally highly effective at identifying prospective employees. A prospective employee is likely to take the recommendation of someone they know with first-hand knowledge of the Company. If the employee is happy with their position, receive a fair compensation and benefits, have the potential for training and advancement and likes their co-workers, their experience will resonate with individuals they know and trust.

The Company uses social media channels to reach our customers and prospective employees. Social media is proven to be an effective means to reach a larger audience. The Company proactively posts about job openings, career fairs, community events, interesting stories and other community events.

The Company works with local colleges and universities as members of their industry advisory boards to help provide guidance on curriculum and accreditation. This opportunity allows the Company to guide the colleges to develop courses that will provide the skills required to be successful in the energy industry. The Company supports those individuals who wish to expand their education through education reimbursement programs.

The Company works closely with the local colleges and universities to complete internship programs. Internship programs can be with any group in the company, but typically tend to be in the technical and sustainability parts of the Company. The internship consists of an overall introduction into the Company followed by projects of increasing difficulty all under the mentorship and training of more experienced staff. Interns are welcomed back to the Company for subsequent terms during their college career in the hopes that the intern will be hired upon graduation.

Diversity, Equity and Inclusion Barriers - The Company is an equal opportunity employer with a focus on diversity, equity and inclusion for individuals historically underrepresented in the industry, including women, people of color, and people who speak English as a second language. Our commitment to employee engagement is at the center of our core philosophies and is guided by our RISE values: Respect, Integrity, Stewardship, and Excellence. Through ongoing diversity, equity, and inclusion training and leveraging new recruiting channels, we are working to maintain and advance a culture that embraces diversity, promotes inclusion and attracts and retains employees from a broad spectrum of backgrounds and experiences. We believe we are a stronger organization when all voices and perspectives are equally represented. Recruiting from a diverse talent pool of qualified candidates to attract and retain top industry talent and maintaining an inclusive work environment ensures 'TeamUnitil' is a shared reality for everyone.

The strategy is to improve diversity through expanded recruitment and partnerships while fostering retention and employee growth by building Diversity, Equity and Inclusion ("DEI") awareness and competency, improving culture and relationships, and demonstrating commitment. To support ongoing efforts to create a healthy, productive environment for our employees, we formed a Diversity, Equity and Inclusion Council (DEI Council), a 15-member group tasked with ensuring these important concepts are woven deeply into the fabric of our culture. The DEI Council established a charter, furthered employee education events, contributed to our DEI strategy, and created an employee newsletter to celebrate and share our progress and commitment to DEI. To create a value feedback loop, the DEI Council established the first Employee Resource Group to focus specifically on the empowerment of women in the utilities industry. We demonstrate our commitment to DEI through the expansion of recruitment channels to specifically target veterans, women, and members of the LGBTQ+ community, among others. The vigilant monitoring of equitable hiring practices will ensure we remain competitive within our industry and market.

Our DEI Council has engaged New England-based Mars Hill Group to assist in educating our employees about diversity. The Mars Hill Group conducts multiple learning sessions for all employees focused on diversity awareness in the workplace. The Mars Hill group also works hand-in-hand with the DEI Council to create a charter and action plan to define goals and facilitate our diversity initiatives. The Mars Hill Group conducts well-attended unconscious bias in-person training sessions for all employees.

As described in the comments of the Undersecretary of Environment Justice and Equity, "As the clean energy economy grows, electric distribution companies should ensure their workforce is inclusive of Black, Brown, Immigrant, Indigenous and low-income residents. As we grow the workforce needed to electrify the grid, EJ populations must have access to good paying and stable jobs. This includes creating a permanent pathway for residents who currently work in fossil fuel industries so they can transition to new clean energy jobs, as well as a pathway for the younger generations and those who have historically not had access to energy sector jobs."[56] These comments fit nicely with our approach to diversity, equity and inclusion within our company and within the community.

<u>Language Barrier</u> - The Company's service territory is predominantly English speaking, however Spanish and Portuguese are commonly spoken as well. Since the Company's service territory is relatively small and many of our employees live within the service territory, the Company currently has employees who speak Spanish and Portuguese. Therefore, the Company does not believe that language would be a barrier to new employees but offers training and assistance where required to ensure success within the Company.

<u>Proximity and Transportation Barriers</u> – Prospective employees who may be from disadvantaged backgrounds or communities may have a barrier to employment due to their proximity to the work location or their ability to get transportation to and from the office. Many people tend to look for employment within their immediate vicinity due to the inability to relocate to find employment. Since the Company's service territory is relatively small and many of our employees live within the service territory, transportation also does not tend to be an issue due to the relatively small footprint of the territory.

[56] August 14, 2023 comments from the Undersecretary of Environment Justice and Equity to the Grid Modernization Advisory Council.

Training Barriers – The Company is constantly working to increase the quantity and access to training for our employees and prospective employees. The Company encourages individuals of all backgrounds to apply. Those employees who are a good fit but may not have the necessary education, training or experience are provided with the opportunity to increase their education through tuition reimbursement, their skills through paid training and their experience through on-the-job training opportunities under the close guidance of a mentor. The Company looks for opportunities to work with schools, vocational centers, apprentice programs, and other programs with a particular focus on providing a just transition of the workforce providing opportunities for historically underrepresented communities who may not have otherwise had the opportunity.

The Company recognizes that there is an opportunity to provide training opportunities to workers seeking to transition their experience to the clean energy sector. The Company has both gas and electric workers and will identify and implement training opportunities where appropriate to allow employees to transition their skills from the gas to the electric side of the business.

12.4 LOCATION ECONOMIC DEVELOPMENT IMPACTS

In order for economic activity to benefit a certain location, the money needs to remain local. Income growth and job creation are key aspects to driving improvements to the local economy.

Job creation benefits the communities within our service territory. The types of jobs created by the modern grid are good paying labor, vocational and technical positions which will drive income growth for the communities. The Company expects these jobs will be filled by applicants within our service territory. Individuals who have the opportunity to earn more money will tend to spend that money within the communities they live in, such as going out to dinner, shopping and purchasing the goods and services they need. As each dollar is spent and re-spent within the communities it will drive an overall improvement to the local economy.

Investment in the electric system increases the value of the taxable assets within a certain town. These assets are taxed by the town. Increased tax revenues within the town are reinvested within the town in job creation, town improvements and reducing the tax burden on residents.

The location of an investment may also cause harm on the local community. At times this harm can be disproportionate depending on the cumulative burden already carried by certain neighborhoods or communities. Possible substation locations are evaluated for any burdens that may be placed on the surrounding neighborhoods and consideration given to reduce the impacts to historically disadvantaged neighborhoods.

In an effort to quantify the economic benefits of the investment, the Company uses the Regional Input-Output Modeling System ("RIMS II")[57] model developed by the Bureau of Economic Analysis ("BEA"). The BEA is a federal agency that promotes a better understanding of the economy by providing timely, relevant, and accurate economic data.[58] The RIMS II model is designed to identify the potential economic impacts of various products. The RIMS II model relies on multipliers to study the economic impact for a wide range of projects.

For the purpose of this analysis, the RIMS II methodology uses the Company's base capital spending, in-progress capital programs and ESMP proposed investments. The RIMS II multiplier for "electric power generation, transmission and distribution" projects is 1.244. This means that an investment of $ 1 million would result in benefits of $1.244 million dollars. Therefore, the investment of $131 million of capital spending described in this ESMP from 2025-2029 results in total benefits of approximately $163 million and incremental benefits of approximately $32 million.

In addition, the RIMS II model can also be used to estimate the number of jobs created. The estimate uses a multiplier of 1.920 for the number of job created in all industries for an investment in the "Electric power generation, transmission and distribution" category. Therefore, the investment of $131 million of capital spending described in this ESMP from 2025-2029 results in the creation of 250 jobs.

The RIMS II Type I multipliers estimate job creation by employing economic multipliers that take into account the direct and indirect employment impacts of economic activity. For direct jobs, the model forecasts the positions directly created as a result of a specific project or investment, like those at a newly built substation. For indirect jobs, the model takes into account the positions created in related industries due to the initial investment, such as third-party entities

[57] https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf

[58] https://www.commerce.gov/bureaus-and-offices/bea#:~:text=BEA%20is%20an%20independent%2C%20principal,objective%20and%20cost%2Deffective%20manner.

supplying materials or services to the construction of the substation.[59] The direct and indirect impacts of these calculations reflect a broad perspective of the impact of the direct economic activity and the associated rounds of spending in the economy associated with these investments. It is important to note that the job creation figures calculated here include both full-time and part-time positions and are not equivalent to FTE positions.

According to the RIMS II model, the number of jobs created represents the total change in the job counts across all industries for every additional $1 million of output delivered to final demand. These job creation figures are calculated by multiplying the annual investment by the respective industry's employment ratio at the state level, in this case the Electric Power Generation, Transmission, and Distribution category.

12.5 HEALTH BENEFITS

The primary health benefits associated with this plan are focused around enabling the interconnection of renewable energy resources and optimizing system demand at all times of the year. These efforts will reduce GHG emissions created by burning fossil fuels. Electrification and the interconnection of clean energy resources will reduce exposure to harmful pollution. A reduction in GHG emissions will have a direct impact on improving air quality, result in less respiratory illness and prevent other health related conditions due to increased temperatures.

The electric system as an enabling platform strives to minimize GHG emissions by integrating greater renewable energy DER and empowering customer energy options. Technology advancements in monitoring and control of DERs will allow the interconnection and operation of a larger percentage of renewable energy resources than otherwise could have been supported. Demand reduction programs supported by advanced monitoring and control will lead to the replacement of inefficient end use devices.

VVO provides the opportunity for improved energy efficiency leading to decreases in demand and reduction in greenhouse gas emissions. In addition, the VVO system also enables the Company to manage customer power quality better and allows for a greater penetration of renewable DERs on the system and lead to a further reduction in GHG emissions.

[59] A third category of impact is called "Induced" Impact. This impact is not modeled in the RIMS II Type I multipliers. Induced Impact is the change in economic activity resulting from the changes in spending by workers whose earnings are affected by a final-demand change. For example, spending at a restaurant by a construction worker employed to build a substation could be captured by an Induced Impact.

AMI provides the data and tools necessary to drive a reduction of electricity usages and peak load reduction. The information provided by AMI gives customers the opportunity to take more control over their energy usage leading to reduced emissions. AMI supports reduced overall energy usage through VVO and energy management systems. AMI helps to reduce peak demand by supporting dynamic pricing (such as TOU or TVR), energy management and smart appliances. AMI reduces emissions by eliminating the transportation required for meter reading fleets.

Integrating DERs and other renewable resources into the distribution system is key to an environmentally friendly distribution system. AMI provides the information necessary to match actual load usage curves with the potential DERs supporting the load. In addition, AMI supports demand side management programs which reduces distribution and transmission peaks resulting in lower peak loads, reduces emissions and reduces the need for non-environmentally friendly generation resources.

Technology improvements in roof top solar continues to drive the price point lower and lower. The costs of other DERs such as energy storage and energy efficiency improvements are also experiencing decreasing pricing and increased sales. Demand response opportunities continue to grow as home assets such as HVAC, water heaters, LED lights, thermostats and even electric vehicles as the ability to control these assets from the internet become more prevalent.

A sustainable and environmentally friendly electric distribution system requires effective and efficient use of electricity. Customers who have knowledge, tools and technology can support the overall goals of energy conservation during peak load hours leading to reduced emissions. Customers who are engaged and have a clear understanding of their individual situations have a greater tendency to make beneficial changes.

13 CONCLUSION

The Plan is designed to detail the Company's actions to proactively upgrade its distribution (and transmission system where applicable) to: (i) improve reliability and resiliency; (ii) increase the timely adoption of renewable energy resources; (iii) promote energy storage and electrification technologies; (iv) prepare for future climate-driven impacts on the electric system; (v) accommodate increased electrification from transportation, building and other potential demands; (vi) minimize or mitigate the impact to ratepayers while helping the commonwealth realize its greenhouse gas emission limits.

The Company has taken a measured approach to this Plan. Due to the Company's overall size, it cannot be all things to all people. We need to focus on the needs of our customers. This report is a living document designed to provide direction and guidance to address the goals listed above but maintain flexibility to alter the plan to address future challenges that have not yet been identified. The plan provides a 5-year forecast, 10-year forecast and a demand assessment through 2050 to account for future needs. This plan will continue to be updated and improved upon based upon feedback from stakeholders as well as changing future conditions. The Company looks forward to continued collaboration on the development and implementation of this Plan.

13.1 NEXT STEPS

The Climate Act requires the Company to file its Plan with the GMAC by September 1, 2023. The Company is committed to two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. The Company will use the feedback from the GMAC to improve on its Plan prior to submitting the report to the Department in January 2024.

The Company supports the concept proposed by the EDCs to develop a Community Engagement Stakeholder Advisory Group. The goal of the new advisory group is to develop a Community Engagement Framework that can be applied to infrastructure projects before they are brought before the EFSB. The composition of the advisory group will be informed by the GMAC, utilities and any comments to the initial filing of the ESMP with GMAC.

The EDCs will propose metrics and a reporting template for stakeholder review and comment prior to submitting the ESMP to the Department in January. These metrics and reporting template will be designed to support transparency and accommodate mid-term modifications based on GMAC and stakeholder feedback prior to submission of the Company's next ESMP in 2028.

The Company will continue to make improvements to portions of the Plan including but not limited to customer benefit analysis and quantification of GHG emission reductions resulting from the investments where applicable.

13.2 PROCESS TO SUPPORT UPDATES TO ESMP THROUGHOUT THE 5-YEAR CYCLE

The Climate Law, Section 92B (e) requires the EDCs to submit two reports per year to the Department and the Joint Committee on Telecommunications, Utilities, and Energy on the deployment of approved investments in accordance with any performance metrics included in the approved plans.

To ensure all ESMP reports are valuable, actionable and support transparency with the GMAC, stakeholders, regulators and policy makers, the EDCs support development of a common reporting template. At a minimum, the template would include provisions for the EDCs to report on progress in implementation, stakeholder engagement, and benefit realization. As described in Section 13.3, the EDCs also support adoption of common performance metrics. Results relative to these metrics would be included in ESMP reports.

The EDCs recommend bi-annual reporting as follows:

- April 1, for the prior year plan period providing a comprehensive report on ESMP progress, including results relative to performance metrics. (Replacing the current Grid Modernization Plan Annual Report.)
- October 1, for the six months of the current year, January through June, to provide a higher-level interim review of year-to-date progress.

This process would involve a review of the prior two bi-annual reports and an assessment and recommendation from the Company or joint EDC's regarding elements of the ESMP or specific investments. The EDCs expectation is that this review cycle will help to refine and improve the ESMP and the ability to move forward in supporting the state's clean energy future in a cost effective and efficient manner.

13.3 REPORTING AND METRICS REQUIREMENTS WITH COMMON EDC TABLE

The EDCs support the creation of metrics to measure progress and performance of the ESMP investments in relation to the ESMP objectives. The EDCs are performance-focused and aspire to provide safe, reliable, and cost-effective service to all customers every single day. Consistent reporting and metric measures for the ESMP will provide transparency into the performance on the approved ESMPs and provide opportunities to adjust for improvements as the plans are implemented.

The EDCs note that they have already committed to metrics in other areas and there are many filed and publicly available metrics across several open or active dockets at the Department. There are several existing frameworks and reporting constructs that should initially be considered and leveraged for any suitable and transferable metrics.

The EDCs have reviewed the metrics that are currently approved or are in process of consideration by the Department and have classified those investment categories that we consider to be applicable to the ESMP and those that are not applicable to the ESMP.

The following investment categories have existing or pending metrics that are directly applicable to the ESMP objectives. Metrics existing or proposed in these areas could be incorporated into the ESMP reporting template with necessary revisions.

- Grid Modernization
- Electric Vehicles
- AMI / Time Varying Rates
- Interconnection Timelines

The following investment categories have existing or pending metrics that are not applicable to the ESMP given that they are either, specific to an EDC, have a separate existing stakeholder process in place, or are not directly applicable to the ESMP objectives.

- Energy Efficiency
- CIP
- Service Quality
- Rate Case

The EDCs view the existing set of metrics as an optimum starting point to develop the overall comprehensive set of metrics to measure ESMP investments and outcomes in relation to the ESMP objectives. This starting point can be supplemented with additional metrics that track the ESMPs implementation once approved by the Department.

In addition to including existing metrics into the ESMP reporting template as described above, the EDCs are working to develop new, ESMP-specific, metrics designed to ensure full transparency with respect to all ESMP expected outcomes. The EDCs are planning the following process to develop a full metric recommendation for inclusion in each Company's ESMP filing to the Department in January.

- EDCs propose ESMP metrics (new and existing/proposed) by October 1, 2023

- Conduct collaborative stakeholder sessions to gather feedback on EDC proposed metrics
- Final recommendation of ESMP metrics, incorporating stakeholder feedback, is presented to the Department in January.

The EDCs propose to deliver both infrastructure and performance metrics, which will include both statewide as well as company-specific metrics, tied to each Company's ESMP goals. Infrastructure metrics track the implementation of approved technologies and systems, and performance metrics measure progress towards the ESMP outcomes.

In developing metrics associated with each goal and outcome as this proceeding moves forward, it is imperative that such metrics follow the following principles:

1. be susceptible to objective and transparent measurement;
2. have an established baseline against which performance can be measured;
3. measure "performance" that is actually within the EDC's control; and
4. must also consider whether there are conditions precedent for any metrics that need to be factored into their use or measurement. Metrics that lack these foundational elements could result in unintended consequences of penalizing a utility for performance that is not actually substandard, nor a product of the utility's own efforts.

Additional areas of consideration for creating metrics include:

- Legislative compliance – meet the expectations laid out in the Climate Act;
- State Goals and Policy Delivery – focus on achievement of State policy goals;
- Customer Value – creates/demonstrates value for customers, balancing the burden across our customer demographics;
- Inter-Metric Consistency – consider performance metrics holistically, avoiding a metrics paradox, where achievement of one metric necessarily means giving up or failing on others.

The EDCs have developed an initial view of both the statewide and company-specific metrics. The purpose of these ESMP metrics is to record and report information, internally, to the Department, to GMAC, and to the TUE. Infrastructure metrics track a Company's deployment and investments of ESMP projects and technologies. Examples of existing infrastructure metrics include, number of AMI meters installed, number of feeder monitors installed, and milestones for approved technologies and projects.

The EDCs will propose additional performance metrics to track the benefits resulting from the Company's ESMP implementation. Examples of performance metrics include those that measure achievement of specific proposed outcomes, such as energy and demand savings resulting from CVR/VVO.

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Council and other stakeholders throughout the ESMP plan period with discussion and updates supported through the bi-annual reporting. The table below summarizes the categories of metrics the EDCs are working to develop.

Category	Description
Implementation	Delivery of ESMP investments relative to established milestones
Resiliency	Customers benefitting from resiliency investment and improvements in relevant outage statistics
Electrification and DER Hosting Capacity	Amount of Electrification and DER capacity enabled on the distribution system
Use of DER as a Grid Asset	Amount of capacity enabling Grid Services and Flexible Load
Stakeholder Outreach	Specific engagements with stakeholders including those in EJ, disadvantaged or underserved communities

Table 47 – Potential Metric Categories

As noted above, the metrics categories above are expected to have specific metrics that are a combination of the existing metrics discussed above and new metrics created through a stakeholder engagement process related to developing the appropriate metrics for the ESMPs.

13.4 PROCESS TO REPORT TO DPU AND JOINT COMMITTEE ON TELECOM, UTILITIES AND ENERGY

The EDC's expect an ongoing collaboration with the Grid Modernization Advisory Committee throughout the ESMP plan period with discussion and updates supported through the bi-annual reporting. In addition to the GMAC, the bi-annual reports will be provided to the Joint Committee on Telecommunications, Utilities, and Energy. As described in 13.2, the EDC's believe the proper timeframe for the bi-annual reporting would be April 1 for the July – Dec timeframe and October 1 for the Jan-Jun timeframe. These timelines best align with many existing dockets and annual reporting timelines which will be leveraged and incorporated into our overall bi-annual reporting efforts.