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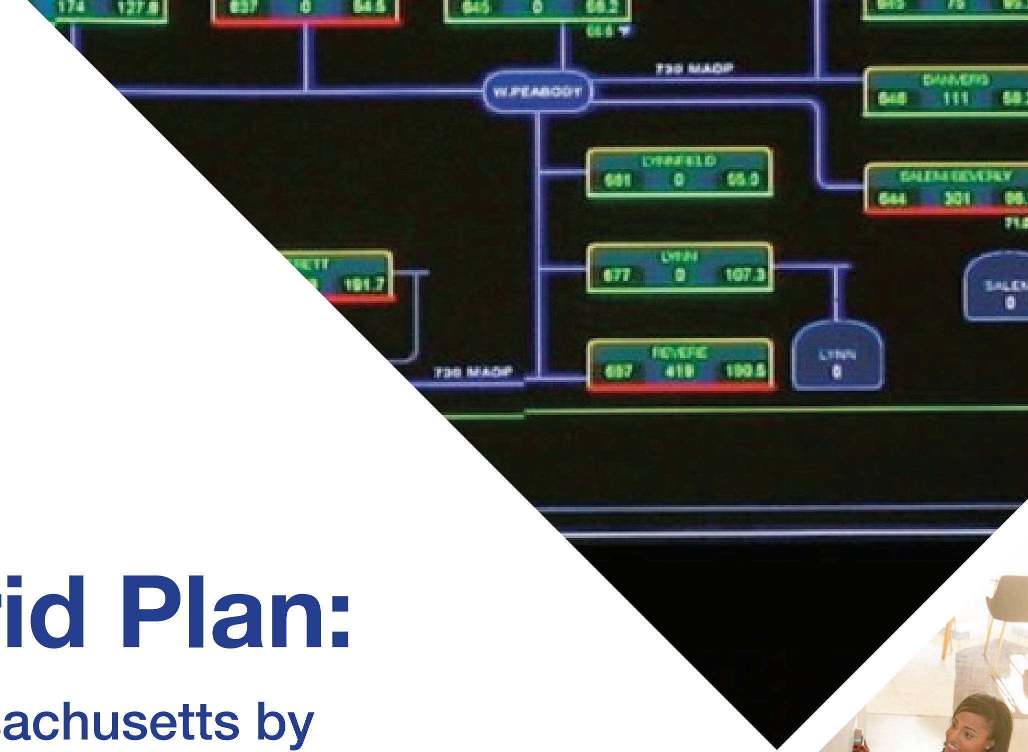


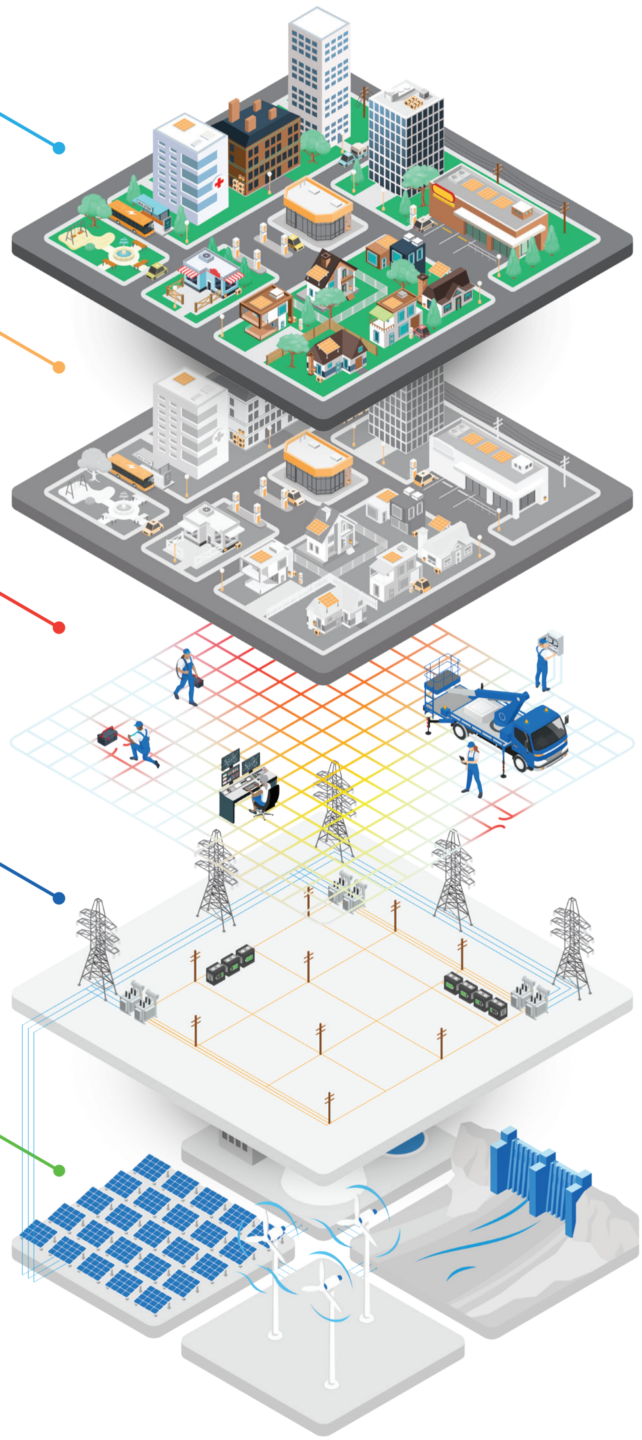
Future Grid Plan:

Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future

January 2024

nationalgrid

Building Tomorrow's Energy System



A Smarter, Stronger, Cleaner, More Equitable Energy Future

A network that supports the Commonwealth's climate, clean energy, and equity goals and delivers the fair, affordable, and clean energy transition for all our customers and communities.

Customer Programs

Provide customers with information, products, and services to enable clean energy, efficiency, and demand management options so they can make the energy choices that work for them, when they want them.

Communications and Technology Platforms

Create a smart, flexible, and dynamic grid that can manage the future supply mix and energy needs, and leverages distributed resources with real-time communications to solve grid problems and provide grid resiliency.

Network Infrastructure

Build a strong network that is one step ahead of customer needs, ready to respond to developer requests, and is reliable, resilient, and secure, regardless of weather or evolving threats.

Connecting our Customers to Renewables

Enable and connect our customers to the increased renewable generation on the grid – wind, solar, hydro, geothermal, and storage.

The investments proposed in this Future Grid Plan will empower our customers and communities throughout Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future....

.... and enable customer adoption of clean, electrified technologies to drive down greenhouse gas emissions while improving their energy experience.

Improving comfort and convenience 1

Before Tina comes home, her house is cooled to a pre-set temperature so it's comfortable for her when she arrives.

Optimizing battery and solar to provide resources and value 2 3 4

Tina settles in and does a load of laundry 2. Given peak demand conditions, with other neighbors also coming home, her battery 3 in the garage cycles on and off based on solar panels 4 from her roof and grid conditions (charging and discharging where optimal) to offset those costs.

Saving money and reducing peak demand 2 5

Tina just finished dinner and loaded the dishwasher 5. Tina's dishwasher and dryer 2 start automatically when electric prices are lowest to optimize her bill and her demand on the grid.

Filling the "tank" at the lowest cost and carbon footprint 3

While Tina is sleeping, car charging 3 is actively managed based on grid conditions, and will be fully charged when she needs it in the morning for work.

Leveraging innovation to save energy and money 6

Tina's home and the grid talk to each other constantly. With her permission, extra energy can be sent back to the grid, allowing her to potentially earn money from her solar panels. Alternatively, when Tina needs extra power, her devices are managed so well that they will allow her to avoid a costly service transformer upgrade.

Table of contents

A message from our leadership

Lisa Wieland
President
New England

Nicola Medalova
Chief Operating
Officer, New England

Every day at National Grid, our more than 6,500 team members work together to build a smarter, stronger, cleaner, and more equitable energy future for our customers and communities in more than 240 towns and cities across 5,900 square miles.

We know what we do matters immensely, and how we do it matters even more.

We are at an inflection point. To meet the Commonwealth's ambitious climate change and clean energy goals – goals that we share – we must begin building this future now. And, we know that we cannot build it alone and that we don't have all the answers. Massachusetts is a state known for solving big problems and delivering big results. It is a state with an innovation ecosystem and is focused on equity that drives collaboration, partnership, and new ways of thinking. We will need to harness this innovative and collaborative spirit to achieve the energy future that works for all.

By developing and filing this Future Grid Plan proposal as our Electric Sector Modernization Plan, we are taking a first step toward defining the scope and scale of what we collectively must do over the next 25 years to combat climate change and enable a more electrified future. We are doing this by identifying the system investments and changes needed in the electric distribution system, engaging broadly to stimulate ideas, and encouraging input to ensure this proposal is responsive to and supportive of the needs and expectations of all our customers and communities. In the developing of this Plan, we have listened earnestly to stakeholders, and incorporated the vast majority of this feedback to ensure we are delivering for everyone.

The investments proposed in this Plan will enable a smarter and more intelligent system that provides customers with more options and the ability to make clean energy decisions that work for them. They will result in a stronger system that is more robust, better able to withstand the impacts of climate change, and protects against evolving threats. And, they will support the quicker connection of more renewable resources, energy storage, and electrified transportation and heating at all levels to create a cleaner system that leverages these resources to create value for the grid and customers.

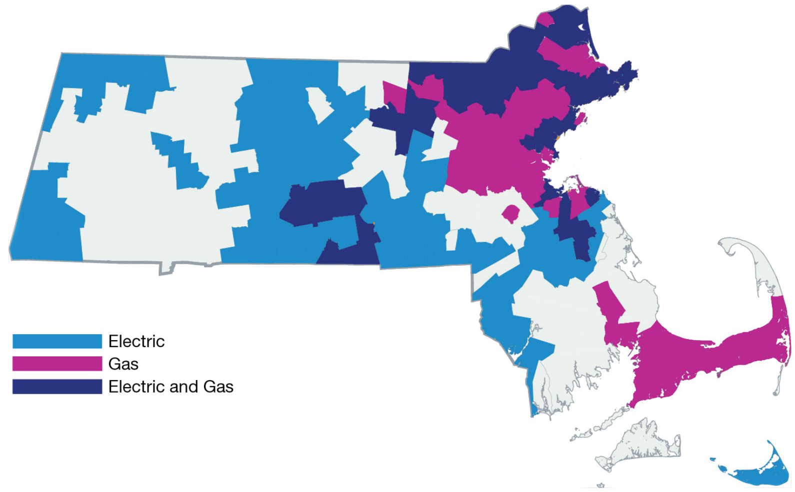
We have an opportunity to make real and lasting change. And, while we are building and preparing the grid and our broader energy system for the future, we remain focused on what is right in front of us. Our customers expect and deserve great service and safe, reliable and affordable energy today, which we will continue to deliver. We are committed to empowering Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future. And we are excited to share our Plan to do that and truly look forward to being a partner for progress in all our communities across the Commonwealth.

Lisa Wieland
NE President

Nicola Medalova
Chief Operating Officer, NE Electric

About us

We're taking action to achieve net zero greenhouse gas emissions and deliver a fair, affordable and clean energy future to **2.3 million customers** in more than **240 towns and cities.**



Serving our 1.3M electric customers via our networks...

18.5K Miles of electric distribution lines

264 Distribution substations

720K Poles

...by our teams...

~6,500 Employees

~3,300 Employees represented by 15 unions

...while supporting our communities...

13K+ hours of employee volunteerism

$4M+ in charitable contributions

...and making customer connections.

200 MW Total DER connected in 2022	**~1,800** EV chargers enabled to date	**18K+** Households that installed heat pumps in 2022 through the Mass Save program, with 10k+ supported by National Grid
2.3GW DER connected to our network	**~32K** Additional EV chargers to be enabled via Phase 3 EV programs	**45K+** Planned additional households for heat pump installation through Mass Save by 2024, with 21k+ targeted for support by National Grid

1.0 Executive Summary

National Grid is committed to enabling the fair, affordable, clean energy transition for the 2.3 million customers in more than 240 towns and cities it is privileged to serve across the Commonwealth for both electricity and gas. Meeting the Commonwealth's nation-leading decarbonization goals established in the 2050 Clean Energy and Climate Plan (2050 CECP) will require significant amounts of new renewable and clean energy resources to be connected to the electric grid, and customers across the Commonwealth to accelerate the adoption of clean, electrified technologies.

By 2050, the Commonwealth's electric distribution system will be the primary energy network powering the economy and all aspects of everyday life – including cooking, heating, and transportation. Enabling this new energy future requires investment at pace and scale to make the grid fundamentally smarter, stronger, and cleaner than it is today.

National Grid crafted this Future Grid Plan (Plan), which serves as the Company's Electric Sector Modernization Plan (ESMP) submission, to meet the Commonwealth's 2050 decarbonization and equity goals and interim milestones. The Plan was informed by recommendations from the Grid Modernization Advisory Council (GMAC) and feedback gained through robust and meaningful dialog with a broad and diverse range of its customers and stakeholders from across the Commonwealth, including from its environmental justice communities (EJCs). This feedback guided the Company's planning considerations and decision making on proposed investments.

This Plan provides a roadmap of the electric distribution system investments (i.e., network infrastructure, communications and technology platforms, and customer programs), policy recommendations, innovations like non-wires alternatives (NWAs), rate design principles, and expanded stakeholder outreach and engagement necessary to successfully deliver the 2050 CECP goals and a just transition. Successful delivery will also require parallel efforts on transmission infrastructure investments, regulatory and policy changes, large-scale clean electricity generation, customer demand-side programs, including energy efficiency, and increasing levels of coordinated, integrated energy planning between gas and electric systems to achieve this transition reliably, safely, and affordably.

At its core, a transformation of the entire energy ecosystem is required to equitably achieve the net zero ambitions of the Commonwealth. The electric distribution network is foundational to enabling this transformation. It will require new and expanded infrastructure in all communities to meet growing demand and collaboration and engagement among all of society.

Recognizing that as the Commonwealth makes the energy transition it must keep affordability and equity at the fore, the Future Grid Plan is deliberately designed to make progress towards the 2030, 2035 and 2050 decarbonization goals. To do this the Company uses transparent, data-driven, proactive distribution system planning to identify and ensure the most cost-effective solutions are implemented and an assessment of the tradeoffs between the pace of proactive investments and overall affordability to customers. The Plan leverages distributed energy resources (DER) to address reliability needs and defer system upgrades through NWAs, provides economic benefit and opportunity, with a focus on traditionally underrepresented communities, and empowers customers to make the energy choices that work for them and their budget, when they want to make them.

The 5-year Future Grid Plan will enable 31.3 MMT of greenhouse gas (GHG) emissions reductions, by increasing distribution network capacity by 1 GW. Compared to today, this will enable up to 50% more solar and storage on our system, 15 times more EVs on the road and 8 times more heat pumps installed. Importantly, this is incremental to what the rest of our system is already built to deliver.
This holistic Plan builds on investments underway and proposed that will collectively enable a smarter,

stronger, cleaner, and more equitable energy future and achieve the Commonwealth's net zero climate goals. This includes supporting our share the Commonwealth's 2035 goals of 1.1 million EVs on the road and 330,000 heat pumps installed. The below table outlines the incremental outcomes delivered by the Future Grid Plan only, not our existing collective investments of base spending.

Summary of what the Future Grid Plan delivers for our customers, communities and the Commonwealth, incremental to pending investments*

	Today	Our 5-year plan (2025 – 2029) delivers…	Our 10-year plan (2030 – 2034) delivers…
Our Network	264 substations 1,318 distribution feeders	13 upgraded substations Expansion of 14 feeders	32 new/upgraded substations Expansion of 13 feeders
Solar and Energy Storage	2.3 GW connected	Supports an incremental 1 GW, including capital investment projects (CIPs)	Supports an incremental 3GW
EVs	32,000 on the road	Enables up to 492k additional EVs	Enables up to 870k additional EVs
Heat Pumps	10,000 installed	Enables up to 84k additional electric heat pumps (EHPs)	Enables up to 235k additional electric heat pumps (EHPs)
NWAs & Enabling Tech	One battery project on Nantucket to avoid an undersea cable	Advances 17 Bridge-to-Wires NWAs & 2 deferral NWAs including equity-focused VPP offerings	Expanded NWAs to defer investments, at scale
Economic Activity & Jobs Created		More than 3,900 full- and part-time jobs, and $500 million of incremental economic activity, for the proposed ESMP investments	More than 8,700 full- and part-time jobs and $1.1 billion of incremental economic output, for the proposed ESMP investments

*Outcomes presented in the above table are associated with Future Grid investments only. Once combined with our pending base investments, in 2034, economic activity and jobs created are $3.6B and 28,000, respectively.

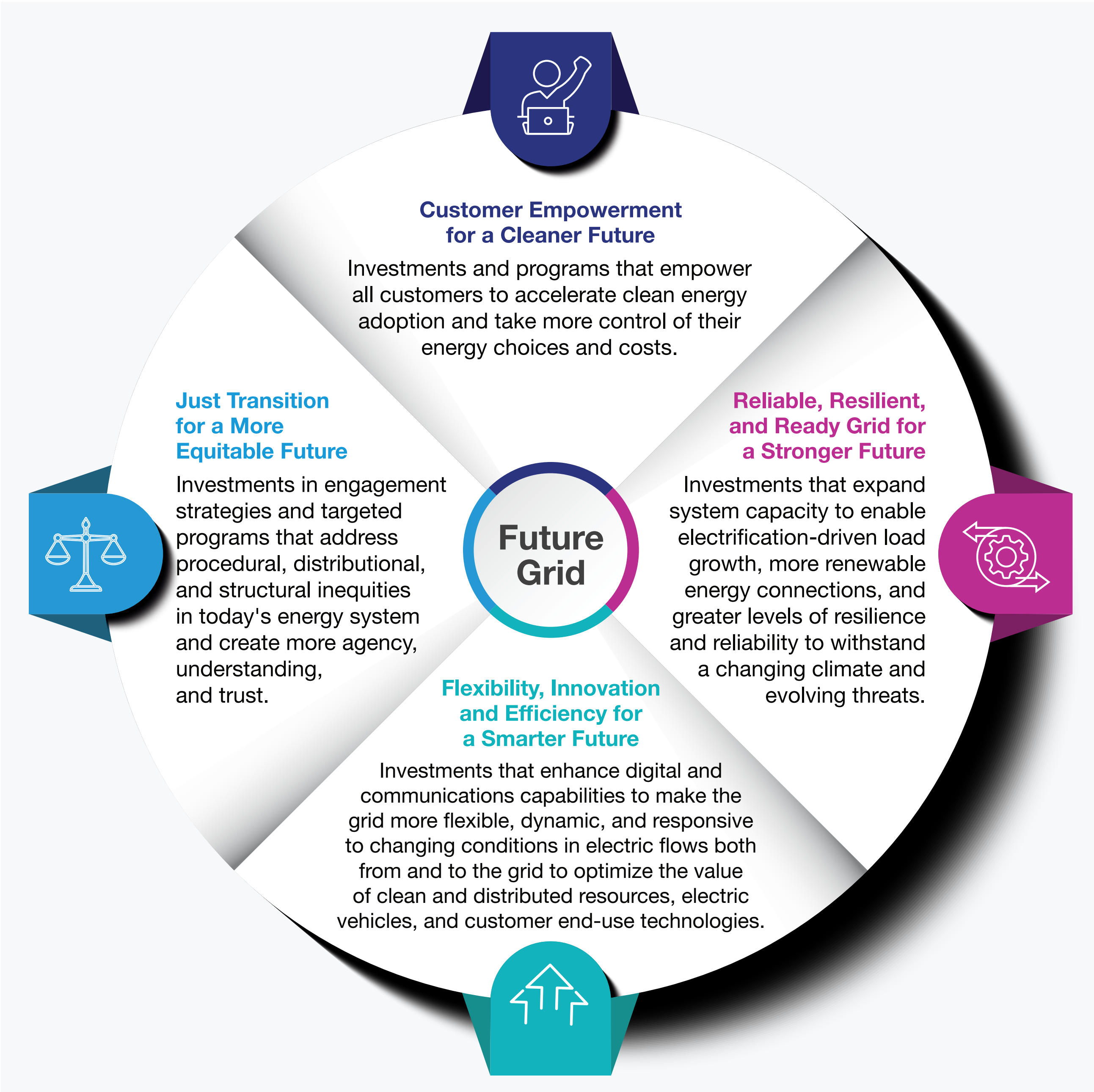
1.1 Vision: Enabling a Just Transition to a Reliable and Resilient Clean Energy Future

National Grid is committed to enabling the fair, affordable, and clean energy future and a just transition. This requires re-imagining the future of the electric network, its relationship to customers and communities, its capabilities and opportunities, and the corresponding regulatory paradigms necessary to ensure we are:

- Empowering customers to make clean energy choices;
- Creating a ready, reliable, and more resilient grid capable of withstanding extreme weather and evolving threats;
- Leveraging innovation, driving efficiency, and enabling greater system flexibility; and
- Enabling a more just and equitable energy future that provides benefits for all.

National Grid's approach to the clean energy transition starts with the customer—understanding their evolving energy needs, giving them more information and more choices, and supporting their side of the clean energy effort through programs, rates and other offerings. It then establishes the investment pathway necessary to deliver these outcomes, using specific criteria to assess and develop the required investments in network infrastructure, technology and communications platforms, and customer programs, with the goal of enabling a just and equitable energy transition.

National Grid's Customer-Driven Future Grid Plan



1.2 Plan Overview and Alignment with the Clean Energy and Climate Plan

Massachusetts' 2050 CECP establishes nation-leading goals and supporting pathways to reduce climate pollution and reach net zero greenhouse gas emissions by 2050 – goals we share at National Grid. The 2050 CECP is an equity-centered plan rooted in decarbonizing the electricity consumed by all customers and using this clean electricity to power all aspects of the economy. The CECP's electrification-based approach to achieving net zero emissions requires the Commonwealth's electric networks to become the foundation of the economy and our region's primary energy system.

An Act Driving Clean Energy and Offshore Wind (2022 Climate Act or Act), directed each Massachusetts electric distribution company (EDC) to file an ESMP that identifies "upgrades... needed to meet the Commonwealth's climate and clean energy goals over three planning horizons: 1) a 5-year forecast, 2) a 10-year forecast and 3) a demand assessment through 2050." The Company conducted these forecasts and assessments and identified the investments necessary to transform our electric distribution network at the pace and scale necessary to meet the Commonwealth's long-term and interim climate and clean energy goals,

The 2050 CECP forecasts suggest that solar, storage, EVs, and heat pump adoption is expected to soar statewide by 2035 and the grid must be ready*

2050 CECP pathways to accomplishing the Commonwealth's net zero greenhouse gas emissions goals[1]

Transportation

97% of light-duty vehicles (5 million) electrified

93% of medium- and heavy-duty vehicles (over 350,000) electrified or non-emitting

Buildings

80% of homes (over 2.8 million) heated and cooled by electric heat pumps (including those with on-site fuel backups)

87% of commercial space heated by either electricity or alternative fuels

Electric Power

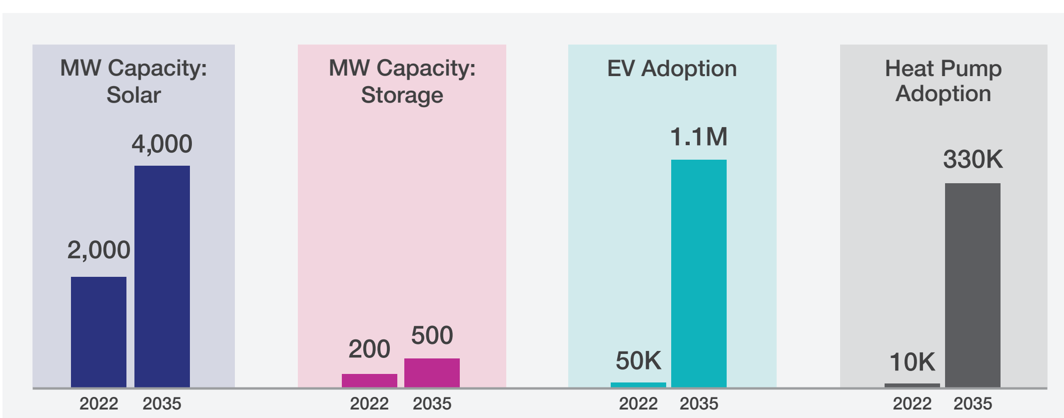
2.5-fold increase in electric load compared to 2020

97% of electricity consumed is from clean and renewable sources

Non-Energy and Industrial

52% of industrial energy use electrified

*These are approximate values



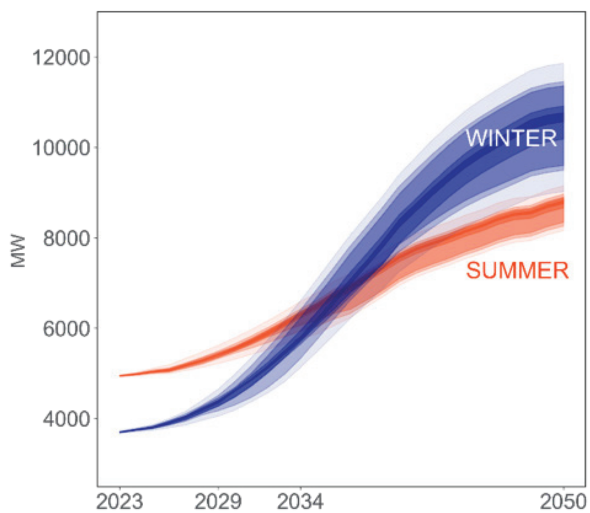
[1] These are statewide goals from the Clean Energy and Climate Plan (CECP).

The Company's Future Grid Plan enables the Commonwealth to achieve its goals

National Grid is responsible for the safety and reliability of the electric distribution system, including the planning and building of infrastructure and implementation of technologies needed to meet future electrification and growth in DER. The Company's assessment of both the needs and solutions of the electric distribution grid over the next five and ten years is informed by its view of what it will take to achieve the objectives described in the 2050 CECP, meet the established interim milestones, and continue to provide safe and reliable service to our customers.

The electric distribution grid must be expanded to connect at least twice the amount of energy storage and 10 times the amount of renewable energy than today to decarbonize the electricity being used to meet this demand in 2050. Concurrently, driven by heating and transportation electrification, as presented in Section 8: 2035 – 2050 Policy Drivers: Electric Demand Assessment, electric demand growth will continue to rise beyond 2035 and is projected to more than double from a peak of 4.9 GW today to 10.7 GW by 2050. This peak will occur in the winter as opposed to summer, which has implications for system operations, performance, and availability of energy resources, such as solar, to meet growing need.

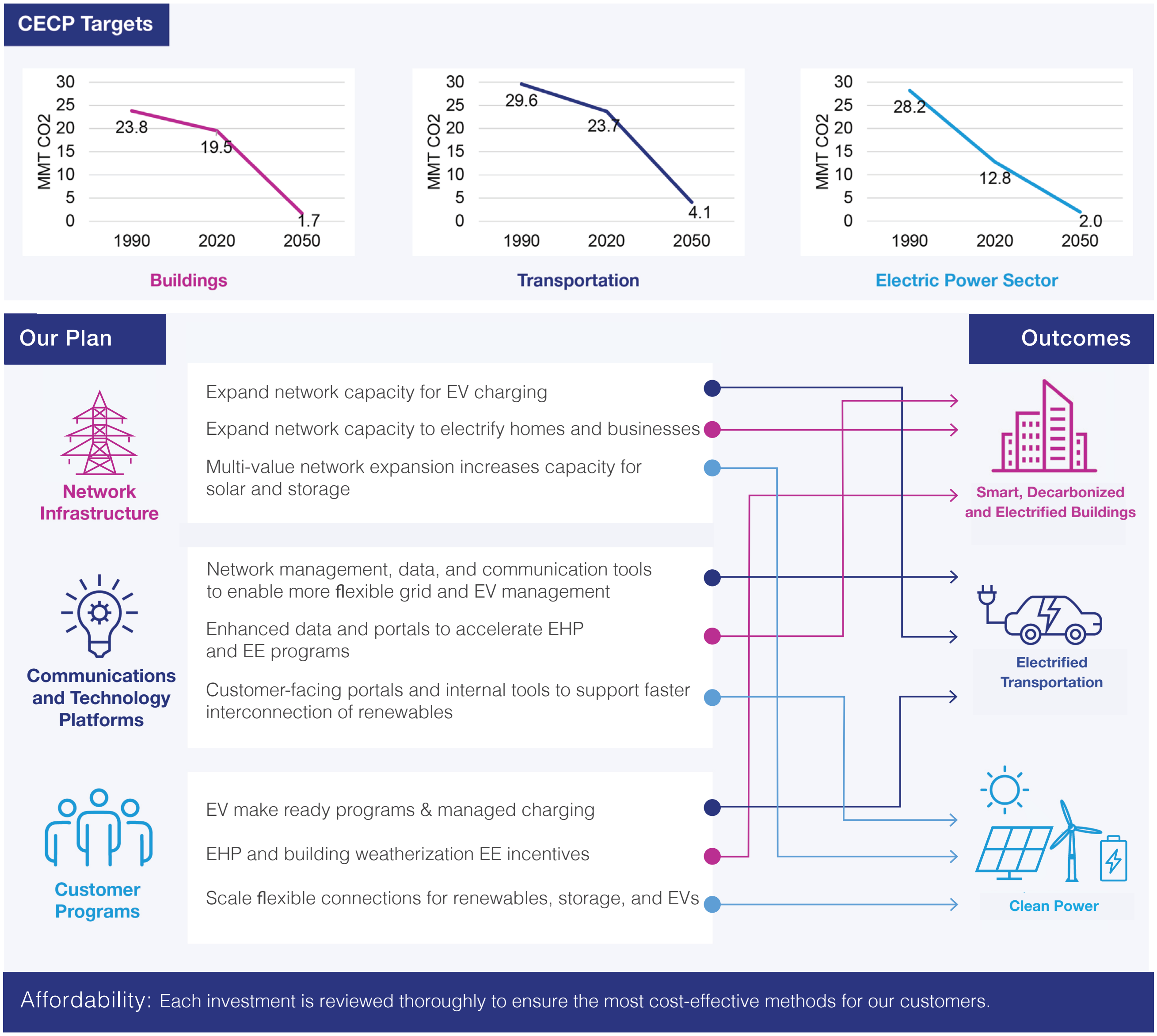
The Company's peak demand is forecasted to more than double by 2050, and shift to the winter in the mid 2030's



System Peak	Summer (GW)	Winter (GW)
2023	4.9	3.7
2029	5.4	4.3
2034	6.3	5.7
2050	8.8	10.7

To meet the 2050 CECP goals and interim milestones, the Company designed an investment plan focused in three key areas: 1) the network infrastructure upgrades and expansion needed to increase systemwide and local network capacity and strengthen the system, 2) the communications and technology platforms necessary to optimize DER, including local solar and storage, and smart end-use technologies for grid benefit, and 3) customer programs to support accelerated adoption of clean, electrified technologies. The graphic below illustrates the 2050 CECP's sectoral emissions reduction goals, and how the Plan's elements map to those goals. Section 5: 5- and 10-Year Electric Demand Forecast provides more detail into how the plan achieves 2050 CECP goals.

How The Company's Future Grid Plan Elements Map to CECP Goals



This Plan links the Company's planning efforts together into an innovative, holistic roadmap for the near term and long term. The Company used an efficient and forward-thinking planning process to develop a coordinated sequencing of network infrastructure improvements with available electrification and hosting capacity for every year within the 10-year forecast period, based on an electric forecast synced to the Commonwealth's clean energy plan. National Grid will continue working with policy makers on future iterations of climate and clean energy policies and evolve its long-term planning for future ESMPs, accordingly. Future proposed investments will be reviewed to ensure that long-term infrastructure buildout is appropriately sized and can maintain high levels of reliability, support accelerated customer adoption of clean technologies, and manage overall costs.

As a significant portion of the Commonwealth's decarbonization will result from the electrification of gas customers, increased coordination is required between gas and electric utilities in the Commonwealth. Data sharing and increased mutual understanding of gas plans developed by gas local distribution companies ("LDCs") and electric plans developed by the EDCs is a necessary first step to enable this coordination, with the ultimate objective being coordinated EDC-LDC long-range capital planning, in compliance with the directives from the Department in its recent Order 20-80-B. Pending Department review of the stated objectives in Section 11: Integrated Gas-Electric Planning, which outlines proposed process, and approvals of investments in the people, data analytics, tools and technologies necessary to successfully execute on integrated energy planning, the EDCs will: (1) proceed with establishing the Joint Utility Planning Working Group, including reporting out to GMAC on an agreed upon cadence; and (2) pursue near-term opportunities to engage in IEP, such as EDC-LDC collaboration on non-pipe alternatives and targeted electrification pilots.

1.3 Service Territory Overview

Our customers and communities are at the foundation of what we do and why we do it, and they are critical to the success of the Commonwealth's decarbonization plans. We must understand their expectations, circumstances, and energy needs as we evolve today's energy network, and plan and build for the future.

Customer Characteristics

Today, National Grid provides electric service to more than 1.3 million customers in 172 towns and cities, across a service area that spans approximately 4,625 square miles — from the Berkshires to Brockton and Cape Ann to Cohasset. We are the electric provider in many of the Commonwealth's Gateway Cities, and we serve many EJCs, representing customers in municipalities such as Adams, Worcester, Somerset, Lowell, Lawrence, Lynn, and others. We serve rural, suburban, and urban areas — including coastal and mountainous communities. Our customers live in single-family homes, multi-family homes, and apartment buildings. They run farms, small retail businesses, restaurants, grocery stores, food processing facilities, and more. They include municipalities and schools, ports and transportation hubs, academic institutions, manufacturing facilities, hospitals, healthcare, and life sciences.

Today's electric system characteristics and what the system delivers

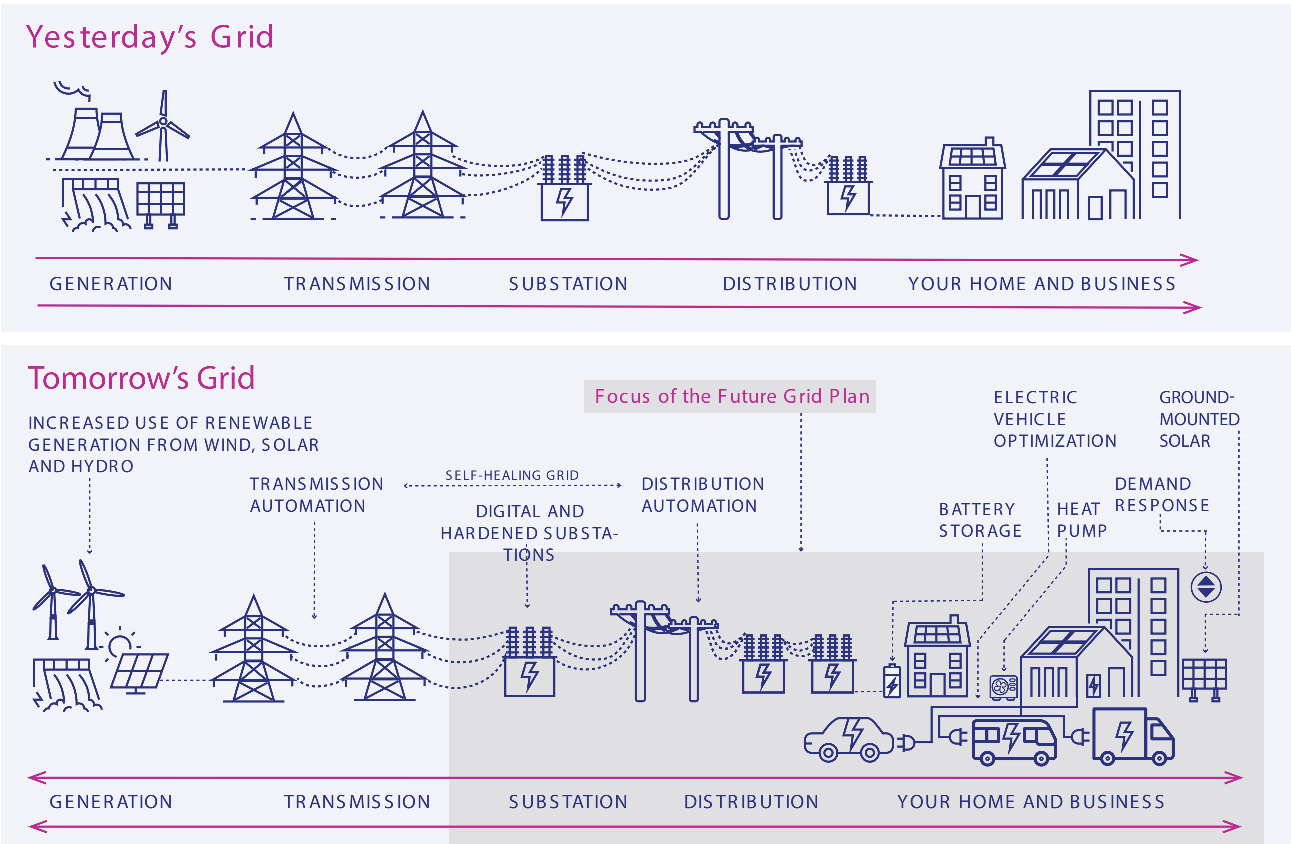
Beginning in the 1910s, electrification expanded rapidly in Massachusetts as electric lighting, industrial applications, and, by the 1920s, residential refrigeration became commonplace. In the 1950s and 1960s, the electric systems continued to expand, fueled by significant economic growth. Concurrently, many municipal- owned and small utilities consolidated into larger utilities. In 1962, nearly 100 small companies consolidated into the Massachusetts Electric Company (MECO). The company remained relatively stable until 2000, when it merged with the Eastern Utility Association. As a result, the Company's current electric distribution system consists of infrastructure with different voltage levels, asset types, and a pattern of "overlayed networks."

To serve our diverse, existing customer base, National Grid operates and maintains an electric network consisting of more than 2,500 miles of electric transmission lines that carry electricity long distances at high voltage levels to transmission substations, which step down this power to a lower voltage, making it safe to carry it across 18,500 miles of smaller electric distribution lines. These lines are supported by hundreds of thousands of poles and 264 strategically located distribution substations. Substations play a pivotal role in stabilizing the entire electric network and maintaining safe and reliable service. Substations must be located close to the load they serve; the median number of residential customers served per substation is 4,000 in the Company's electric distribution network, with a range of approximately 100 to 56,600 depending on its capacity rating. These substations can safely operate indoors or outside and do not emit pollutants that impact local air quality.

Once power is stepped down to appropriate voltage levels, electricity is distributed across a series of lower voltage circuits or wires, which run overhead or underground. This power is then stepped down again at smaller transformers close to homes and businesses and safely delivered to customers.

For more details on the current state of the distribution network, please see Section 4: Current State of the Distribution System. This extensive network will need to nearly double in size and capacity over the next twenty years, including expanding existing substations and adding a substantial number of new substations, while making it smarter by deploying technology to allow for two-way power flows and greater visibility into grid connected technologies like solar, storage and EVs to leverage them as grid assets, and maintaining the overall reliability, stability and safety of the network for all customers.

The Commonwealth's Power Grid – Yesterday and Tomorrow

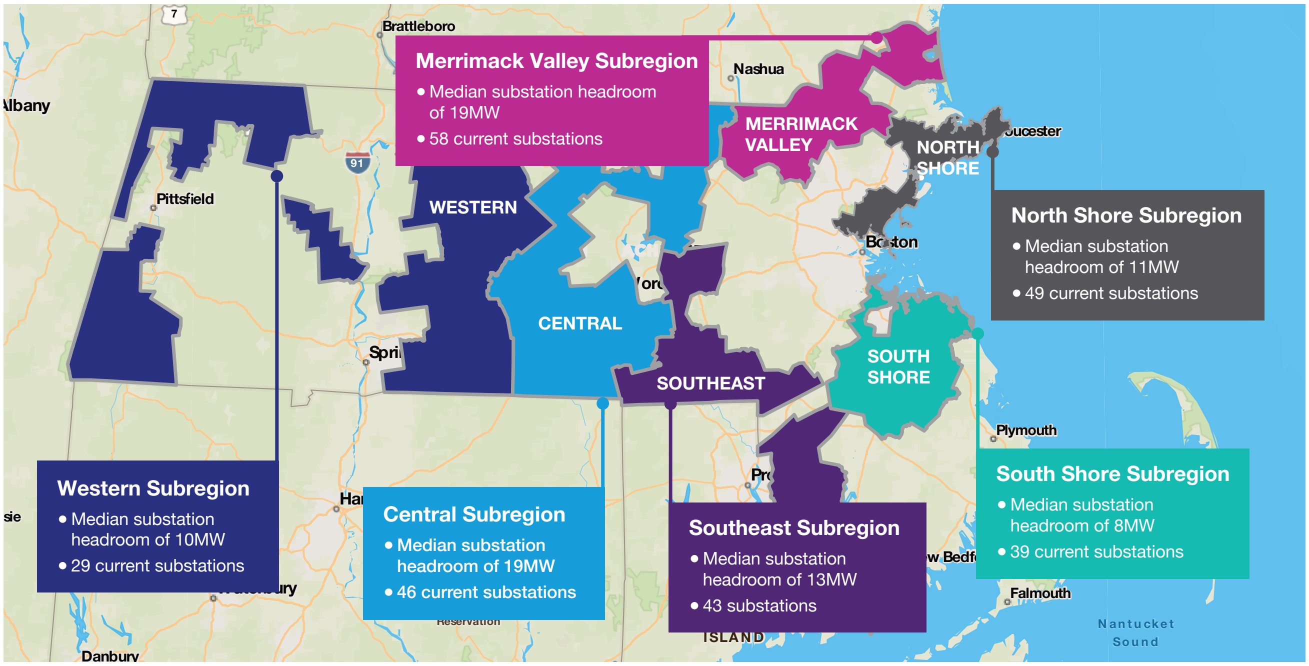


Our community characteristics drive today's system and tomorrow's investments

The diverse communities we serve have unique physical, economic, and historical characteristics that have informed the Company's previous planning criteria and operations. For example, some communities previously supported the Commonwealth's textile and manufacturing economy, while others had limited economic activity. Some rural areas are now becoming suburban, and urban areas that once thrived may have experienced limited growth for a long time. The results of these varied and uneven economic development and settlement patterns across our service area mean that existing infrastructure and system capacity are also varied and uneven.

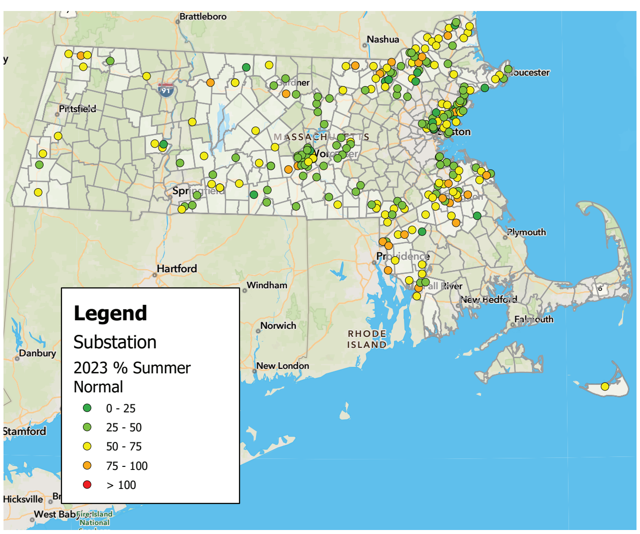
This foundation shapes and informs the investments needed to enable the clean energy transition and build resilience in each community. As we developed our Future Grid Plan, we took both high-level and granular views of our system, breaking it down into six different distribution sub-regions. These groupings are based on both geographic proximity and electrical system characteristics, which facilitate effective system planning and engineering analysis. The map below provides an overview of these six regions and current median substation capacity availability.

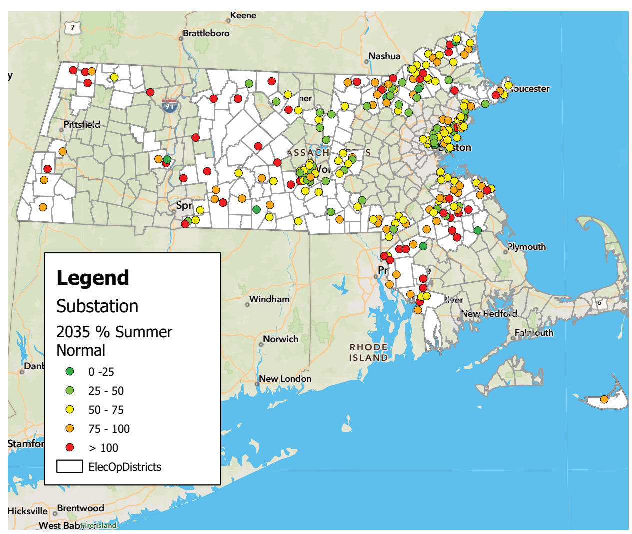
National Grid's Six Major Service Sub-regions



The Company analyzed the current demand, future needs, and existing system capacity in each of these sub-regions. **The maps below show that without any system upgrades, by 2035, every sub-region in our system will see forecasted demand that exceeds current capacity**.

Substation load as percentage of capacity across the Company's, 2023 vs. 2035 forecast assuming no capacity expansion





The scale, scope, timing, and exact locations of investment needs are driven by a combination of factors, including 1) the physical and operational needs and the condition of the infrastructure used to serve these sub-regions, 2) the available capacity on the local electric network to meet future electric and economic development needs and enable DER, and 3) the current performance of the local network as it relates to reliability and resilience. This assessment provides the baseline for examining alternatives, including the use of NWAs, as the Company worked through the planning process. Refer to Section 5: 5- and 10-Year Electric Demand Forecast for more detailed information on our forecasting process and Section 6: 5- and 10-year Planning Solutions for more on our planning process.

1.4 How Customers Will Experience the Just and Equitable Clean Energy Transition

The future electric system will power all aspects of daily life -- appliances, electronics, lighting, cooling systems, cooking, heating, and transportation. Today, our customers rely on and use electric and gas networks as well as delivered fuels to meet their home and building energy needs, and a vast network of fueling stations for their cars, buses, and trucks. In the future, customers will become much more reliant on the electric network as their primary energy system, which will be more decarbonized, more digitized, and more decentralized. As depicted on page 3, customers will have more options and access to technologies and programs that can increase home comfort, convenience, and resilience, lower overall energy costs, and create potential revenue streams from grid connected devices, including appliances, cars, solar and storage.

National Grid customers are increasingly aware of this future and engaged in their energy experience. As a result, they have understandably high expectations for levels of service and options. They want immediate solutions when problems arise, when outages occur, and when opportunities emerge. Rising prices, supply security concerns, and climate change are front of mind. There are more active energy consumers seeking more interaction, driving a greater need for change in the customer experience. Each customer has unique needs, depending on a variety of factors, including customer type, electric use patterns, geography, income, and access to technology.

Affordability and equity also mean different things to different customers. For some business customers, electric costs may be a significant share of their overall operating costs, impacting profitability. For some residential customers, paying their monthly electric bill may require hard choices, such as choosing between heating or eating, because their energy burden is so significant, which is often exacerbated by distributional and structural inequities. We are aware of these key differences and are re-envisioning how we approach, interact with, and serve each set of customers. This deeper understanding of our customers' diverse needs helps us define the investments required to: improve operational efficiency; optimize our plans and programs to build only what is needed to meet reliability, resilience, and growth goals; and enable rate designs, energy efficiency, access to clean transportation, and customer and community-facing programs for bill management and other support.

Transparency, Equity, and Engagement

To best understand how customers want to experience the clean energy transition and their expectations and needs for the future, National Grid is engaging with and listening to its customers and establishing an inclusive, equitable stakeholder engagement process. Submission of the Future Grid Plan to the GMAC in September 2023 was an important step in increasing the transparency and inclusiveness of the Company's investment decision making and reaching a broad range of customers and representatives of impacted communities. National Grid and the other EDCs collaborated with the

GMAC to gather further feedback on their respective ESMPs, which was incorporated into this filing, and gained additional insights through the two stakeholder workshops held in November 2023, along with a dedicated technical session with DER providers in December 2023.

National Grid also met with more than 80 municipalities, 10 business organizations, 7 state agencies, 20 community & nonprofit organizations, labor organizations, representatives of EJCs, energy assistance providers, organizations representing generators, renewables, DER providers, EV providers, housing developers, and others prior to making this submission to the Department (please see the Appendix for a full list). Finally, National Grid maintains a Customer Council comprised of all customer classes, service area communities, and impacted populations, including EJCs. In anticipation of our ESMP filing, we engaged customers through the Customer Council about their expectations for the future energy system. Feedback received through theses engagement is outlined in more detail in Section 3: Stakeholder Engagement and was used to inform this Future Grid Plan.

Key takeaways from our engagement

Build a Grid that Works for Everyone and Empowers Customers

Strengthen our system

A deliberate and equitable transition and meaningful engagement

Keep Costs Down

An affordable and reliable energy system

Put Customers in Control

Easier access to the system, and an improved and quicker connections process

Create a Seamless Experience

Financial and technical support to pursue clean energy and energy efficient solutions

1.5 Demand Assessment and Investment Drivers

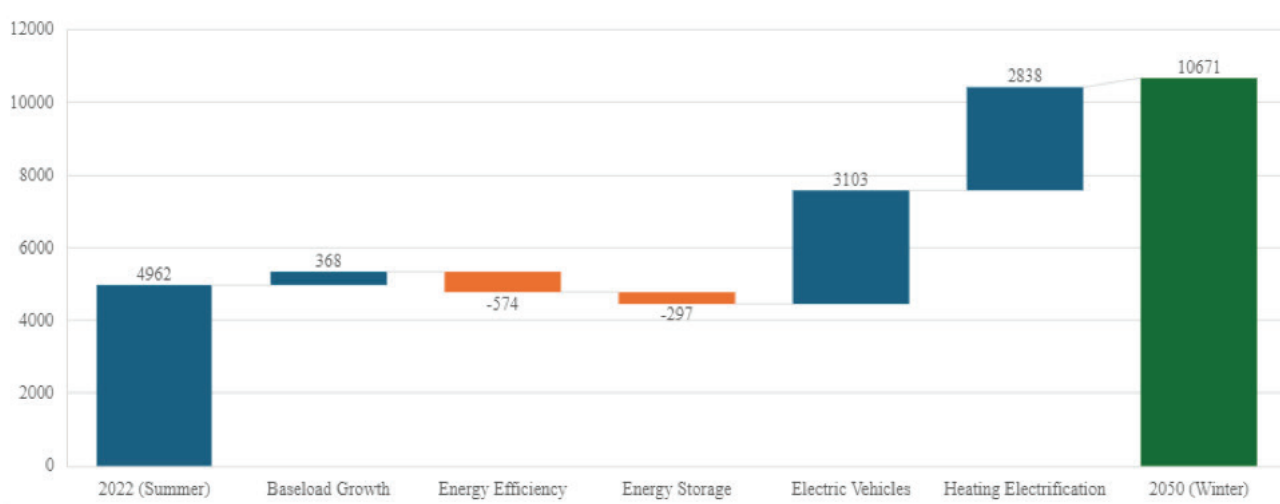
National Grid uses sophisticated modeling tools and a dynamic process to forecast future electric demand, including understanding the drivers and timing of demand. The Company employs an econometric model to first project a base load estimate. It then incorporates adjustments to this base load forecast to reflect policy changes, technology innovation and adoption, customer behavior, and historical load and weather data with other factors to develop a predictive load forecast model. Finally, the Company runs 2000 different scenarios of future electric load growth, including system-level and substation-level peak demand for purposes of investment planning and prioritization.

This integrated and iterative forecasting approach is a prerequisite to efficient capital investment decisions by pinpointing where constraints on the distribution system are projected to manifest. The Commonwealth faces an inflection point in electricity demand. Over the last 15 years, peak electricity demand has remained relatively flat despite increases in base load, due to offsetting energy efficiency actions taken through, for example, the nation-leading Mass Save program, demand response, and support from rooftop solar. However, over the next 10 years, the acceleration of beneficial electrification and underlying economic growth will outpace these offsetting actions, with electric demand forecasted to begin decades of robust growth.

Based on the in-depth forecasting and modeling, we are projecting a 130% increase in net electric demand in the 10-year forecast period in the areas served by National Grid. By 2050, total peak demand, which is the maximum demand on the system in a given year, will increase from a 4.9 GW current summer evening peak to a 10.7 GW winter morning peak. (For more details on the electric forecast, see Section 5: 5- and 10-Year Electric Demand Forecast.) Investments in the next five to ten years must be made with an eye toward the future to ensure that the system is ready to accommodate the expected increases in peak demand associated with the 2050 goals and interim targets, and the season in which the peak will occur. A winter peaking system has different operational characteristics and needs than a summer peaking system, which is a significant consideration in overall system and resource planning and associated investments.

The graphic below provides a breakdown of the components of forecasted load growth, at peak, including the potential impacts of Energy Efficiency (EE) and Distributed Energy Resources (DERs) such as Energy Storage (ES), Solar Photovoltaic (PV), Electric Vehicles (EV), and Heating Electrification (HE) through 2050. See Section 8: 2035 – 2050 Policy Drivers: Electric Demand Assessment for more detailed discussion of the 2050 demand assessment.

Annual peak load growth through 2050 by components



As illustrated, due to a shift to winter peak, PV does not play a material role in reducing peak demand, and even with demand reduction benefits of EE and ES, the Company must accelerate its pace of network investments and operational planning to meet the forecasted capacity needs. Without the necessary investment, the accelerated rates of electric end-use technology adoption to meet the 2050 CECP interim targets will outpace the grid's ability to keep up with demand by 2030 in a manner that preserves system reliability for all customers.

1.6 5-year Electric Sector Modernization Plan Investment Summary and Outcomes Achieved

This Plan builds on investments already underway to modernize the grid and complements the investments the Company continues to make to provide safe and reliable service, as approved in our periodic base rate reviews with the Department. For a comprehensive review of the investments already approved and/or pending by the Company, please refer to Chapter 6: 5- and 10-Year Planning Solutions: Building for the Future.

The Company has Capital Investment Projects (CIP) pending before the Department to support additional DER capacity. The Company recently filed it's Base Rate Case (BRC) for the Company to support the core investments needed to safely and reliably operate the electric distribution network, meet current customer demand, improve the overall efficiency and resilience of the system, and provide a more seamless experience for customers and those connecting to our system. The investments in the CIPs and BRC filing are core investments that establish the foundation for the incremental investments proposed in this Future Grid Plan that are necessary to meet the 2050 CECP goals and interim milestones. The Future Grid Plan comprises:

- **Network Infrastructure Investments:** New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology to improve network operations and management.
- **Communication and Technology Platform Investments:** Technology investments to accelerate and support the transition to a clean energy-heavy grid, including network management technologies (including DERMS), telecommunications, cybersecurity, data management, and new digital products to support asset management, technology, and operations.
- **Customer Program Investments:** New programs and demonstrations to advance VPPs and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies.

Proposed 5-Year ESMP Investments (2025 to 2029) and CECP-related Outcomes

Over the next five years, through this Future Grid Plan the Company proposes to invest approximately $2.5B to support the network infrastructure, communications and technology platforms, and customer programs necessary to meet the 2050 CECP goals and outcomes. These network infrastructure investments, coupled with investments in communication and technology platforms to expand and enhance network management tools, customer programs, enterprise-wide network communications, planning data management capabilities, and customer-facing portals will enable an additional 1 GW of solar capacity, 492,000 EVs, and 84,000 electric heat pumps, keeping the Commonwealth on pace to meet its cumulative 2030 and 2050 targets.

Existing Base Rate Case and Active Regulatory Investment Summary

Category	Summary	Recovery
Base Rate Case	Electric operations to ensure safe and reliable service including: • Asset repair and maintenance • System capacity and performance projects • Damage/Failure projects required to replace damaged equipment • New customer connections • Non-infrastructure such as IT, fleet, etc.	Base rate recovery
Active Regulatory Investments	• AMI • EV make-ready charging • Capital Investment Projects (CIPs) • Grid Modernization	Individual projects filed with DPU, Grid Mod Mechanism (through 2028), EV mechanism (through 2026)

Proposed ESMP Investments 2025 – 2029

Category	Summary	Recovery	CapEx ($M)	OpEx ($M)
Network Investment	• Substation and distribution line upgrades/expansion for electrification load growth and DER interconnections • Pending DER interconnections with cost allocation (including 3 CIP projects)* • Installation and management of additional technology to improve the network capabilities	Incremental ESMP	$1,533	$58

Platform Investments	Network management technologies (incl. DERMS) Telecommunications Cybersecurity Data management New digital products to support asset management, technology, and operations for a DER-heavy grid	Incremental ESMP	$323	$77
Customer Programs	New programs and demonstrations to advance VPPs and DER for grid services Customer portals to enable clean energy and electric end use adoption Continuation of existing EV make-ready and charging infrastructure programs		$84	$315

*In addition to the costs in this table, the Company also projects expending $71 million in capital and associated operating and maintenance costs for new CIPs.

Using NWAs to manage costs, maintain reliability, and drive innovation

As the Company conducted its system planning assessment and subsequent investment decision-making, it actively pursued opportunities to apply NWA solutions to meet distribution system needs in both the 5- and 10-year plans, including:

- **Bridge to Wires NWAs**. Solutions that can be deployed quickly in the highest needs locations to address an imminent need where a capital project cannot feasibly be delivered in the timeframe.
- **Deferral NWAs**. Solutions to defer substation projects from 2029 through 2034. Pilot programs were selected in areas where load growth is more manageable and capital projects can be implemented quickly should NWAs not materialize.

The NWA solutions proposed in this Plan serve as a first step in a multi-year process to develop and mature NWA capabilities. These initial NWAs will provide significant learnings on the capabilities of NWAs to reliably meet customer and system needs, including aggregated solutions such as Virtual Power Plants (VPPs) that can provide utility-scale grid services. The Company has several teams committed to successfully enabling NWAs with focus on 1) creating connections with leading technology developers and 2) transformation mapping of internal capabilities to test and scale avoided infrastructure investment with a specific goal of bill reductions. For more details on our NWA plans, see Section 6: 5- and 10-Year Planning Solutions.

The Company will pursue an NWA in the area surrounding Litchfield Street station in Leominster to defer a feeder expansion project. The proposed NWA is comprised of a combination of targeted EE, DR, managed charging incentives and market-based flexibility auctions, essentially creating a VPP to meet load during peak periods.

Importantly, the success of future, expanded use of NWAs is dependent on the timely implementation of the Company's Communication and Technology Platforms and Customer Programs proposed in this Future Grid Plan and other in-flight system modernization and customer program efforts, including Mass Save, AMI, and the deployment of Distributed Energy Resources Management Systems (DERMS), which will allow the Company to actively manage the DER connections that make up NWA solutions.

Plan implementation will be transparent and inclusive

To promote a more resilient system and properly plan for and address the Commonwealth's energy needs, clean energy infrastructure must be deployed in a timely manner in communities across the state, including those that currently host major energy infrastructure and those that historically have not. The Company's Plan includes expanding or building new substations in dozens of municipalities over the next five to ten years. Key to successfully executing these projects is to ensure host communities have input and agency throughout the process.

Stakeholder engagement is foundational to a just and equitable energy transition. To further enhance its stakeholder and community engagement, National Grid and the other EDCs are proposing the development of a Community Engagement Stakeholder Advisory Group (CESAG). The primary objective of this group is to develop a community engagement framework, centered in equity, that can be applied to major infrastructure projects related to the clean energy transition before they are submitted to the Department and/or the Energy Facilities Siting Board (EFSB). Additionally, as outlined in Section 3: Stakeholder Engagement, the Company developed an Equity ad Environmental Justice Policy and Stakeholder Engagement Framework (Framework) based on building engagement in partnership with stakeholders that have not historically participated in the project development process and regulatory proceedings.

This Framework was informed by principles developed by the American Council for an Energy Efficient Economy (ACEEE) and rooted in enhancing 1) Procedural, 2) Distributional, and 3) Structural equity. National Grid proposed this Framework in its September submission to the GMAC and revised it to reflect feedback from the GMAC Equity Working Group and other stakeholders prior to finalizing and submitting it with this filing. Successful implementation of a repeatable framework will increase the efficiency and transparency of execution of major infrastructure projects while ensuring community feedback is reflected. In addition to such a community engagement framework, major siting and regulatory reform is also necessary to ensure timely construction of the infrastructure necessary to maintain safe and reliable service in a decarbonized future.

1.7 Climate Impacts and Building Resilience

Climate change is affecting the Commonwealth's weather in dramatic ways, today. Historically, National Grid's system could expect four major storm events with significant outage impacts each year; now the expectation has risen to 10 storms per year. These storms can also be more intense and localized, creating wind and flood damage. Higher summer temperatures and humidity levels are generating multiple effects, including increased customer cooling saturation rates, higher cooling usage, higher summer peaks, and de-rating of transformer capacity. Winters, while milder on average, are also subject to 'polar vortex' conditions that bring intense cold and snow, with corresponding outage risks and peak demand impacts. While National Grid has maintained reliability at levels exceeding 99.9% of system-wide availability, we recognize that such climate impacts present risks to sustaining these levels.

At the same time, the Commonwealth's climate and clean energy goals add potential system reliability risks as we integrate more large-scale renewable resources, DERs, including local solar and storage, and new loads from beneficial electrification. Distribution system resilience and reliability must address these among other contributing factors. National Grid has developed robust processes to respond to impacts on distribution system performance. Additionally, preparing for and responding to the potential impacts of climate change is embedded in the way we plan, construct, and operate our system.

To make our system stronger and better able to withstand more severe and frequent weather events, our BRC filing includes investments to increase system resilience and maintain high levels of reliability. Investments focused on reliability and resilience are considered core, or foundational, by the Company and, as such, were primarily included in our BRC. The investments which comprise the Future Grid Plan are proposed to address electrification-driven load growth and will provide a secondary benefit of improving reliability and resiliency of the distribution system, we took opportunities to also strengthen and make the system more resilient. For example, where the Company proposed upgrades as part of this Plan to ready the network for electrification demand growth, we also took advantage of the opportunity that upgrading the network offers to do things like, for example, adding Early Fault Detection technology.

To identify climate hazard risk, the Company applied a Climate Vulnerability Assessment (CVA), which is an innovative approach to mapping our electric infrastructure to potential climate hazards – such as floods, and heatwaves, and high winds. As our understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of the Company's processes will allow additional measures to be developed and implemented. Our overall approach to system reliability and resilience is summarized below, with more detail provided in Section 10: Reliable and Resilient Distribution System.

The Company's distribution system reliability and resilience initiatives

Distribution Construction Standards	Regular reviews and updates of distribution construction standards to address climate-related changes and its impact on system reliability performance.
Vegetation Management	Developing long-term strategy, planning, budgeting, and delivery of the vegetation management work plan to address vegetation impacts on safe and reliable service.
Asset Management Practices and Distribution System Planning	Practices and studies to identify existing and projected future system performance concerns and the infrastructure development required to address them.
Infrastructure Development Programs	Programs designed to address the addition, replacement, and/or modification of specific assets.
Distribution Resiliency Hardening Programs	An approach to identify, prioritize, and mitigate Company circuits that have demonstrated historical resiliency challenges with a focus on hardening assets to increase the resiliency of the distribution system.
Asset Climate Vulnerability Assessments	An approach to consider the impacts of climate change over the next several decades to determine future risk to our built and future electric infrastructure. Identifying climate hazards including flooding, heat waves and high temperature, extreme wind, ice accretion, and wildfires.

1.8 Workforce and Societal Benefits of a Just Transition

The Future Grid Plan will enable a variety of economic, environmental, climate, health, and system benefits that will be realized at local and state levels through incremental economic activity and job creation, GHG emissions reductions, improvements in air quality, greater system safety, and resilience. All EDCs used a single third-party with a common methodology to produce the net benefit assessment, as recommended by the GMAC. In addition to monetizable benefits, the Plan's investments provide many non-monetizable benefits which support the Commonwealth's climate and equity goals. Importantly, the investments proposed in the 5-year plan are expected to have a cumulative reduction in GHG emissions of 31.3 MMT. A high-level summary of the overall benefits delivered are included below, with detailed information regarding the net benefits assessment provided in Section 12: Workforce, Economic, and Health Benefits:

- **Enhancing safety**. As the Company designs, builds, or maintains assets, we consider opportunities to enhance system safety. For example, investments to replace aging infrastructure, eliminate older equipment that has a higher operational risk profile than the current technology, and technologies that minimize or avoid service disruptions all contribute to improving employee and public safety.

- **Expanding stakeholder engagement and increasing transparency.** The Company's new Equity and Environmental Justice Policy and Stakeholder Engagement Framework, coupled with the proposed CESAG, will ensure a diverse group of interested stakeholders is proactively engaged and has a voice on a just transition to enable clean energy and the Company's proposed Future Grid related projects.

Benefit Type	Amount Expected (2025-2029)
Total Estimated Benefit	NPV of $821 Million
Emissions Abatement	31.3 MMT of CO2; 7,460 MT of NOx; 160 MT of PM2.5
Jobs Creation	3,900 full and part-time jobs
Economic Impact	$500 million in incremental economic activity

- **Enabling grid reliability and resilience**. Substation and feeder expansion and upgrades, deployment of new technology, and evolution of planning criteria and related investments will drive improvements in the Company's existing reliability performance. As described in Section 10: Reliable and Resilient Distribution System, the Company is also employing its innovative CVA to identify and mitigate climate risk hazards. Outside of this Plan, the Company has proposed resilience and reliability investments as part of its BRC, including the continued deployment of Reclosers and FLISR technology to reduce outage duration by up to 55% for impacted customers, and avoid disruptions by expanding our proactive vegetation management program and deploying tree-resistant wires.

- **Facilitating electrification of buildings and transportation.** As a result of the Plan, at the end of the 10-year period, the Company will have increased the headroom of the system to meet peak demand of 6 GW, which is 25% higher than today, keeping the Commonwealth on track to meet its EV goals of 870,000 million vehicles on the road by 2035 and 235,000 electric heat pumps in homes and businesses. This effort will be complemented by energy efficiency and demand response programs administered by the Company through Mass Save to minimize demand along with managed charging programs to help mitigate peak loading impacts of EVs. Over time, the use of AMI, which begins roll out in 2024, will provide an additional tool to empower customers to actively participate in energy programs and manage their energy usage and costs, including through time-varying rates.

- **Connecting and integrating DER**. The Company has a longstanding commitment to improving the interconnection process and implementing projects to facilitate the integration of DER on its system. In total, the Company has connected more than 2.3 GW of DER and this Plan will support the connection of another 2 GW, essentially doubling the DER capacity on the electric distribution grid, and providing expanded opportunities for NWAs and other innovations.

- **Reducing greenhouse gas emissions and air pollutants**. The Company's 5- and 10-year plans will contribute to the Commonwealth's GHG emission reduction goals. Capacity expansion and grid modernization will enable increased penetration of renewable energy and a shift away from fossil fuel generation, which will ultimately lead to reductions in GHG emissions and air pollutants. The net benefit modeling estimates that the Future Grid Plan will enable a reduction in CO_2 emissions of approximately 31.3 MMT, NO_x emissions of 7460 MT, and PM2.5 emissions of 160 MT.

- **Increasing economic activity and creating jobs**. The substantial investments necessary for the transition toward long-term GHG reduction goals will result in positive economic benefits. As described in Section 12: Workforce, Economic, and Health Benefits, the Company utilized United States Department of Commerce Bureau of Economic Analysis ("BEA") Regional Input-Output Modeling System II ("RIMS II") to assess the potential economic impacts of the Future Grid Plan.

  The modeling forecasts approximately $500 million of incremental economic activity from the Future Grid Plan capital expenditures during 2025 – 2029 and $1.1 billion over the 10-year plan. The modeling also forecasts approximately 3,900 full- and part-time jobs from 2025 through 2029, and more than 8,700 jobs during the extended period of 2025 through 2034 from the Future Grid Plan. Inclusive of the Company's BRC, which is foundational to ESMP investments, CIP proposals, and this Future Grid Plan, the modeling forecasts approximately $1.7 billion of additional economic activity from capital expenditures during 2025 – 2029 and more than $3.5 billion over the 10-year plan. The modeling also forecasts more than 13,100 full- and part-time jobs from 2025 through 2029, and approximately 28,000 jobs during the extended period of 2025 through 2034, inclusive of these investments.

  In addition to the direct expenditures associated with the proposed network investments, increased construction activities and infrastructure build-out will have positive tax and revenue impacts for some communities that host the planned infrastructure.

Workforce, Economic Opportunity, and a Just Transition

The Company is committed to training and hiring the future workforce and creating economic opportunities in historically underrepresented communities.

The jobs created through these investments are significant and include a mix of shorter duration work to support the build out of the network, and ongoing operational support. They also include jobs that support the planning and engineering of the system, the operation and management of grid performance, communications and IT platforms, and the design and implementation of customer programs that support the electrification of heating and transportation, DER deployment and energy efficiency.

The energy transition offers an opportunity to provide career pathways to local communities – particularly those that have not historically benefited from — or have been burdened by — such investment. To enable this and meet the significant need for a ready, available, and skilled workforce, National Grid launched a multi-pronged workforce development pilot program, focused on underrepresented communities, to provide the foundational training and education to create a talent pipeline from these communities.

The Company's workforce development strategy is built around four strategic pillars:

- Work-ready adults ready to reenter the workforce;
- College/university graduates starting their careers;
- Traditional and vocational technical high school students passionate about learning in-demand skills; and

- Middle schools that promote STEM awareness of the Commonwealth's climate and clean energy goals.

National Grid launched its strategic Workforce Development Program (WDP) and pilot in March 2023. To date, more than 30 individuals have secured employment with the Company or its contractors, helping to build generational wealth for them and their communities. Our WDP was developed in partnership with community-based organizations, community colleges, universities, vocational and technical institutes, and middle and high schools, and is being implemented in coordination with efforts already underway by the state, including the work of the Massachusetts Clean Energy Center (MassCEC) and funding from the state through a STEM-Tech grant and from the federal government through the Infrastructure Investment and Jobs Act.

Equity, Environmental Justice, and Affordability

Being fully cognizant that affordability is a major concern for all customers and communities, the Company will continue to support efforts to ensure that cost impacts are correlated with the benefits that accrue from improved reliability, resiliency, and clean energy investments and programs. The Company believes both the pace and scale of the proposed investments in this Plan across network infrastructure, communication and technology platforms, and customer programs are both appropriate and necessary to achieve the Commonwealth's 2050 targets and interim mandated milestones.

The investments proposed in the Future Grid Plan are projected to result in an estimated $3 per month by the end of the 5-year investment period.. We understand that any cost increase can be a challenge for customers and that many lower-income customers may be disproportionately impacted. To address this, National Grid proposes to alleviate energy burden for its distribution customers through a tiered discount rate, which is pending before the Department as part of the Company's BRC filing, along with an expanded customer outreach and engagement program. This tiered discount program aims to keep energy burdens for eligible customers at no more than 6% of their total annual income by offering discount rates that would reduce an eligible customer's bill by up to 55%.

To the extent that the Department supports a different balance between the pace of proactive investments designed to meet the Commonwealth's 2050 CECP goals and overall affordability for customers, the Company has provided an assessment of the tradeoffs between investment pace and projected outcomes in Section 7: 5-Year Electric Sector Modernization Plan, which is underpinned by detailed analysis. The Company also recognizes and appreciates that the Department recently opened an inquiry to examine energy burden with a focus on energy affordability for residential ratepayers (D.P.U. 24-15). We look forward to actively participating.

1.9 Conclusion and Next Steps

The Commonwealth's 2050 CECP is an equity-centered plan rooted in decarbonizing electricity and using this clean energy to power all aspects of the economy. Meeting the 2050 CECP goals requires all the Commonwealth's EDCs to develop comprehensive, thoughtful, and flexible plans that transform today's electric distribution grid, giving it new capabilities and expanding it at pace and scale to support this future, which will result in a doubling of electric demand over the next 25 years.

By developing and submitting this Future Grid Plan, the Company is taking an important step to defining the comprehensive scope and scale of what we collectively must do over the next 5, 10, and 25 years to combat climate change and enable a more electrified and equitable energy future. We are doing this by identifying the system investments and changes needed in the electric distribution system to meet growing demand, engaging broadly to stimulate ideas, seeking input to ensure our investments are responsive to and supportive of the needs and expectations of all our customers and communities, and making it easy for customers to adopt the clean energy choices that work for them and their budgets.

Since release of the final GMAC recommendations and stakeholder workshops in the fall of 2023, the Company has worked to update this Plan to be responsive to feedback gathered, to date. As a part of the roadmap, in the near term, the Company contemplates: further work to stand up the CESAG to improve the process for efficiently soliciting and responding to stakeholder feedback; support for the Department's inquiry into affordability and rate design; and further efforts to gain alignment on the metrics and reporting required to ensure transparency in ESMP implementation efforts. Collectively, these next steps will improve the transparency and effectiveness of ESMP implementation and empower Massachusetts by building a smarter, strong, cleaner and more equitable energy future.

Section 2
Compliance with the EDC requirements outlined in the 2022 Climate Act

This section summarizes the statutory requirements and objectives for the ESMPs outlined in the 2022 Climate Act and explains how the Future Grid Plan addresses them.

Section Overview

The Company's Future Grid Plan (ESMP or Plan) has been developed to make meaningful contributions to advancing state climate and energy policy goals 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. Massachusetts has been at the forefront of policy initiatives that support the advancement of clean energy resources, electrification, reliability and resiliency, decarbonization, and climate-driven economic transition. As the Company continues to support the equitable transition to a clean energy future, continued and accelerated investments will be necessary to a much greater degree than recent history in both the electric distribution and transmission systems in order to support these state climate and energy policy goals, and to meet increasing customer demands for safe, reliable, and resilient electricity. National Grid has been an active partner in achieving the Commonwealth's goals, including past efforts focused on grid modernization and distributed energy resource penetration. Prior investments alone are not sufficient to achieve a comprehensive and holistic transition to a decarbonized and electrified economy as envisioned through the Commonwealth's statutes and planning documents including the Clean Energy and Climate Plan for 2050. Accordingly, the Company's ESMP is designed to address all elements of Section 53 of the 2022 Climate Act and propose specific investments and alternatives to investments that will advance the intended purpose of enabling a just transition to a reliable and resilient clean energy future.

2.1. Purpose

In accordance with G.L. c. 164, § 92B(a), the Company's ESMP has been developed to proactively upgrade the distribution system (and, where applicable, the associated transmission system) to: (i) improve grid reliability, communications and resiliency; (ii) enable increased, timely adoption of renewable energy and distributed energy resources; (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (iv) prepare for future climate-driven impacts on the transmission and distribution systems; (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, the transmission system; 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.

The Company's ESMP considers various information in order to propose investments and alternative approaches that improve the electric distribution system in a manner designed to achieve a reliable and resilient clean energy future. These proposed investments and alternatives aim beyond traditional utility maintenance and upgrades, instead focusing on cost-effective solutions for future electrification, renewable and distributed energy resource integration, decarbonization-driven economic and environmental transitions, and customer empowerment.

2.2 Information Considered

The Company's Plan and/or pre-filed testimony describe 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; (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; (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; (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources; (v) improvements to the distribution system that will facilitate transportation or building electrification; (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under Chapter 21N; (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment; (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; 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. 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. Further, in this Plan the Company complied with the requirement to prepare and use three planning horizons for electric demand, including a 5-year forecast, a 10-year forecast 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. G.L. c. 164, § 92B(c)(i). The Company also considers and includes a summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments 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 (GMAC) established in section 92C, responded to information and document requests from said council and conducted technical conferences and a minimum of two 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. G.L. c. 164, § 92B(c)(iii). Specifically, the GMAC began meeting in March 2023 to engage in preliminary governance and informational reviews, and upon receipt of the first ESMPs from all three electric distribution companies (EDCs) on September 1, 2023, the GMAC initiated its 80-day long review of the ESMPs. Overall, the EDCs participated in 26 meetings held by the GMAC or its subcommittees, during which the Company provided requested information, responded to questions, and solicited input on the ESMP. The EDCs responded to three information requests during the GMAC review. The GMAC issued its final report on November 20, 2023, including 88 recommendations for the ESMPs. The EDCs hosted joint stakeholder and technical workshops on November 15, 2023, November 28, 2023, and December 7, 2023, to solicit broad stakeholder input to inform the final ESMP. The Company's ongoing stakeholder and community outreach, as well as details regarding its stakeholder and technical workshops, is discussed in Section 3.3, 3.4, and 3.5 of this ESMP.

2.3. Mapping of Information Presented to Statutory and Regulatory Requirements

The Company is submitting a comprehensive set of pre-filed testimony supported by expert witnesses that address, in detail, how the ESMP meets the statutory requirements noted above. The information required is presented in the table below, along with citations to where such information is presented in the Plan, pre-filed testimony, or both:

Information Required in ESMPs	Citation to Plan and/or Testimony
A summary of all proposed and related investments, alternatives to these investments and alternative approaches to financing these investments that have been reviewed, are under consideration or have been approved by the Department previously	NG-ESMP-1, Sec. 6.4 through 6.10; Sec. 7.1; NG-Policy/Solutions-1, at Sec. VI
Identification of customer benefits for all proposed investments and alternative approaches to financing those investments	NG-ESMP-1. Sec. 7, 7.1.3, 7.1.4 & Sec. 12; NG-Net Benefits-1; NG-Net Benefits-3
Three planning horizons for electric demand, including a five-year and ten-year forecast and a demand assessment through 2050	NG-ESMP-1, Sec. 5.1 & Sec. 8.0; NG-Policy/Solutions-1, at Sec. VII NG-Forecast-1
A list of each GMAC recommendation, including an explanation of whether and why each recommendation was adopted, adopted as modified, or rejected, along with a statement of any unresolved issues	NG-Policy/Solutions-2; NG-Forecast-2; NG-Net Benefits-2; NG-Bill Impacts-2; NG-Metrics-2; NG-Stakeholder-2
Improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks	NG-ESMP-1, at Sec. 4.3.9, 4.4.9, 4.5.9, 4.6.9, 4.7.9, 4.8.9, 6, 7, 9 and 10; NG-Policy/Solutions-1, at Sec. VI
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	NG-ESMP-1, at Sec. 6.3, 7.1, and 9, 9.1, and 9.7; NG-Policy/Solutions-1, at Sec. VI and VIII
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	NG-ESMP-1. Sec. 5.1.5 through 5.5.5 & Sec. 6, 8 and 9; NG-Forecast-1;

	NG-Policy/Solutions-1
Improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources	NG-ESMP-1, Sec. 6.11, 7.1, 9, and 11; NG-Policy/Solutions-1, at Sec. VI to XI
Improvements to the distribution system that will facilitate transportation or building electrification	NG-ESMP-1, Sec. 6.4 through 6.10 & Sec. 6.11; NG-Policy/Solutions-1, at Sec. VI to XI
Improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N	NG-ESMP-1, at Sec. 4.3.5, 4.4.5, 4.5.5, 4.6.5, 4.7.5, 4.8.5, 6.4-6.10, 7.1, 9, 10, and 11; NG-Policy/Solutions-1, at Sec. VI to XI
Opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment	NG-ESMP-1, at Sec. 6.0, 6.11, 7, 9.1.4, and 9.6; NG-Policy/Solutions-1, at Sec. XI
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	NG-ESMP-1, at Sec. 6.4.2.5, 6.4.2.7, 6.5.2, 6.6.2, 6.7.2, 6.8.2, 6.9.2, 6.10.2, 6.11, 7.1.1, 9.1, 9.3, 9.5; NG-Policy/Solutions-1, at Sec. XI
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	NG-ESMP-1, at Sec. 6, 7.1.2, and 9.5; NG-Policy/Solutions-1, at Sec. XI

In addition, the Department is requiring the Company to present the following information through pre-filed testimony:

1. how the ESMP complies with each subsection of G.L. c. 164, § 92B;

2. how the distribution and transmission upgrades identified in the ESMP impact safety, security, reliability of service, affordability, equity, and reductions in greenhouse gas emissions. Such testimony and supporting documentation should clearly distinguish between distribution and transmission system upgrades and related costs;

3. how the ESMP provides net benefits to customers. The net benefits analysis must identify the projected benefits and costs, explain the methodology used, identify all assumptions relied on in the analysis, and address whether, how, and why any factors were prioritized in

the analysis. This net benefits analysis may include both quantitative and qualitative demonstrations of net benefits;

4. the forecast projection and demand assessment methods that addresses how the methods:

    a. are reasonable, reviewable, and reliable; and
    b. inform planned and proposed investments

5. projected bill impacts with one-year, three-year, and five-year outlooks of implementing the ESMPs;

6. the EDC's existing capital planning process(es), demand forecast methods, and decision-making process for distribution system capital investments; and

7. whether, how, and why the ESMP forecasting, timeline, and investment proposal(s), if applicable, differ from the existing capital planning process.

This information can be found in the Company's pre-filed testimony or in additional pre-filed testimony supporting the Plan, as noted in the below table:

Information Required in Pre-Filed Testimony	Citation to Pre-Filed Testimony
Compliance with G.L. c. 164, § 92B	Exhs. NG-Policy/Solutions-1, NG-Forecast-1, NG-Net Benefits-1, NG-Bill Impacts-1
Impact of Proposed Upgrades	Exh. NG-Policy/Solutions-1
Customer Net Benefits	Exh. NG-Net Benefits-1
Forecast Projection and Demand Assessments	Exh. NG-Forecast-1
Bill Impacts	Exh. NG-Bill Impacts-1
Existing Capital Processes, Forecast Methods and Decision Making Process for Distribution System Investments	Exh.NG-Policy/Solutions- 1, at Section VII
Whether/How ESMP Forecasting, Timeline, Incremental Investments Differ from Existing Process.	Exh. NG-Policy/Solutions-1, at Section VII Exh. NG-Forecast-1

In addition to the pre-filed testimony noted above, the Company is submitting pre-filed testimony addressing the following topics in support of its ESMP:

- Stakeholder Engagement: Exh. NG-Stakeholder-1.

- Metrics: Exh. NG-Metrics-1.

2.4 Recommendations for Additional Phases of ESMP Dockets or Generic Dockets to Address ESMP Topics

The 2022 Climate Act requires an extensive amount of information to be included in an ESMP, but limits the Department's review to seven months from the date an ESMP is filed. Moreover, each EDC is required to submit their ESMP on the same date, further complicating the Department's review of these comprehensive plans in such a limited timeframe. In addition, the 2022 Climate Act, contemplates consideration by the Department of several issues that, standing alone, might require far longer than seven months to review. The 2022 Climate Act requires the EDCs to provide a statement of unresolved issues arising from the GMAC's review, input, and recommendations. G.L. c. 164, § 92B(d).

Given the broad scope of issues that the Department may determine warrant consideration regarding the ESMPs and the limited time to resolve all issues through the ESMP process to date, the Company, along with the other EDCs, propose the following:

1. Defer consideration of potential rate redesign options, including time-varying rates, to a generic proceeding, or other dockets currently open to consider such options (e.g., with respect to electric vehicle time-of-use rates, D.P.U. 23-84 and D.P.U. 23-85, and with respect to energy affordability with a focus on residential customers, D.P.U. 24-15);

2. Defer review of opportunities to dispatch energy storage technologies to improve renewable energy utilization and avoid curtailment to the currently open dockets addressing new storage tariffs (D.P.U. 23-115, D.P.U. 23-117; D.P.U. 23-126);

3. Defer review of alternative approaches to financing ESMP-proposed incremental CIP investments to a generic proceeding, and continue to allow EDCs to propose CIPs during the 2025-2029 ESMP term that would be funded pursuant to the Department's D.P.U. 20-75-B cost allocation paradigm; and

4. Defer consideration of ESMP metrics to a different phase of the ESMP dockets, to be commenced after the Department's review of the ESMPs, where proposed metrics can be considered and developed more extensively, consistent with the process used by the Department to date for Grid Modernization and Electric Vehicle Program metrics (respectively, D.P.U. 21-80; D.P.U. 21-81; D.P.U. 21-82; D.P.U. 21-90; D.P.U. 21-91; D.P.U. 21-92).

Each of these recommendations are addressed in further detail in the Company's pre-filed testimony at:

1. Rate Design: Exhibit NG-Policy/Solutions-1, at Section XI.
2. Energy Storage Technologies: Exhibit NG-Policy/Solutions-1, at Section XI.
3. Alternative Approaches to Financing: Exhibit NG-Policy/Solutions-1, at Section XI.
4. ESMP Metrics: Exhibit NG-Metrics-1, at Section V.

Section 3
Stakeholder Engagement

This section describes the Company's stakeholder engagement process to develop the Future Grid Plan, as well as the plan for future stakeholder engagement as the Company transitions from planning to implementation.

Key Take-Aways

- The Company is here to serve the communities where it operates the electric network, and it recognizes that building understanding and trust with all stakeholders (customers, communities, policymakers, public officials, and non-governmental organizations) is critical to a successful clean, fair, and affordable energy transition.
- Throughout the planning process the Company has engaged broadly — the Future Grid Plan reflects that engagement and involvement.
- In conjunction with the other EDCs, the Company has robust plans to continue this engagement so that it can make the investments and choices that its communities want and need.
- The Company is focused on ensuring that the clean energy transition benefits all, especially those communities which have historically experienced a disproportionate impact from the fossil-based economy.

3.0 Stakeholder Engagement

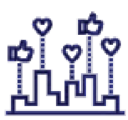
Stakeholder engagement is foundational to a just and equitable energy transition and to the success of the Company's Future Grid Plan. This includes developing trusted partnerships with customers, communities, policymakers, public officials, non-governmental organizations, labor, technology providers, and others who are both impacted by and important contributors to the fair, affordable, and clean energy transition.

3.1 Clean Energy Transition: A Shared Responsibility

The Company is taking steps to identify how to best engage and communicate with stakeholders on an individual and collective basis, including leveraging available resources and forums. Submission of this Plan to the GMAC was an important step in increasing the transparency and inclusiveness of the Company's investment decision making. To further enhance its stakeholder and community engagement, the Company, in conjunction with the other Massachusetts EDCs, is proposing the development of a Community Engagement Stakeholder Advisory Group (CESAG). The primary objective of CESAG is to develop a community engagement framework, centered in equity, that can be applied to major clean infrastructure projects related to the clean energy transition before they are submitted to the Department and/or the Energy Facilities Siting Board (EFSB). Additionally, as it developed this Plan, the Company engaged hundreds of stakeholders through coordinated workshops with the other EDCs, one-on-one meetings, and dialogs with organizations, individuals and customers throughout the Commonwealth and our service area.

National Grid's overarching approach to stakeholder engagement

The Company's approach to stakeholder engagement is rooted in the following:



Building a shared understanding among stakeholders regarding the electric grid, the goals of electric sector modernization plans, and how these investments will help the Commonwealth, communities and customers meet their climate and clean energy goals.

Developing collaboration by engaging stakeholders and establishing conversations to discuss the insights and initiatives required to deliver a smarter, stronger, and cleaner energy future and just transition, in ways that are relevant to them and meet community needs.

Tailoring outreach and stakeholder engagement plans to support local Future Grid Plan projects, elicit and incorporate customer feedback into programs and approaches, and identify community concerns and needs. This includes taking a community-centric, culturally competent, and respectful approach to educate community members about the ongoing and necessary transformation of the electric sector, the upgrades being made to the grid, and the outcomes and tangible benefits they will deliver, and impacts.

The Company engaged a diverse set of stakeholders as it developed the Future Grid Plan

In advance of this filing, extensive stakeholder outreach was conducted to communicate with stakeholders what the Future Grid Plan is, why it is being filed, and how stakeholders can participate in the process. To date, the Company has engaged with more than 80 municipalities, 70 unique businesses, 10 business organizations, representatives of and group representing Environmental

Justice Communities (EJCs), labor organizations, energy assistance providers, organizations representing generators, renewables, Distributed Energy Resource (DER) providers, Electric Vehicle (EV) providers, state officials, housing developers, and others.

Additionally, the Company held several technical stakeholder sessions jointly with Eversource and Unitil in November and December 2023. These technical sessions focused on providing an overview of the ESMPs, including demand forecast methodologies and proposed infrastructure needs, and provided opportunity for stakeholder participation and feedback. Additional details on these sessions are described in Section 3.4. A list of the stakeholders the Company has engaged is included in Appendix.

The Company also leveraged multiple communication channels to educate different customer segments about how they can participate in the Future Grid Plan's stakeholder engagement process. These communication channels included earned and paid media platforms, fact sheets and videos translated into multiple languages, and digital tools such as websites and social content. A sample set of the Company's stakeholder communication materials are illustrated by Exhibit 3.1 below.

Exhibit 3.1: Illustration of Company's Stakeholder Communication Materials

The Company also used existing data and customer research to better understand key priorities and concerns that various customer segments may have regarding the energy transition. This includes engaging with the National Grid Customer Council (Customer Council), which consists of 6,500 residential and 450 business customers that provide insights into customer needs and expectations.

The Company's public engagement team is committed to sharing information and addressing stakeholder concerns from the initial planning project planning phases. The Company seeks to be transparent throughout the lifecycle of projects by providing opportunities for stakeholders to receive timely communication, connect with project teams, and engage in the development process.

Moving forward, the Company remains committed to engaging stakeholders as it develops and executes the Future Grid Plan. The Company will continue to communicate with stakeholders through established channels, use research to better understand customer segments, engage stakeholders directly in facilitated forums and one-on-one settings, and through the newly proposed CESAG.

3.2 Applying an Equity Lens

As the Company worked to develop the Future Grid Plan, it worked closely with the other EDCs to align on common language to define equity. This alignment provides a clear focus and vision across the Commonwealth in how the EDCs value equity.

Equity means engaging all stakeholders – including our customers and communities with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts and justice disparities.

The Company defines equity using three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Initiative.[1] These include:

- **Procedural equity**, which focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation.
- **Distributional equity**, which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition.
- **Structural equity**, which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.

[1] Leading with Equity Initiative

3.3 Engaging our Customers and Clean Energy Partners

Customers: The Company serves a mix of residential, commercial, and industrial customers across the Commonwealth. Our customers have varying levels of interest in and knowledge of energy issues. Exhibit 3.2 below provides an overview of our customer base and Exhibit 3.3 provides additional detail on the demographics of our residential customers. While 88% of customer accounts are residential, nearly 60% of the electric load is comprised of our commercial and industrial customer segments. As the Company makes decisions regarding system planning and investments, it must meet the needs and operational performance expectations of each customer segment, and the unique needs of individual customers within each segment, including the Company's most economically-challenged customers and most energy-intensive and energy-reliant customers.

Exhibit 3.2: The Company's Customer Account Type Breakout

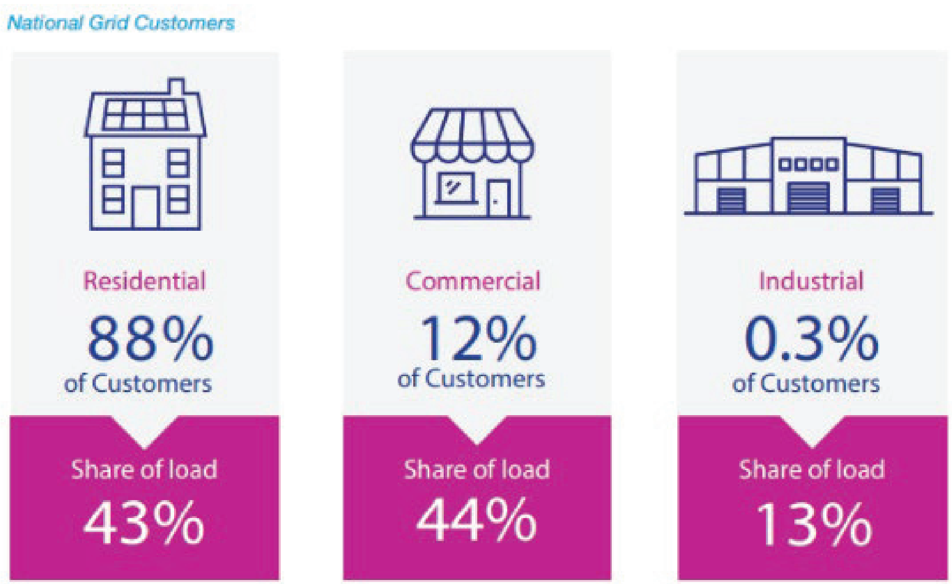
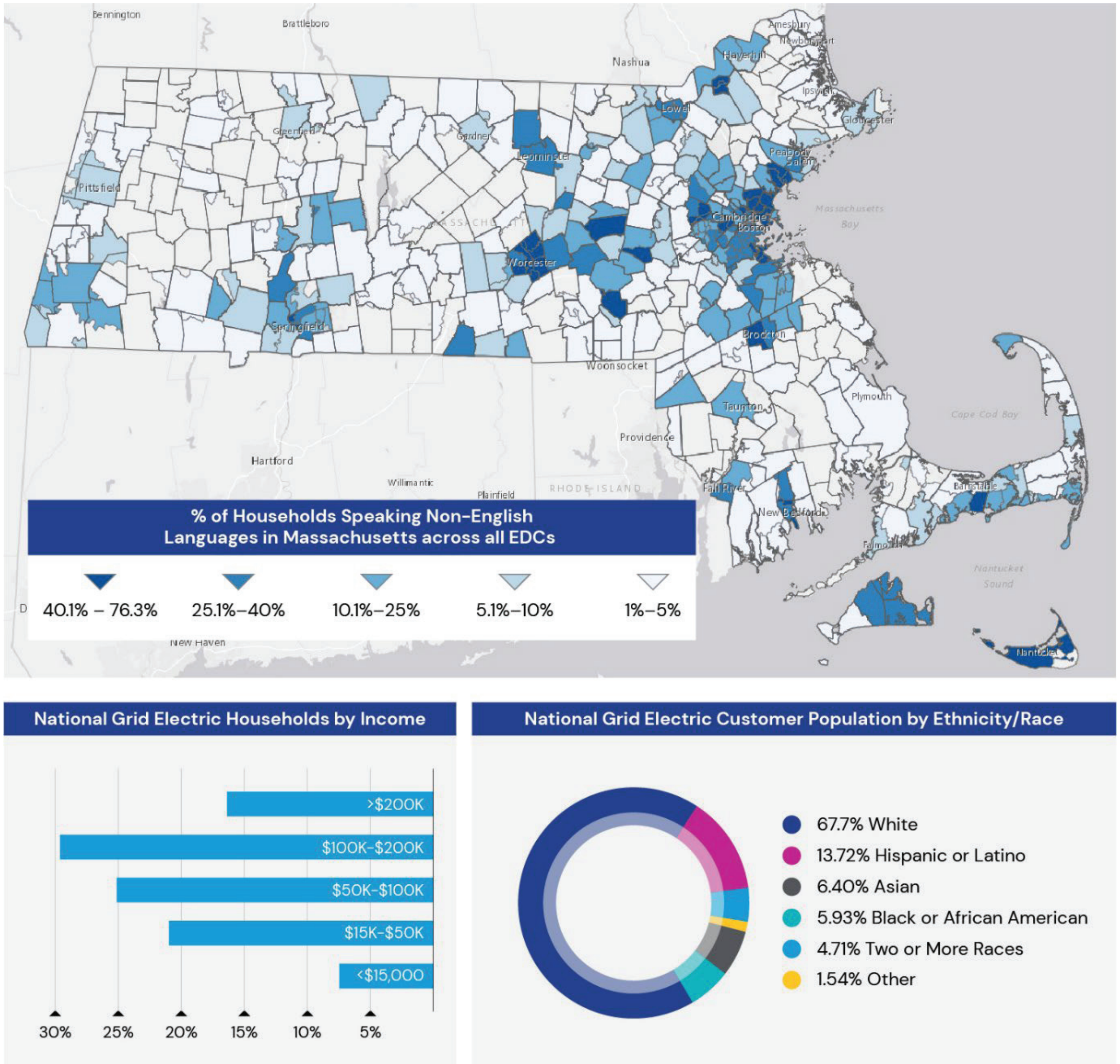


Exhibit 3.3: Illustration of Company's Customer Demographics



The Company's customers are also diverse in how they access and consume information. To reach the broadest possible audience, multiple communication channels are used to reach various customer segments to educate and engage them on the Company's Future Grid Plan. The Company's communications team has created a robust media plan that includes a mixture of paid placements and earned opportunities in a variety of online and traditional channels, including:

- Social Media and Online Platforms (e.g., the National Grid website, LinkedIn, Facebook)
- Newspapers (e.g., *The Boston Globe; CommonWealth Magazine; the Worcester Telegram*)
- Diverse and In-Language Media Outlets (e.g., *El Mundo; La Voz;* the *Bay State Banner)*
- Radio Content and Sponsored Programming
- News Channels (e.g., Telemundo/NBC Boston)

In addition to general communications, the Company is working with business and community organizations and local chambers of commerce to engage with specific customer segments, such as retail, restaurants, hospitals and healthcare, academic institutions, non-profits, and housing and commercial developers. In collaboration with these stakeholders, the Company tailors communications materials to these groups and their members. In addition, the Company holds in-person events to solicit input from customers. Feedback is also collected through focus groups, customer satisfaction surveys, and targeted research to create a holistic perspective on customers' priorities.

The Company also receives valuable input from its Customer Council, which provides feedback on new product innovations, programs, and rate changes. The Company used this Customer Council to solicit feedback on the energy transition and expectations for the future. Below are some examples of responses received:

- "Outage prevention would help everyone in the community significantly – especially during the winter months and extremely hot summer days."
- "All electric sounds great. However, the infrastructure must be there to support this. For example, we have an electric car. We also have a gas-powered car because we cannot rely on access to EV stations."
- "Robust and sustainable are two excellent words for what our power grid should look like. With a reliable power grid, we can all feel safer in our homes and workplaces. Progress (of the sustainable kind) will depend on a secure and available electrical supply."

Clean Energy Partners: The Company works hard to coordinate with those customers that are also key partners in the energy transition such distributed generation developers, real estate developers, builders, labor, etc. These stakeholders provide critical input on program design and operation; they are often a key pathway towards educating our customers who rely on these services.

On December 7, 2023, the EDCs held a technical deep dive discussion at a Technical Standards Review Group (TSRG) meeting. This session was professionally facilitated and designed as an opportunity for DER providers and other clean energy partners to ask questions, voice concerns, and otherwise provide input on the proposed ESMPs. Issues covered in the initial open Q&A included cost allocation, climate change planning, interconnection queue, and scenario planning. This was then followed by a technical presentation offering more detail on DERMS, NWAs, and interconnection development.

State Agency and Stakeholder Outreach: Recognizing the scale and importance of the Commonwealth's clean energy goals and the inaugural nature of the ESMP process, the Company has maintained close communication with pertinent state-level agencies, decision makers, and elected officials. The goal is to ensure that the Company is aligned with state priorities in its investment planning and outreach framework, aiming to minimize any adverse impacts on customers while maximizing their ability to benefit from and participate in the clean energy transition. Meetings have taken place with the following:

- Massachusetts Attorney General's Office (AGO)
- Massachusetts Department of Transportation (MassDOT)
- Executive Office of Economic Development
- Executive Office of Energy and Environmental Affairs (EEA)
- Office of Climate Change and Resilience
- Massachusetts Department of Labor

In addition, the Company engaged with the Office of Environmental Justice and Equity Undersecretary's office, the Department of Energy Resources (DOER) Commissioner's office, and with the chairs of legislative committees responsible for overseeing energy-related issues. These individuals have expressed interest in the ESMP filing and will have active roles in implementing and overseeing the clean energy transition.

Finally the Company actively engaged with and received feedback through the members of the GMAC and public input in these sessions. Topics for these GMAC sessions included distribution planning, load forecasting, review of active EDC dockets, stakeholder engagement, equity, DER integration, and cost allocation.

Stakeholder Meetings and Information Exchange

To date, the Company has held more than 100 meetings specific to the ESMP process, reaching more than 250 different stakeholder groups/organizations. These meetings provided an opportunity to share an overview of the Company's Future Grid Plan, elicit feedback on plan elements and future expectations and needs, in general, and request recommendations on how to effectively engage with stakeholders during this process. The Company facilitated the following meetings specific to the ESMP process:

- **Two GMAC Public Listening Sessions,** held in Fall 2023 to receive stakeholder feedback on the proposed ESMP. Notes from these sessions can be found on the GMAC website here (October 30, 2023) and here (November 1, 2023). Written public comments are documented here.
- **Two stakeholder workshops to review the Company's proposed Future Grid Plan**, held jointly with Eversource and Unitil and facilitated by a third party. These technical sessions were held in Fall 2023 and were focused on summarizing the ESMPs, demand forecasts, infrastructure needs, and stakeholder engagement plans. Content from these sessions can be found here (November 15, 2023) and here (November 28, 2023).
- **Webinars** that provide opportunities for the public and all stakeholders to submit questions and feedback.
- **Sponsored forums**, including those hosted by business organizations, local chambers, and news services.
- **Legislative, agency, and municipal briefings**.
- **Participation in relevant conferences** focused on clean energy and climate change.
- **Technical Standards Review Group (TSRG) Stakeholder Deep-Dive Technical Session,** a GMAC-requested technical discussion held jointly with Eversource and Unitil and facilitated by a third party. This three-hour session was held on December 7, 2023, attracting 100+ registrants including 63 attendees representing diverse stakeholders. The session provided technical detail across the EDCs on key topics of interest within the ESMP, which were solicited directly from the stakeholder groups. For more detail, the ESMP presentations at the session can be found here, and meeting notes can be found here.

Stakeholder Input Tracking

As the Company continues to meet with stakeholders, it tracks each engagement in a spreadsheet and captures feedback. The spreadsheet is maintained by Company team members and is shared with the broader team that worked to develop the Future Grid Plan. As additional stakeholder engagements occur, this tracking tool will be modified to classify areas of interest or concern by each stakeholder so common themes can be clearly identified by individual stakeholder, stakeholder category, and geography. Stakeholders can also directly provide Plan feedback to the Company via an email, future.grid@nationalgrid,com, which is available on the Company's website. Information collected through this portal will be tracked in the tracking document.

As the Company moves towards executing the Future Grid Plan, it will make a concerted effort to actively engage with communities that have been identified for system upgrades in the next 10 years. The Company has a dedicated team focused on community and municipal outreach for larger capital infrastructure projects. This team has an established process for education and engagement that aligns with MEPA requirements. This process will be further enhanced by the Equity and Environmental Justice Policy and Framework as it is put into operation.

National Grid is reviewing its engagement process in general to make it more proactive, robust, and inclusive. National Grid will incorporate stakeholder engagement best practices, including its approach for projects seeking Infrastructure Investment and Jobs Act grants, such as Brayton Point, and the Geothermal Demonstration Program in Lowell. National Grid will draw insights from these engagements to better inform the stakeholder process going forward, with a particular focus on EJCs and how to develop community benefit plans collaboratively.

Key Takeaways from Stakeholder Engagement

The dialogue the Company has held with stakeholders to date has been robust and guided by a presentation to facilitate dialogue. The purpose of the engagement has been to build understanding and begin to identify ways to develop collaboration channels going forward. Key takeaways from stakeholder engagement conducted by the Company to date include:

- **The importance of a deliberate and equitable transition and meaningful engagement.** Stakeholders emphasized the need to start engaging and planning with impacted communities and customers early in the process to ensure that concerns are being captured and addressed, that agency is provided in siting decisions, and that work is coordinated with other stakeholders and to support timing of customer and community needs. Stakeholders noted that early engagement can help identify opportunities for partnership and shared benefits, particularly for communities that currently are or will be impacted by significant energy infrastructure investments. Many energy-intensive/reliant businesses and developers raised concerns about whether the electric network is capable of supporting accelerated electrification and meeting increasing demand in the next decade. Municipal stakeholders indicated interest in leveraging infrastructure investments in the Future Grid Plan to fulfill their own clean energy and economic development goals and ensuring that investments were paced to align with needs. Finally, many labor partners shared concerns about workforce availability and training and the safe and reliable operation of both the gas and electric systems during the transition.

- **The need to maintain an affordable and reliable energy system.** Affordability and reliability are different goals, and each can mean different things to different customer segments. However, both are top of mind for many stakeholders. Stakeholders raised several times the need for EDCs to focus more holistically on EJ concerns (such as energy burden and increasing enrollment in existing affordability programs), as well as the need for alternative rate structures that allow customers to better manage energy use and costs. In addition, engaged stakeholders expressed support for programs that provide value streams for various demand management tools and customer-owned solar and storage.[2] Additionally, most stakeholders emphasized the need to ensure the system is resilient and able to respond quickly to any event. Stakeholders commented that current reliability and storm response systems work well and wanted to ensure they are maintained as the economy becomes more electrified. For businesses for which electricity is a critical input, such as healthcare and biotech, system resilience and redundancy are paramount as the cost of even momentary outages poses financial and operational challenges.

- **The challenges faced by customers and technology providers interconnecting to the Company system in a timely and affordable manner.** Stakeholders emphasized the need to make it easier to do business with the Company. This issue was particularly acute with housing and commercial real-estate developers as well as DER providers. There is a recognition that the Company is working to shorten time frames, secure supply chains, and streamline processes. However, many stakeholders feel that more needs to be done to keep up with the pace of electrification and the clean energy transition, driven by policies such as building code changes and the prohibition on the sale of internal combustion engine vehicles by 2035. DER providers, housing developers, large customers, and economic development-focused organizations want more timely and dynamic information on available grid capacity to host their projects, building off existing hosting capacity maps provided by the Company.

- **The importance of programs that provide financial and technical support to pursue clean energy and energy efficient solutions, such as Mass Save.** Stakeholders raised the need to expand programs like Mass Save and make them more targeted to individual customer segments (e.g. small businesses, commercial real estate, academic institutions, LMI customers, and municipalities). For example, many municipalities are concerned about the costs of the energy transition and ability to participate fully, both for themselves as well as for their constituents. They expressed concerns about the challenges aging housing stock presents to weatherization and EE efforts, such as retrofitting to install electric heat pumps. Multiple municipalities emphasized the importance of the Mass Save program and the need to expand and increase funding for the program. Many municipalities also raised the need for additional support for fleet electrification, including technical support and support identifying and securing available state and federal grants to reduce the costs of the transition.

[2] The Company proposed program and process changes in its recent Massachusetts Electric Company base rate review filing to address this feedback and will be proposing program and process changes in the Mass Save 3-year program cycle review for 2025-2028.

Massachusetts has designated $50 Million to establish a Climate Finance Accelerator (also known as 'Green Bank') to attract private capital and connect consumers to upfront capital needed to switch to clean energy, which helps save money in the long run. In addition, Massachusetts is considering establishing a Building Decarbonization Clearinghouse to provide streamlined offerings, assistance navigating incentive programs, and informational resources for consumers seeking to upgrade and electrify their homes and vehicles to be zero-emitting. The Company will coordinate with both the Massachusetts Green Bank and Decarbonization Clearinghouse to align program offerings and provide additional support to all customers to enable the clean energy transition.

3.4 Community Engagement and Transparency

In addition to the outreach described in the previous Section, the Company is making a concerted effort to connect with the municipalities and EJCs, which have had an underrepresented voice in the utility planning process. The follow section describes how the Company will work to increase engagement with these groups moving forward.

Municipal Outreach

Engaging with local leaders is a critical part of the ESMP process and essential for executing the Company's Future Grid Plan. Local communities want to be a part of the utilities' decision-making process when choosing locations to build infrastructure, the timing of construction and service, and overall design/footprint. They want to understand the 'why' and 'what' and then be involved in the determination of the 'where' and 'how.'

The Company provides electric service to 172 of the 242 municipalities in the Commonwealth that it serves. The infrastructure investment needed to reach clean energy goals will occur at the local level, which requires close coordination with local municipalities on engagement for specific projects. The Company will also need to coordinate with municipalities to obtain permits and rights of way to ensure that our construction schedule does not conflict with the municipalities' own policy priorities or infrastructure schedule. These municipalities are also Company customers. Many have their own climate and clean energy goals, some of which have stated greenhouse gas reduction targets or detailed decarbonization plans. In addition to clean energy policies, local municipalities have economic development goals and housing needs.

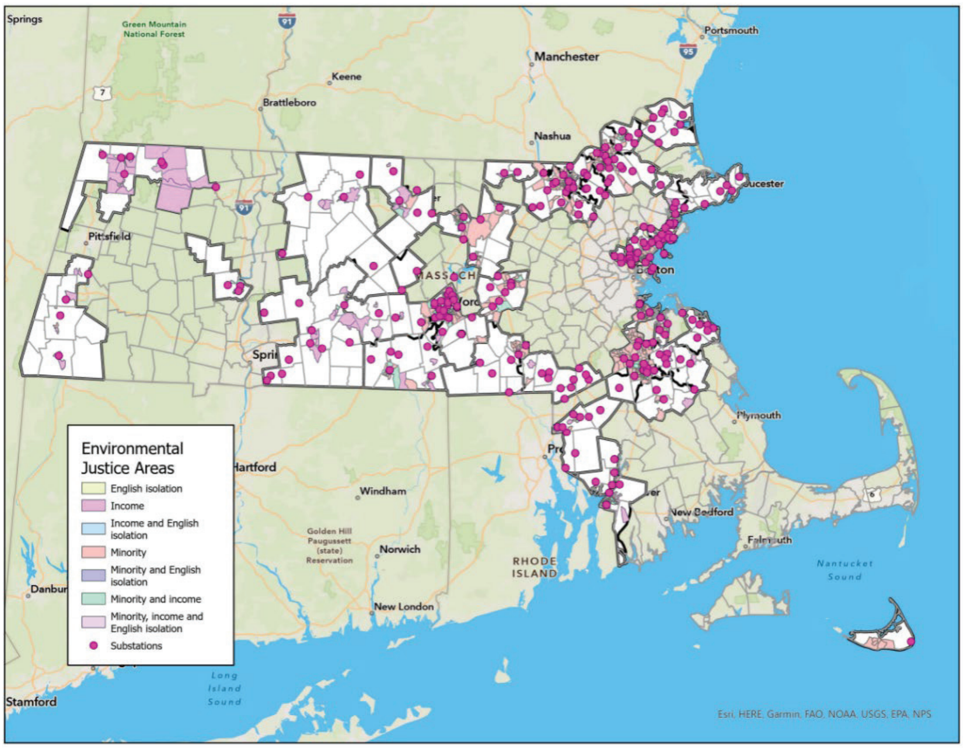
To better understand the interests of each municipality and their constituents, the Company is in direct dialogue with municipal leaders, including mayors and energy managers. The Company also engages with municipalities through organizations such as the Massachusetts Mayors Association and Massachusetts Municipal Association. In advance of this filing, the Company conducted outreach to myriad of municipalities, including those identified as having substantial infrastructure investment needs (e.g., expanded or new substations) proposed in the first 10 years of the Company's Future Grid Plan. A list of the municipalities engaged on the ESMP is provided in the **Appendix, *Equity and Environmental Justice Policy and Stakeholder Engagement Framework, Exhibit 3.***

Going forward, the Company intends to continue and expand its outreach, with an initial focus on those municipalities that include infrastructure projects in the first 10 years. It will conduct this outreach directly, via one-on-one engagements, and convene regional meetings to bring officials together to provide an overview of the regional impacts and benefits of these proposed investments and enable dialogue between officials on regional energy plans, needs and opportunities.

Environmental Justice Community Outreach

The Company serves many gateway cities and communities throughout the Commonwealth, including Brockton, Quincy, Worcester, Lynn, Lowell, Lawrence, Haverhill, and North Adams. These municipalities have large EJCs, as defined by the Commonwealth and identified in census data. The Company recognizes that a significant portion of Company customers live in EJCs, which are disbursed throughout the Company's service area, as shown in Exhibit 3.4 below.

Exhibit 3.4: Environmental Justice Areas



In 2023, the Company participated in a dialogue with a broad group of environmental and social justice stakeholders focused on energy equity and justice. While this engagement was not specific to the Plan or ESMP process, it informed Company efforts to drive equity and address energy burden through current outreach and engagement efforts, elements of this Plan, and other actions the Company proposed as part of its MECO BRC filing.[3]

Participants in this dialogue included representatives from labor organizations, government agencies, direct service and environmental organizations, energy advocates, technology providers, and academic institutions. In addition, the Company met with members of the EJ Table, the current Assistant Secretary for Environmental Justice at EEA, and municipal leaders representing large EJ

[3] D.P.U. 23-150.

constituencies. The Company also participated in and presented at an Advanced Energy Group convening in fall 2023 on equity and public health vis-a-vis grid modernization. The Company has reviewed and considered feedback and recommendations included in the following policy documents: *Executive Office of Energy and Environmental Affairs (December 2022); Clean Energy and Climate Plan for 2050* (CECP); and Group *Convened by AG's Office Releases Recommendations to Improve Public Participation in Energy Proceedings (Office of the Attorney General, May 4, 2023).*

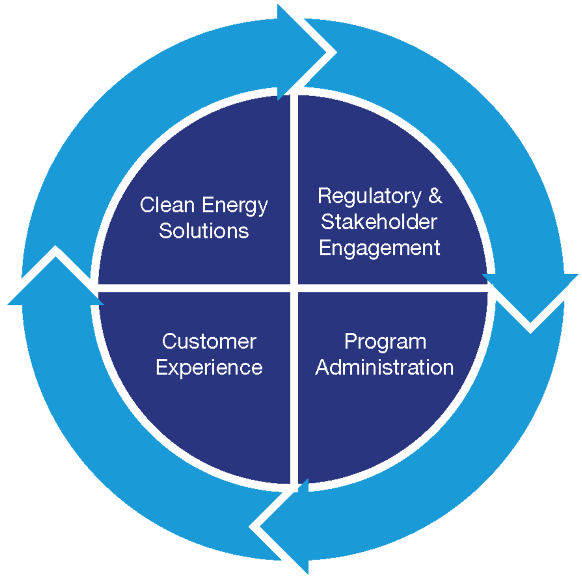
Within EJCs, there are customers that are low- and moderate-income, non-English speaking, new Americans, and/or from minority populations. EJCs are not monolithic and the Company's approach to EJCs, both as a whole and related to individual customer segments, is intentional, tailored, and relevant. The Company recognizes that historically EJCs have borne the highest energy burdens and have been disproportionately impacted by the fossil-based economy.

Low-and Moderate-Income Communities: LMI customers in the Commonwealth face among the highest household energy burdens in the country, given the region's climate and energy prices. Today, an estimated 390,000 Company households have incomes that qualify for some form of energy assistance. A wide range of assistance programs are available, but two key problems are apparent:

- *Low Enrollment*: Enrollment levels in programs vary widely, with the most well-subscribed programs reaching about one-third of eligible customers.
- *Inequitable Assistance*: The largest assistance program – the R-2 low-income rate structure – provides significant assistance but was not designed to equitably reduce energy burden.

In early 2022, the Company engaged E-Source, a research, consulting, and data science firm, to conduct an ethnographic study to develop a deeper understanding of the Company's LMI customers and to create a forward-thinking, multi-faceted customer experience strategy, as illustrated in Exhibit 3.5 Four customer cohorts emerged from the ethnographic study, which were differentiated by customer experience with paying energy bills. From this study, the Company learned that LMI customers are primarily concerned about overall bill affordability, including making EE improvements that may reduce their energy bill. The Company also reached out to AARP as part of its ESMP stakeholder engagement process to gain insights into the unique needs and circumstances of the energy burdened senior population.

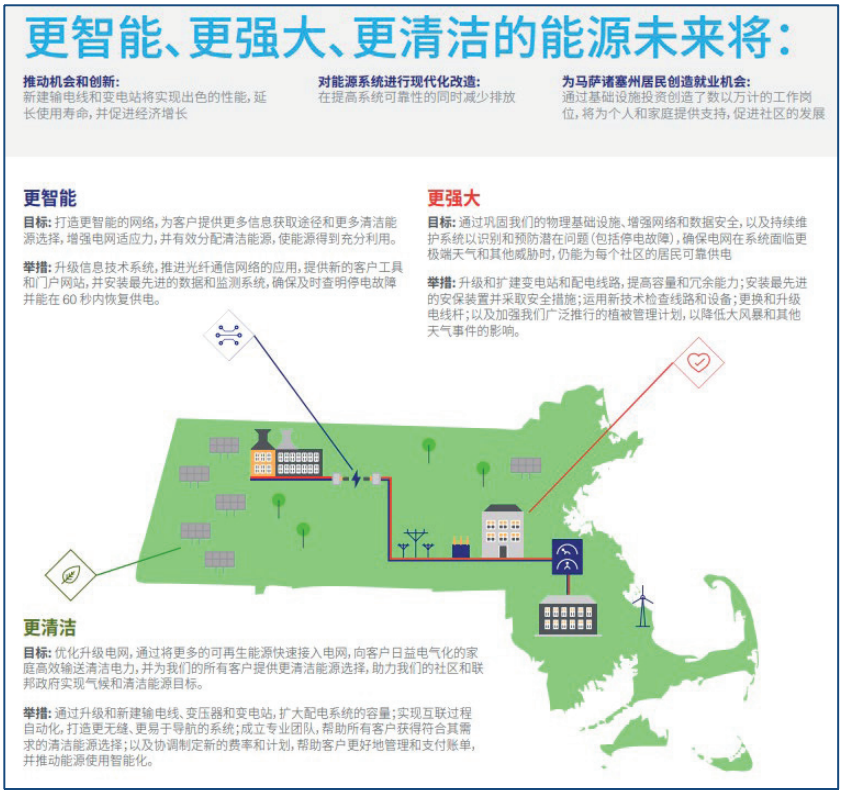
Exhibit 3.5: The Company's Customer Experience Strategy



Broad alignment is needed to further develop existing programs, aiming to increase enrollment and reduce energy burden, particularly for moderate income customers who may not meet current income-eligibility criteria. The Company recently filed the Commonwealth's first-ever equity-based approach to providing discount rates to income-eligible customers to help address these concerns in November 2023 as part of its MECO BRC filing. Customers eligible for a reduced electric rate currently receive a 32% discount, no matter their income. In its place, the Company is proposing a more equitable approach based on a customer's energy burden. This shift would result in a discount of 32% up to 55% for customers who earn 60% of the state median income or less.

The Company will also continue to partner with energy assistance organizations (e.g., Community Action Program (CAP) partners, Community First partners, the AGO, and trusted nonprofits supporting LMI communities such as food banks and family support service organizations) to reach eligible customers, raise awareness of available assistance programs, and elicit community feedback on these plans. Finally, the Company continues to partner with municipalities that have high EJ populations to hold in-person Customer Energy Savings Events to educate LMI communities on available assistance and share information on the Future Grid Plan.

Non-English-Speaking Communities: Roughly 23% of Massachusetts residents speak a language other than English at home. In the Company's service area, the municipalities with the highest representation of non-English speaking communities include Lawrence, Lynn, Revere, Southbridge, Everett, Methuen, Worcester, and Haverhill. Many non-English speakers are new immigrants, and thus have cultural norms and practices that may vary from the prevailing culture in the broader community. Therefore, educational outreach and engagement must be language-friendly and mindful of cultural nuances. The Company will translate all pertinent publications – particularly related to infrastructure project work, affordability, energy conservation, and bill management – into multiple languages. Throughout the outreach process, the Company will collaborate with community members, leaders and trusted third-party partners from these communities to ensure culturally sensitive communication practices are emphasized.



Minority Populations: Approximately one-third of the Commonwealth's residents are minorities, as illustrated in Exhibit 3.3. While some minorities are non-English speakers and/or new immigrants, many come from multi-generational families and have deep roots in their communities but may nonetheless receive information and respond to outreach via a defined subset of trusted voices and media outlets. Company outreach and engagement plans will be intentional in this respect, relying on trusted community partners, faith-based groups, and individuals, as well as targeted outlets, including via social media platforms, advertising, YouTube, or print media to reach specific customer segments.

The Company currently provides a suite of programs and offerings to LMI customers and customers in EJCs that are designed to increase adoption of clean energy technologies and help manage/reduce energy costs. Examples of these offerings and programs are provided in Exhibit 3.6.

Exhibit 3.6: Programs for EJCs and LMI Customers

Technology Type	Offering
EV charging (Phase III program)	The Electric Vehicle Charging Program incentivizes commercial customers to install EV charging by rebating costs for the charging stations and associated infrastructure. Customers locating chargers in or utilizing fleets driving in EJCs are eligible for increased incentive amounts.
	The Residential EV Charging Infrastructure Program offers customers in 1 to 4 unit housing a rebate for wiring upgrades needed to support Level 2 EV charging. Customers in 2 to 4 unit housing within EJCs can receive an increased rebate amount.
	The Turnkey EV Charging Installation program goes beyond the Residential EV Charging Infrastructure Program for Low-Income and EJC customers by covering the purchase and installation of an EV charger at their homes.
	Multi-Unit Dwelling EV Ready Site Plans program covers the cost to provide 20+ unit residential properties with a customized plan to install EV Charging on-site,
Solar/storage	Solar Lease Program: Partnership with Posigen to provide a lease option through National Grid's existing Solar Marketplace
Energy Efficiency	All eligible energy efficiency measures and building electrification upgrades are offered at no cost to low-income customers. All units in a 2-4unit dwelling with 50% or more residents demonstrating income-eligibility receive energy efficiency services, including heating system upgrades, at no-cost.
	Efforts to increase participation in residential energy efficiency programs in environmental justice communities that have a historical participation rate of less than the statewide average.
	100% no cost home weatherization for all rental units
	Income qualified customers are eligible to receive enhanced rebates for eligible heat pumps and fossil fuel heating systems. Customers can also receive up to $10K in financial support to mitigate barriers to weatherization, in addition to no cost weatherization
	EE Community First Partnership: currently working with 34 municipalities and/or community-based organizations, each of which receives up to $60k to launch outreach campaigns designed to reach renters, LMI customers, customers whose primary language is other than English, and small businesses
	Mass Save Language Access Plan
	Affordability Savings Hub Pilot: Email alert program helps low-income customers understand and apply for financial assistance and Energy Efficiency programs. The Savings Hub features are designed to educate customers about the programs they are eligible for, describe the benefits of program participation, and provide direct access to enrollment instructions and the tools needed to begin the enrollment process.
Flexible loads/resiliency	EJC Battery VPP Demo: Provide extra incentives to LMI customers in EJCs that are prone to outages to provide batteries to customers for resiliency, and additionally use them capacity as a VPP for grid services
Other	Equitable Transactional Energy Study
General rate assistance	• Rate R-2 Discount • Arrearage Management Plan • LIHEAP • Budget Billing • Shutoff Protections

National Grid Equity Environmental Justice Policy and Stakeholder Engagement Framework

As the Company prioritizes stakeholder engagement efforts, building relationships with EJCs will help ensure the equitable and successful implementation of the Future Grid Plan. Toward this end, the Company developed a formal Equity and Environmental Justice Policy and Engagement Framework (Framework) which complements the National Grid Indigenous Peoples Initiative[4]. National Grid sought feedback prior to finalizing these Frameworks and will continue to engage with these communities throughout the execution of the Plan.

This Framework is intended to articulate the Company's commitments to centering equity and environmental justice in its Future Grid Plan. The Framework builds on the Company's existing formalized outreach and engagement practices, incorporating input received from EJ stakeholders and recommendations from recent studies published by EEA and the Attorney General's Office (AGO). The Framework was finalized using feedback from stakeholders through the GMAC, the Equity Working Group, and representatives from EJCs.

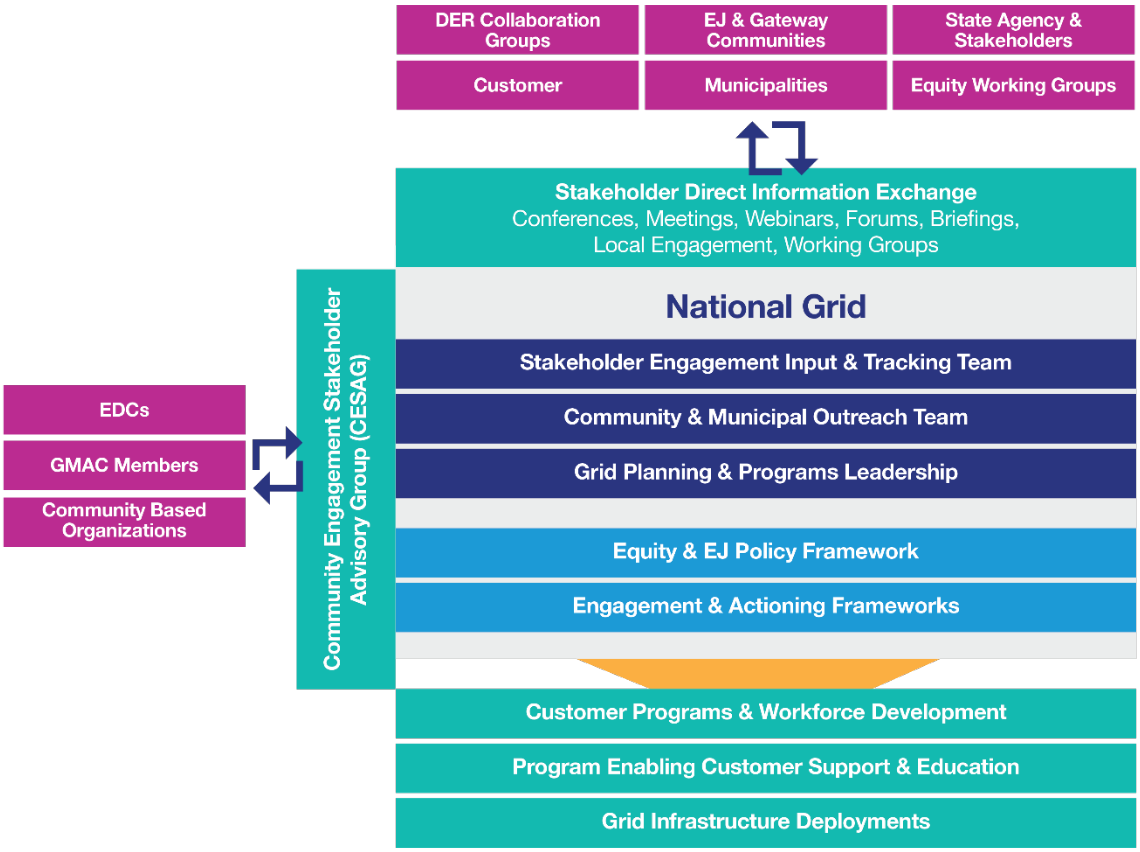
At its core, the Framework affirms the Company is committed to working transparently and collaboratively with stakeholders and communities to support equity and inclusion in the clean energy transition. It recognizes that EJCs may have different infrastructure needs – while many urban EJCs may have sufficient grid capacity and high levels of reliability, other EJCs may currently lack sufficient capacity and may require investments to expand electric infrastructure and enhance resilience.

The Company recognizes that many customers in EJCs face barriers to accessing clean energy solutions, managing their energy bills, and engaging meaningfully in the stakeholder processes that provide for input regarding energy infrastructure and programs in their communities. For example, some EJCs may particularly benefit from transportation electrification, which will have local air quality and health benefits, while others may benefit from economic development that grid investments can support. Therefore, in addition to enabling equitable access to safe and reliable energy service for customers and communities, the Framework also considers socioeconomic benefits through the Company's workforce development program.

Finally, the Company is committed to ensuring it is engaging with customers and communities that traditionally have not been fully represented in the stakeholder engagement process, such as EJ and LMI Communities, municipalities, small businesses, and labor. The stakeholder engagement framework is illustrated as follows:

[4] The Indigenous Peoples Initiative (IPI) includes development of an Indigenous Peoples Statement outlining National Grid's commitment to and respect for Indigenous Peoples. A draft of the Indigenous Peoples Statement was shared with, and revised based on feedback received from, the following Federally Recognized Tribes: Mashpee Wampanoag, Narragansett Indian Tribe, Stockbridge Munsee Band of Mohicans, and the Wampanoag of Gay Head Aquinnah. The IPI also includes hiring an Indigenous Communities Liaison for New England who will establish community engagement projects based on input from the aforementioned Tribes and conduct employee education events focusing on Indigenous history and culture. The Initiative will benefit Indigenous Communities, National Grid's customers, and National Grid's workforce, and is a first step in strengthening relationships and achieving shared environmental priorities.

Exhibit 3.7: Illustration of Company's Stakeholder Engagement Approach



The Company's stakeholder engagement efforts surrounding infrastructure projects are guided by the following:

- **Build understanding.** It is critical to work with communities to build an understanding of the investment options available to community members to achieve clean energy goals.
- **Collaborative, culturally competent and relevant communication.** The Company is committed to developing new avenues for outreach – including traditional media, email alerts, in-bill messages, door hangers, advertisements, and texts. The Company's goal is to reach every stakeholder where they are and in the language in which they are most comfortable communicating.
- **Tailoring outreach and incorporating feedback.** The Company is committed to tailoring outreach to obtain and then incorporating input from stakeholders and customers into the Company's decision-making process. The Company must be flexible enough to modify their approach as new information and feedback is received. It is critical that community members understand this process, have avenues to make their opinions known, and see their input realized in Company policies and projects.
- **Obtaining Equitable Outcomes**. Every community across the Commonwealth will require infrastructure investment to fully benefit from the clean energy transition. The Company is

committed to engaging with affected communities to realize the benefit of Company projects, including health, equity, and economic benefits, and ensure they do not bear a disproportionate burden.

3.5 Continuing Collaborative Engagement and Outreach

National Grid's goal is to be a strong partner, responsible neighbor in the communities it serves, and ensure all stakeholders are afforded effective and equitable opportunities to access, participate in, and benefit from National Grid's proposed projects. This requires National Grid to build and maintain trusted partnerships through meaningful community engagement and, wherever possible, incorporate feedback into our decision-making processes, especially from those who are burdened with existing negative environmental circumstances and justice disparities. Proactively soliciting and tracking feedback on our clean energy infrastructure projects will be paramount in ensuring successful outcomes.

Engaging with stakeholders early and often, through their desired avenue, is key to soliciting feedback before project plans are fully finalized. It is critical for National Grid to receive this feedback so project plans and their associated impacts aren't based solely on National Grid assumptions but on real feedback from our stakeholders. National Grid is committed to meaningfully addressing the input received and demonstrating how that input factored into decision making.

Community Engagement Stakeholder Advisory Group (CESAG)

To further inform EDC engagement efforts around proposed clean energy infrastructure projects from Section 6, the EDCs are developing a **Community Engagement Stakeholder Advisory Group (CESAG).** The CESAG will allow for a structured opportunity for the EDCs to develop a statewide comprehensive stakeholder engagement framework that will:

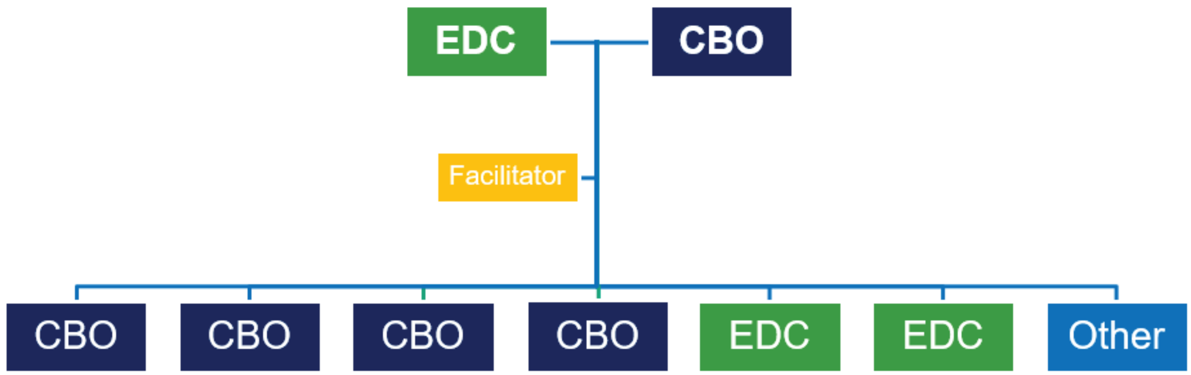
a. Enable increased transparency and stakeholder engagement around: the complex electrical grid, the EDC distribution planning process through the establishment of a repeatable community engagement platform, and an EDC understanding of the historical inequalities and ongoing disparities by listening to the voices of our most vulnerable customers and communities; and

b. Ensure our stakeholders feel respected, understood and heard by finding ways to positively engage with communities, and improve our processes to better understand and respond to the needs of our customers to ensure communities that host large clean energy infrastructure such as substations or associated transmission infrastructure directly benefit from the clean energy enablement infrastructure.

Members and Meeting Frequency:

- Co-chaired by an EDC and a community-based organization (CBO) (voted upon by CESAG members at the first meeting)
- Composed of nine members with representatives from each EDC (3), representatives from different CBOs across the Commonwealth (5), and an environmental or equity advocate (1)
- CESAG charter and by-laws, including term limits will be co-developed by the EDCs and CBOs with input from the equity representative
- CESAG would begin meeting in early 2024, meeting two times per month for 4 months to develop a statewide Community Engagement Framework that can be applied to large clean energy infrastructure projects outlined in Section 6

- Once the frameworks are established, periodic review of these frameworks would be conducted as the EDCs implement them.
- Frequency of future meetings would be determined by the CESAG as applicable
- The EDCs support discussing the potential for reasonable compensation to be paid to community-based organizations that are members of the CESAG through a Department generic proceeding
- Meetings will be professionally facilitated



Community Engagement Framework

With its 2050 CECP, the Commonwealth has established nation-leading and ambitious clean energy targets aimed at transitioning to a decarbonized future. 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 2050 CECP emissions reduction targets. Given the need to execute all ESMP projects, the first mandate of the CESAG would be to develop a *Community Engagement Framework* that can be used by the EDCs as an overall guide to working with all potentially impacted communities and stakeholders prior to clean energy infrastructure projects (from Section 6) going before the Energy Facilities Siting Board.

This framework will be co-developed and informed by the partnerships at the CESAG. At its core, the EDCs are responsible for providing safe and reliable energy. As we each continue to build and enhance our community engagement efforts, it is important the EDCs remain continuously informed by the voices of our communities. We will further this goal by partnering with community-based experts as part of this process. The best path towards successful and clear community engagement is to have a governing framework co-developed by those stakeholders that live in and engage with communities on a daily basis.

The Community Engagement Framework would enable the following:

- Provide clear 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.
- Ensure that historical 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.

- 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.
- Inform the EDCs on best practices for how community input should be solicited and responded to.
- 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 engagement, transparency, and support around our clean energy infrastructure projects. Executing a co-developed framework with host communities in advance of project development will ultimately help to advance 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 will continue to identify ways the EDCs can adjust early outreach and engagement strategies in response to feedback from partners, allies and communities.

Community Benefits Agreements

To ensure that communities that host clean energy infrastructure directly benefit from the infrastructure that is built in their community, a connection between the clean energy infrastructure and specific benefits received for hosting that infrastructure is necessary. Such community benefits agreements (CBA) can take shape as individual EDCs work with a clean energy host community to develop a community benefits agreement specific to that community. No two communities are created equal. Therefore, CBAs will be developed and executed on an individual host community basis. As CBAs are developed with host communities, the EDCs will take feedback and lessons learned from that process back to the CESAG to further ensure all EDCs and CBOs continue to re-think and formulate new methods and approaches to drive benefits of this just transition across the Commonwealth.

Section 4

Current State of the Distribution System

This section provides a comprehensive overview of the state of the Company's electric distribution system today (i.e., the "starting point" upon which our proposed Future Grid Plan is built), including detailed reviews of the current state of the system by subregion.

Key Take-Aways

- The Commonwealth is at an inflection point. The period when the offsetting effects of our nation-leading energy efficiency and solar programs has kept peak load growth flat is coming to an end. This time of stable peak load growth has limited the need to build out expanded system capacity.
- During the last ten years Massachusetts has seen a rapid expansion in distributed solar and increasingly energy storage deployment driven by the success of the Commonwealth policies. The Company's distribution network has become among the most densely DER-connected systems in the country.
- To plan and build the network needed to meet the unprecedented load growth expected, the Company runs a robust process to understand the localized conditions across the diverse parts of the Commonwealth that it serves, including asset conditions, DER adoption trends, demand growth, and customer needs.
- Through effective asset management practices the Company has been able to maximize the value from existing assets, but the Company is now reaching a point where the existing network's capacity has been maximized. The Company must invest to provide more capacity to meet the needs of the clean energy transition.

4.0 Current State of The Distribution System

This Section provides a foundational understanding of the current state of the Company's electric distribution network today, upon which the Company's Future Grid Plan is built. This Section will:

- Provide an overview of how the electric distribution network is designed and works,
- Outline the historical context on how the electric distribution network has evolved over time to meet historical and current customer needs,
- Explain how the electric distribution network is changing to address emerging customer needs, and
- Illustrate the role the distribution utility plays in operating and maintaining network safety and reliability.

This Section will also provide detail on the characteristics of the Company's six planning subregions, setting the context for the investment proposals outlined in Section 6. In addition to discussing the need for capital infrastructure investments, this Section will describe how non-wire alternatives (NWAs) are used on the system and existing technology systems that support the network today. The Company's distribution system is dynamic and data in this Section are accurate as of the date noted.

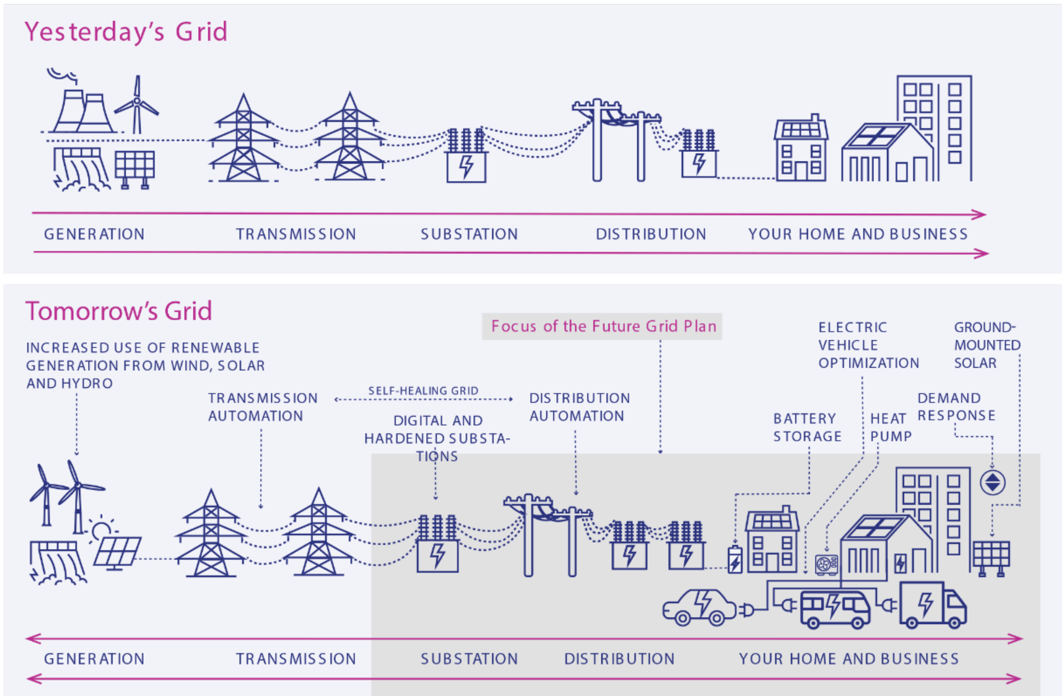
4.1 State of the Distribution System and Challenges to Address

What is the distribution system?

There are three major components of the Company's electrical grid today, as illustrated in Exhibit 4.1:

- **Generation**: Power plants that generate electricity which is sold to the Company,
- **Transmission System**: High-voltage transmission lines that carry electricity over long distances from power plants to local area substations, and
- **Distribution System**: Low-voltage electrical infrastructure that delivers electricity from local substations to homes, businesses, and other facilities.

Exhibit 4.1: Typical Structure of Electrical System



In this section, we will focus on the **distribution system,** which consists of a network of power lines, poles, substations, and other equipment that delivers electricity from the transmission system to end customers. The distribution system differs from the transmission system in that it operates at lower voltages than the high-voltage transmission system, which is responsible for carrying electricity over long distances from power plants or generating stations, and typically carries this electricity shorter distances and to more end points. The distribution system can be thought of as the network of local roads, whereas the transmission system is the interstate highway system.

Substations serve to transform power between the transmission and distribution systems. They are like an "exit ramp", where power steps down (or up) from one voltage to another. Substations play a pivotal role stabilizing the network from abnormal events to improve reliability and safety. They are composed of an assortment of electrical equipment, including the "backbone" of the substation: the power transformer.

- **Transformers** transform electrical energy between high and low voltages. To meet increasing electricity demand, the capacity of the transformers and substations must also increase.
- **Low-voltage circuits** distribute electricity from the substation to homes or businesses. These distribution circuits can run overhead or underground to provide electricity to customers.

The Company's electrical infrastructure has historically been built to facilitate the one-way flow of energy from large power generators (transmission) down to individual customers (distribution). However, with the increase of Distributed Energy Resources (DERs), the role of distribution is shifting from strictly power delivery to a two-way power exchange system. DERs provide energy services connected to the lower-voltage distribution grid and includes technologies such as Energy

Efficiency (EE) Programs, Solar Photovoltaics (PV), Electric Vehicles (EVs), and Electric Heat Pumps (EHPs).

A Brief History of the Company's Distribution System

As the Company plans the future electric distribution system to support the clean energy transition, it is important to understand the history of the system's development within the context of the Company's service territory. Since the origin of the electric grid in the early 1900s, electric service infrastructure has continually evolved.

Initially, electric service in the Commonwealth was concentrated in industrial mill towns and was served by many smaller electric companies – many of which began as gas utilities prior to the invention of the light bulb and the shift from gas to electric lighting. Over time, the grid evolved to transport hydroelectric power from Vermont, New Hampshire, and western parts of the Commonwealth to serve industrial load centers, such as Millbury, Lawrence, and Worcester, more efficiently. At the time, the system typically consisted of 69kv transmission being transformed at local substations to 4kV distribution lines to support service to mills and surrounding communities.

Beginning in the 1910s, electrification expanded rapidly as electric lighting, industrial applications, and residential refrigeration became commonplace. To support this growing demand, local electric companies typically overlayed their 4kV distribution lines with higher voltage 13kV distribution lines. The existing 4kV distribution lines were often left in place due to high costs of replacement, resulting in an "overlayed network" structure that remains in many of these communities.

In the 1950s and 1960s, the electric systems continued to expand rapidly, fueled by significant economic growth. During this timeframe, many municipality-owned and small utilities consolidated into larger utilities. In 1962, nearly 100 small companies consolidated into the Massachusetts Electric Company.[1] The company remained relatively stable in size until 2000, when it merged with the Eastern Utility Association.

Due to this history, the present-day electric distribution system consists of infrastructure with slightly different voltage levels (e.g., 13.2 kV vs 13.8 kV) and a pattern of "overlayed networks". A similar pattern occurred on the transmission system, with 69kV lines of the early century being overlayed by 115kV lines in 1930s and 1940s, followed by 345kV in the 1950s and 1960s.

Today, many of these early mill towns and load centers contain multiple substations and inconsistent voltages as a legacy of the electric system's evolution. Many of these communities contain populations recognized as Low-to-Moderate Income (LMI) or Environmental Justice Communities (EJCs). Looking forward, the Company recognizes the existing network's footprint in some of these communities, including the broader economic and environmental challenges that these communities face. The Company will engage these communities as energy infrastructure projects are developed in their communities to address barriers these customers face with affordability and accessibility of clean energy solutions. Additional details on the Company's engagement with EJCs are described in Section 3 and Section 9.

The Company's Distribution System Today

As the primary electric provider for 172 municipalities and 4,625 square miles across the Commonwealth, the Company serves approximately 1.3 million customer accounts, including approximately 1,138,090 residential households and 126,250 commercial and industrial (C&I) customers.[1] The Company's network delivers nearly 4.9 GW of peak electric demand. The

Company's electric distribution system includes the following major assets:[2]

Exhibit 4.2: Grid Infrastructure by the Numbers

Description	Count
Substations	264
Distribution Line Miles	18,500
Overhead Miles	13,500
Underground Miles	5,000
Poles	720,000
Circuits	1,318
Distribution Service Transformers	183,600

The Company's network primarily consists of 4kV and 15kV class distribution circuits.[3][4] The distribution system also includes a modest amount of higher voltage sub-transmission, including 156 overhead and underground circuits of 23kV and 46 kV supply lines spanning more than 655 miles.

The Company has successfully interconnected approximately 2.3 GW of DERs across the Commonwealth which includes solar, batteries, wind, hydro and others. Interconnection requests continue to increase, with more than 2 GW of applications in queue today. Of these requests, 66% are standalone energy storage facilities and 29% are solar generation – which when implemented, would double the capacity of what is currently connected to the Company's distribution system. The Company's distribution network also currently supports the electrical load from more than 32,000 EVs and 10,000 EHPs, which represents ~1% of total vehicles and less than 1% of customer heating systems. Connections of these end use technologies are expected to increase considerably over the next decade as customers adopt electric transportation and electric heating at a scale described in Section 5, per the Commonwealth's goals.

The Company's network is supported by nation-leading EE and demand response (DR) programs through Mass Save, which saved customers billions of dollars and avoided the release of thousands of tons of greenhouse gases to the atmosphere. These programs have also resulted in a peak demand reduction of 30% or 1.3 GW, keeping load growth relatively flat over the past decade and allowing the Company to avoid or defer some investments in system expansions and upgrades. As discussed below, load growth due to electricity demand is forecast to grow considerably, which will require significant investments in the network to support that demand.

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[1] From the Rivers, the Origins and Growth of the New England Electric System, John T Landry and Jeffrey L Cuikshank, page 172, 1996

[2] Exhibit 4.2 represents a snapshot in time in round numbers, as asset count evolves with infrastructure development.

[3] 15kV class includes voltages such as 13.2kV and 13.8kV.

[4] The Company uses "circuits" and "distribution lines" to mean the same thing and may be found used interchangeably throughout this Plan.

Harnessing the Power of Flexible Demand

For the last 15 years, the Company has kept peak demand relatively flat and avoided investments in network capacity largely through the offsetting effects of the Commonwealth's nation-leading EE programs. From 2013 to 2022 alone, the Company estimates that its EE programs have saved customers over $800m in distribution infrastructure costs. The Company believes that continued EE programs and new approaches to flexible demand will continue to play a critical role in reducing the cost of the energy transition.

What is flexible demand?

Beyond traditional EE, flexible demand includes measures such as DR programs and time-varying rates (TVR) that can incentivize flexible loads like Energy Storage Systems (ESS), controllable thermostats, and EV charging to shift load away from peak to non-peak times of day. The Company today offers several flexible demand programs including its ConnectedSolutions DR programs and its EV off-peak charging rebate program, discussed further in Section 6.

Why is Flexible Demand Important?

The Company plans its network to ensure safe and reliable operation in all hours of the year with particular focus on the peak load. Flexible demand can help offset future peak load growth by smoothing out the use of electricity and thereby reduce, defer and sometimes avoid certain investments in network infrastructure. Flexible demand is more important than ever considering:

1. **Growing demand**. Electricity demand is expected to grow considerably over the next five to 10 years, primarily due to increased adoption of EVs and EHPs, which will require significant investment in the network.
2. **More flexible devices**. More flexible devices are connecting to the network, increasing opportunities to leverage these devices to help manage the grid and to compensate customers for flexibility services.

How is the Company advancing Energy Efficiency and Flexible Demand capabilities over the next 5-year investment period (2025-2029)?

Over the next 5-year investment period, the Company will scale existing initiatives, and propose new programs, policies, and investments to increase the reliance on EE and flexible demand as a resource. A key theme will be scaling existing programs and developing new capabilities to deploy more targeted programs based on specific network and customer needs.

Summary of Proposed Investments and Programs to Expand EE and Flexible Demand over the next Five Years

	Scale Existing (already funded)	In-Flight (authorized)	Net New (via ESMP or related filing)
Customer Programs	• EE • System Peak DR (curtailment, ESS, controllable thermostats, EVs) • Off-peak managed EV charging	• ARI for solar (flexible connections pilot)	• Targeted EE • Targeted DR • TVR • Virtual Power Plant (VPP) • Flexibility Market • Scale flexible connections for EVs and ESS
Enabling Technology		• AMI • ADMS • DERMs (pre-authorized)	• DERMs (expanded features) • Supporting data, security, and communications

As the Company's capabilities mature over time and the Company learns more about customer adoption and behaviors, the Company will modify its forecasts to reflect the expanded role of flexible demand and will integrate flexible load to offset network investments and help address operational needs.

Furthermore, as discussed in section 6, the Company will ensure that customers are able to participate in flexible demand programs and realize cost savings, by conducting broad customer outreach and scaling programs designed for EJC and LMI customers.

The next phase of the distribution system's evolution will be driven by the need to be ready to enable and accommodate significant new load resulting from the electrification of transportation and heating. A key element of enabling an affordable clean energy transition will be encouraging efficient use of the network to avoid the need for excess new system capacity and customer costs. There is an opportunity to reflect on lessons learned, while also utilizing technologies enabled by a Distributed Energy Resource Management System (DERMS) such as active resource integration (ARI) to manage this new load and ensure a more optimal and efficient expansion of the system. Technologies such as AMI, when paired with more dynamic price signals, will also help directly engage customers in managing demand to encourage efficient use of system infrastructure and avoid unnecessary system growth. As these technologies are integrated into the system, the Company recognizes the need for ongoing customer outreach and support, particularly for LMI and EJC customers.

The Company's Role as the Distribution Utility

The Company is responsible for facilitating the planning, construction, operation, maintenance, and restoration of the electric network to fulfill the Company's mission to provide safe and reliable electric power to all customers. The Company must make prudent investments in the distribution networks that it owns and manages – the Company does not own generation facilities except as authorized by statute and the Department of Public Utilities.[5] The Company also provides direct customer services, such as metering, billing, and administering various state-approved EE, EVs, and solar programs. A brief description of a subset of the Company's functions can be found below:

- **Planning**: The Company makes important decisions about how to best serve its customers while maintaining safety, reliability, and affordability. The planning function conducts analyses and makes decisions around replacing existing equipment, investing in new infrastructure, or adopting innovative approaches to maintain the Company's infrastructure and system (e.g., NWAs). Deteriorating equipment due to aging or weathering (i.e., "asset condition") may need to be replaced; broken equipment (i.e., "damage failure") must be repaired; new commercial facilities or solar projects (i.e., "customer work") must be connected to the network; emerging trends in customer outages within specific areas (i.e., "reliability") must be addressed, and expanding and/or upgrading the network to accommodate expected growth in electrical load over time (i.e., "system capacity") must occur.
- **Project delivery**: The Company executes projects (e.g., building a substation) in their investment plans. A typical project delivery process may include engineering, acquiring real estate and permits, evaluating environmental conditions, securing materials, staffing resources, managing construction, and connecting sites with the utility network. The Company delivers dozens of multi-million-dollar projects each year. As an example, a new substation takes, on average, 5-7 years to build from start to finish with 20+ project team members resourced.
- **Operations**: Field operations are responsible for the physical management of the electrical grid. This includes onsite supervision, maintenance of electrical infrastructure (e.g., substations and power lines), integration of infrastructure into the network system, and repairing equipment damaged by storms. Control center operations monitors and manages the network 24/7/365 and has real-time visibility into network conditions to dispatch assets and field operations crews as needed in response to grid conditions. This includes coordinating outage response, implementing switching orders, and scheduling any necessary system reconfigurations or outages to safely facilitate planned maintenance.
- **Metering and billing**: For each end use customer, the Company meters the amount of energy delivered to (or exported by) customers so that they receive bills based on the energy that they consume (and/or produce). This metering function is served for traditional load customers and DERs that export energy onto the grid (e.g., solar).
- **Program administration**: The Company is the program administrator in its service territory for numerous statewide incentive programs, such as those for EE, DR, EHPs, EVs, and Residential Solar. The Company is committed to making participation in the clean energy transformation easy and effortless for customers, and to help them enroll in opportunities to lower their electric bill.

Emerging Challenges for the Company's Distribution System

The role of the distribution utility and the challenges to the distribution network are changing rapidly. The Company must continually adapt its network investment and operations to reflect these shifts.

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[5] Currently the Company owns about 39 MW of solar generation approved under the Green Communities Act of 2008, G.L. c. 164, §1A(f), and the Solar Phase I, II and III programs (D.P.U. 09-38, D.P.U. 14-01 and D.P.U. 16-104, respectively).

Some challenges that the Company faces include:

- **Aging infrastructure**: Aging equipment, such as transformers, switchgear, and power lines, can lead to increased outage risks and decreased system efficiency as their condition worsens. Upgrading and modernizing legacy and decades-old infrastructure is a significant expense due to the cost and complexity involved.
- **Voltage Management and Power Quality**: Maintaining appropriate voltage levels and power quality is crucial for the distribution grid's reliable and efficient operation. High load conditions cause voltage to decrease, and high generation causes voltage to increase. Introducing intermittent generation (e.g., solar, wind) throughout the distribution impacts the voltage profile often in unpredictable ways. Voltage fluctuations, harmonics, and other power quality issues can lead to equipment malfunction, reduced efficiency, and potential damage to consumer devices. This issue is particularly acute for customers with sensitive advanced manufacturing equipment, life sciences and biomedical research laboratories.
- **Resiliency**: Distribution grids are vulnerable to various disruptions, including extreme weather events, natural disasters, and cyberattacks. These threats continue to evolve, and consequences are impactful as electrification accelerates and new devices are added to the system. Increased levels of investment in software, hardware, and infrastructure are needed to guard against system threats.
- **Improving flexibility of network Operations and Management (O&M)**: As DERs become more widespread, the Company will need to manage and operate a more complex network. Variability in solar power generation can create power quality and grid reliability issues. Battery storage can fluctuate significantly as it rapidly shifts from acting as a load (charging the batteries) to acting as a generator (discharging the batteries). Utilities currently lack the tools to directly manage and integrate DER facilities into the grid, which often leaves DER customers with high grid expansion costs to accommodate all operating conditions. The Company is actively investing in technology platforms to better operate and manage the network, such as Advanced Distribution Management System (ADMS) or ARI. These tools are discussed further in Section 6.

These challenges are heightened by the imminent clean energy transformation and changing customer expectations and needs, including:

- **Connecting renewables**: In recent years, the Company has made significant investments in the network to support the connection of thousands of DER projects like solar and energy storage. The Commonwealth has the second largest amount of solar per square mile in the country (0.5 MW/mi[6]) and the Company holds the largest share of solar in the Commonwealth. Continued investment in the Company's networks is necessary to accommodate more renewables. Innovative ways to accelerate the interconnection process will continue to be developed to ensure timely network access.
- **Increased load from electrifying heat and transport**: The significant load growth due to the electrification of transportation and heating will cause the Company's network to shift from summer peaking to winter peaking by the late 2030's. This load growth must be met by the expansion of electric system capacity on both the distribution and transmission networks. If timely investments are not made, the existing infrastructure will become overloaded.

[6] From Electric Power Monthly - U.S. Energy Information Administration (EIA) and US Census Bureau, sourced December 2023. Dividing statewide Estimated Total Solar values (EIA) by statewide land area (US Census) yields the results of MA placing second in the nation (behind RI) with 0.50 MW solar/sq. mi.

This can result in:

1. Asset damage and / or premature aging. Equipment is assigned ratings that specify how much load it can carry without accelerating loss of life, incurring damage, and/or creating unsafe operating conditions. Exceeding these ratings by "overloading" equipment, even for short periods of time, can result in premature asset failures. Load relief projects, like those in this plan, are designed to add new or upgrade existing equipment in order to create the system capacity required to meet projected demand without incurring overloads.
2. Inability to manage contingencies. If multiple assets in a given area are heavily loaded (even within their ratings), the failure of one asset can result in significant outages for customers because the remaining operable equipment in the area does not have enough "contingency" capacity to pick up the load from the out-of-service equipment.

   There are standards and procedures to abate these technical issues, but as more load comes onto the system, more infrastructure will be required. To meet the increased loading, areas of the network where lower voltages (e.g., 4.16 kV) were historically used may need to be converted to higher voltages (e.g., 13.2kV or 13.8 kV). Similarly, substations will need to be upgraded with additional transformer capacity to accommodate future load growth. As the needs and interests of customers change, the Company will need to continue adapt the design and capacity of the electric network.

- **Accelerating timely adoption of customer clean energy technologies and delivering customer-driven programs**: In addition to building out network capacity to support the connection of renewables and adoption of EVs and electric heating, the Company has increased emphasis on administering programs that help customers adopt clean energy technologies. To deliver on the Commonwealth clean energy goals, the Company will need to continue to implement and accelerate incentive programs and information campaigns related to EE, EHPs, EVs, and DR.

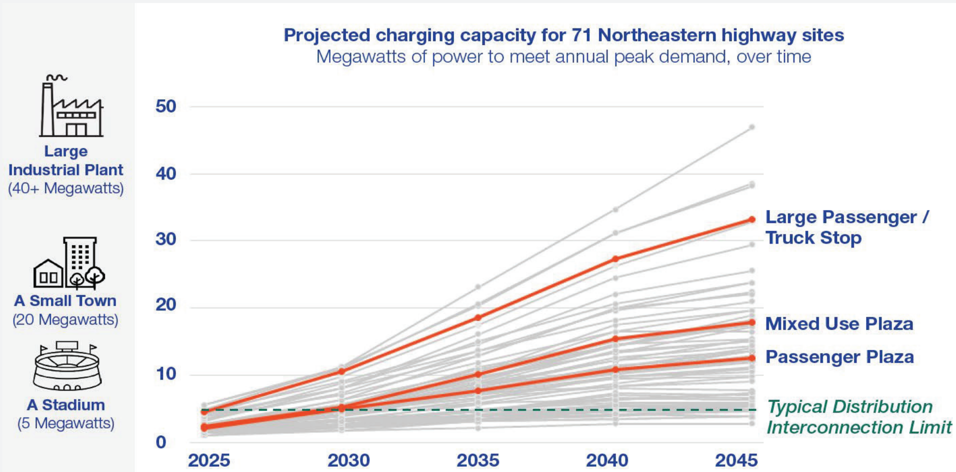
EV Charging along highways and at fleet depots is critical to meet the Commonwealth's transportation electrification goals. The Company already offers make-ready funding, managed charging offerings, and other programs for EV customers to encourage adoption of EVs (See Section 6). Also, the Company has conducted industry leading studies and engaged stakeholders to address the unique challenges of building distribution (and transmission) infrastructure for EV charging. Proactive planning is critical to meet customers' needs as they arise rather than in a reactionary fashion.

Electric Vehicle Charging – Along Highways

Highway service plazas, truck stops, and similar sites adjacent to highways will be used by fleets of light-duty vehicles (LDVs) and medium- and heavy-duty vehicles (MHDEVs). Highway charging sites present specific challenges because of their unique characteristics.

a. **En-route charging must be fast and convenient.** Highway charging will need to be faster than other public chargers and managed charging opportunities will be limited because unlike home or depot charging, charging time will impact the driver. The National Electric Vehicle Infrastructure (NEVI) standards require ≥150 kW per port, and future charging for trucks could be >1 MW per port.

b. **Highway charging creates large "net new" electrical loads.** (See chart below). The power required for fast charging at these sites could be comparable to the electrical load from a new sports stadium or a small town, and will likely require new grid infrastructure.



Source: *National Grid Electric Highways Study*

c. **Building grid infrastructure takes longer than building EV infrastructure.** Currently, the Company must wait until the EV charging customer requests service before designing and deploying a solution. The grid infrastructure for these sites can take years to design, permit, construct, and energize which is significantly longer than deploying the chargers themselves. The Company must forecast the need and design solutions before having the certainty of a customer load letter to ensure the network is ready when the demand materializes.

Section 6 includes three proposed substations to support future EV highway charging loads at service plazas in Charlton, Westborough, and Bridgewater. All substations are projected to be in-service by 2034. While these three stations have been prioritized based on the results of the Electric Highways Study, the Company acknowledges that other locations will also likely require more capacity in the future.

Electric Vehicle Charging – At Fleet Depots

The Commonwealth's ambitious transportation electrification policies mean that fleet owners will transition their fleets to EVs. Providing power to fleet depots is challenging for several reasons.

a. **The number and energy requirements of fleet vehicles create large "net new" electrical spot loads.** As with highway sites, fleets, especially MHDVs, will have significant power needs and will likely require upgrades to grid infrastructure. For example, below is data from the Electric Power Research Institute (EPRI) that estimates charging needs in one "cluster" of fleets. These depots would require at least 14 MW of new load when they fully electrify, while a typical distribution line can accommodate around 10 MW.

Area is approx. 1 square mile.
All depots are served by the same distribution feeder.

Source: EPRI eRoadMAP (https://eroadmap.epri.com/)
Full electrification scenario. Retrieved December 2023.

b. **Building grid infrastructure takes longer than building EV infrastructure.** As with highways, the grid infrastructure for fleet sites can take years longer than customer plans. The Electric Vehicle Infrastructure Coordinating Council (EVICC) Initial Assessment (August 2023) highlights the challenges fleet depots are *already* facing with grid capacity.

c. **Forecasting the exact location, timing, magnitude, and load curve for EV spot loads is a new challenge.** Very few fleets have already developed their electrification plans, so most cannot make specific capacity requests or even signal long-term intent. This leads to inherent uncertainty in forecasting what customers will do before they themselves have formulated plans. Nevertheless, policy is clear and EV economics and performance are consistently improving, indicating that these vehicles will electrify in the future.

While the Company has a system-level forecast for EV fleets, it does not yet have EV spot loads explicitly identified. To serve the need in a timely fashion, the Company will need to design solutions with less certainty than utilities have traditionally had. The Company is exploring new methodologies to identify EV spot loads in demand forecasting to help prioritize network capacity increases. The Company will need a framework to identify depot locations, estimate charging loads and load curves, design solutions, approve development, and begin construction, all in advance of when needs will materialize.

Current State NWA Considerations

Where a system need has been identified, the Company performs an initial screening for the suitability of an NWA to meet that need. The screening criteria consider the project type (load relief or reliability), timeline (start of construction at least 18 months in the future) and cost of wires solution (at least $500k). An NWA is considered as an option to defer the wires solution for a specific period of time for those projects which satisfy the screening criteria.

Siting and Permitting – An Overview

The massive construction program necessary to meet projected demand on the electric grid will place extreme stress on permitting processes that are already stretched to the point where permitting has become a source of unnecessary delay without any corresponding benefit either to the environment, host communities, or the Commonwealth.

“Business as Usual” Permitting for Energy Infrastructure

Massachusetts has a multi-layered, often redundant, process for permitting energy infrastructure that includes, as necessary:

- Review of environmental impacts coordinated by the Massachusetts Environmental Policy Act (MEPA) Office and including review and comment by state and local permitting agencies
- Wetlands and other natural resource permits from various state environmental agencies
- Local wetlands and land use permits
- For larger projects, siting review by the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Board (EFSB), or both

Exhibit 4.3 illustrates the wide range of stakeholders that can be involved in the permitting process today and the activities that they are involved in.

Exhibit 4.3: Permitting Activities and Involved Stakeholders

	US Fish and Wildlife (ESA)	US EPA (NPDES)	Army Corps of Engineers s. 404	Army Corps of Engineers s. 10	Army Corps of Engineers s. 106	MEPA	EFSB/DPU	DEP Wetlands (Water Quality Cert.)	MHC	NHESP	DCR	DOT	DEP Air Quality	DEP Waterways (c. 91)	Conservation Commissions	Boards of Selectmen/City Councils	Tree Wardens	Zoning Boards	Planning Boards
	Federal					State									Local				
Agency and Community Outreach/Pre-App Consults	√		√	√	√	√	√	√		√	√	√	√	√	√	√	√	√	√
Air Quality						√	√						√						
Alternatives Analysis						√	√	√											
Areas of Critical Environmental Concern			√	√		√		√											
Coastal Zone Management		√	√	√		√								√					
Climate Change Adaptation and Resiliency						√	√							√		√			√
Consistency with Local Planning						√	√	√						√	√			√	√
Construction Access		√	√	√	√	√	√	√	√	√	√	√							√
Construction Schedule & Sequence		√	√	√	√	√	√	√	√	√	√	√		√	√	√		√	√
Construction Work Hours							√									√		√	√
Environmental Justice Populations						√	√						√			√			
Established Best Management Practices	√	√	√	√	√			√	√	√	√	√	√	√	√			√	
Existing Conditions	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Greenhouse Gas Analysis						√													
Historic and Archeological Resources			√	√	√	√	√		√		√			√					
Minimization of Project Impacts	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Mitigation Measures	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Noise	√				√	√	√		√							√		√	√
Project Purpose and Need	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√		√	√
Public Hearing/Comment Period	√		√	√		√	√	√					√	√	√	√	√	√	√
Public Lands and Article 97			√	√		√	√				√					√		√	√
Public Notice	√		√	√		√	√	√					√	√	√	√	√	√	√
Public Shade Trees						√	√									√	√		√
Regulatory Compliance	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√
Safety and Public Health Considerations						√	√					√				√		√	√
Solid and Hazardous Waste						√	√	√						√					√
Stormwater		√	√			√		√			√			√	√				√
Traffic and Transportation						√	√					√				√		√	√
Visual Impact Assessment					√	√	√		√					√		√		√	
Watercourse Waterways and Tidelands			√	√		√	√	√						√	√				
Wetland Delineation Methodology			√			√	√	√							√				
Wetland Impacts & Mitigation			√			√	√	√							√				
Wildlife Habitat Assessment and Mitigation	√					√	√	√		√					√				

Each permitting process creates an opportunity for appeal, which can significantly delay project construction and increase costs. Although the Company recognizes the importance of having widespread, comprehensive, and equitable stakeholder engagement (as discussed in Section 3), there is often significant subject matter overlap between these various review processes. Further, the sequence of permitting can result in permitting timelines of three to four years from the date of filing for certain energy infrastructure projects; longer if an EFSB proceeding is required; and even longer if permit approvals are appealed.

- The EFSB process, in particular, is heavily backlogged, and despite a one-year statutory deadline, its review and approval for transmission projects is averaging more than 24 months. This is due to a variety of factors that include staffing and resource constraints, an increasing volume of cases, and an uptick in judicial appeals, which require staff to take more time reviewing projects and writing orders.
- A business-as-usual approach to environmental permitting has, and will continue to, delay necessary projects. For example, the MEPA office recently refused the New England Electric Power Company's (NEP) request for a Single Environmental Impact Report (EIR) on two different projects, citing the need for additional alternatives analysis, even though the projects involve rebuilding existing transmission lines within the same right of way.
- Wetland impacts are subject to multiple and overlapping reviews and permitting regimes at the federal, state, and local levels, even though the impacts are primarily temporary due to the use of construction mats that actually protect the wetlands. Wetland impacts and required mitigation for electric utility projects are well known by the regulatory community and can be efficiently addressed through best management practices and standard permit conditions.
- The local permitting process has historically followed after state approvals, which has led to redundant reviews of environmental impacts and inconsistent permit requirements. Further, local agency review sometimes expands to incorporate topics that are outside an agency's jurisdiction or unrelated to the project scope. Again, this can introduce significant delays to needed projects.
- Public participation is at the core of this Plan, as detailed in Section 3. However, the current redundant and sequential processes create barriers to public participation since meaningful participation demands a significant investment of time, money, and effort, including potentially needing to hire expert consultants and attorneys to address highly technical issues and manage multiple permitting timelines and procedures.

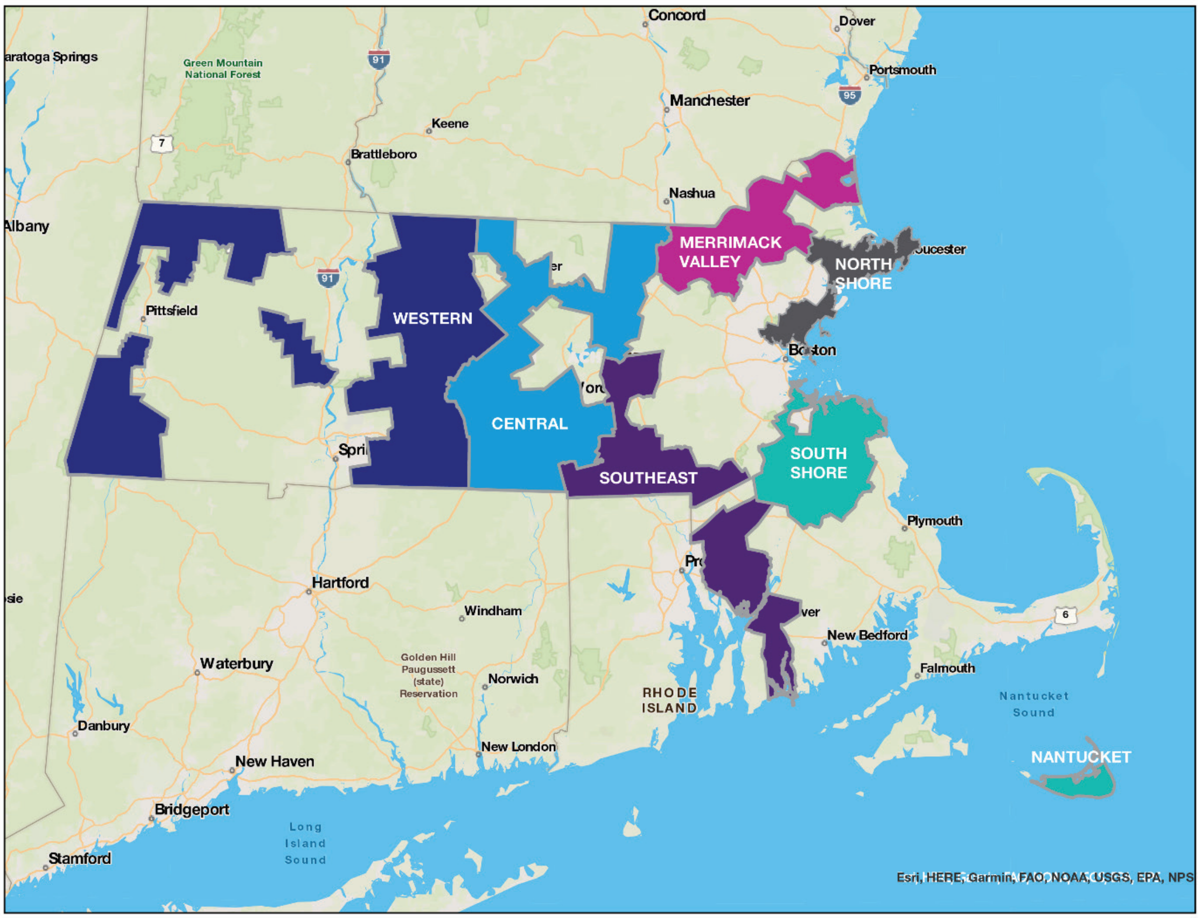
The Company commends the Healey administration's interest in addressing the problems in the energy infrastructure review process and looks forward to working with the newly-formed Commission on Energy Infrastructure Siting and Permitting (CEISP) on siting and permitting reform while maintaining the Commonwealth's high standards for environmental protection and improving community engagement. The Company believes that a consolidated permitting process that relies on a commitment to best practices in both environmental protection and community engagement is the only way that utilities and developers will be able to build the infrastructure necessary to achieve the Commonwealth's Net Zero Goals.

4.2 Planning Sub-Regions

The Company's territory spans the Commonwealth, serving a diverse range of geographies including rural communities in the mountainous western part of the Commonwealth, densely populated urban communities in Worcester and Brockton, suburban communities across the Merrimack Valley, and coastal communities along the North and South Shore. Each of these territories have unique physical, economic, demographic and historical characteristics that impact each location's electrical network design and shape the challenges ahead associated with readying that section of the network for the clean energy transition.

For purposes of this Future Grid Plan, the Company has organized the Commonwealth territory into **six operating sub-regions**: Western, Central, Southeast, South Shore (including Nantucket Electric), Merrimack Valley, and North Shore. These regions are summarized in Exhibit 4.4 below.

Exhibit 4.4: National Grid's Six Major Service Sub-Regions



The sub-region groupings are based on both geographic proximity and electrical system characteristics, including distribution design elements such as operating voltages and substations (e.g., two feeders connected to the same substation would be in the same sub-region). The Company has on-the-ground support in each sub-region, including office locations, line crews, metering personnel, customer and community managers, and distribution system engineers.

For distribution system planning and engineering, the Company further divides its distribution system into 46 study areas, which are defined based on electrical interdependencies. Each of the sub-regions contains several study areas, which are summarized in Exhibit 4.5 next page:

Exhibit 4.5: Distribution Study Areas

Sub-regions and Distribution Study Areas					
Central	**Merrimack Valley**	**North Shore**	**Southeast**	**South Shore**	**Western**
Ayer Clinton	Amesbury Newburyport	Beverly	Attleboro	Bridgewater	Adams/Deerfield
Gardner Winchendon	Billerica	Cape Ann	Fall River	Brockton	Barre-Athol
Leominster	Chelmsford Westford	Everett Malden Medford	Hopedale East	Brockton NW / Randolph	Monson-Palmer-Longmeadow
Millbury-Grafton	Dracut	Lynn	Hopedale West	Hanover	Northampton-S Berkshire
Pepperell Dunstable	Haverhill	Melrose Saugus	Marlboro	Nantucket	
Spencer-Rutland	Lawrence	Revere Winthrop	Somerset	Quincy	
Webster Southbridge Charlton	Lowell	Salem Swampscott		Scituate	
Worcester North	Methuen	Topsfield		Weymouth Holbrook	
Worcester South	North Andover				
	North Lowell				
	Tewksbury				

Exhibit 4.6 summarizes key characteristics of each sub-region, including the amount of DER capacity currently connected and in the interconnection queue. Please note the following definitions:

- **Connected DER**: These DER values represent total nameplate capacity (i.e., maximum rated potential of total DER), rather than firm power generation capabilities due to the intermittent nature of DER technologies. The majority of DER projects in service today are distributed solar generation projects. which do not provide a constant, reliable energy source comparable to the utility power source.

- **Pending DER**: The amount of DER capacity in the interconnection queue, which is dynamic as projects enter and exit the queue. Based on historical queue progression, only about 60% of the pending DER projects progress through to interconnection into the system.

- **Peak Load Density**: The peak load per square mile in the area. On a subregion basis, as shown in Exhibit 4.6, this figure provides insight into how much load is consumed in the area and how much energy infrastructure is required given the geographical constraints.

The majority of DER projects built-in-service and in queue today are distributed solar generation and/or energy storage projects. The solar projects can be categorized in one of three buckets: small residential projects (<25kW), medium sized solar projects (<=1MW), and large/standalone solar projects (>1MW). The historical average connection time to get these types of projects interconnected are <5 months, 12-24 months, and 18 months – 3+ years, respectively. Although with significantly decreased headroom in the system and a continually growing interconnection queue, this cycle time has already been increasing in 2023. All projects over 1MW are subject to ISO-NE requirements around notification and potential transmission impact study, and high volumes of applications concentrated in discrete electrical and geographical areas has led to the initiation of group studies in over 60% of the Company's study areas.

The group study process allows the Company to progress a large volume of applications in parallel in these areas, more efficiently progressing the interconnection queue; however, applications in these areas may face longer cycle times as a result. Any projects on a feeder that have ongoing group studies will need even further analysis to understand interconnection implications. The projects that do not end up getting built are limited by a variety of factors, including project financials, siting and permitting, or offtake roadblocks. The Company does not forecast specific large load or large DER connections and does not proactively invest in the network to connect these DERs since they only invest when the DER signs an Interconnection Service Agreement (ISA). What is included in the forecast, discussed in Section 5, is the expected introduction of DER as part of the overall planning process.

Exhibit 4.6: Key Characteristics of Each Sub-Region

	Central	Merrimack Valley	North Shore	Southeast	South Shore	Western
Customers	241,061	263,871	255,067	231,799	239,140	121,606
Feeders	247	297	319	178	187	90
Substations	46	58	49	43	39	29
DER Penetration	High	Medium	Low	High	Medium	High
Connected DER (MW)	631.5	266.6	152.2	425.6	218.6	521.2
Pending DER (MW)	542.6	256.2	77.5	440.8	255.4	431.2
Peak Load 2023 (MW)	943	1,212	1,107	1,029	938	418
Peak Load Density 2023 (MW per sq mile)	1.08	3.14	6.36	1.69	2.32	0.28
Anticipated Load Growth (5 years)	10.2%	6.9%	6.6%	6.7%	6.5%	12.7%
Median Substation Headroom (MW)	19	19	11	13	8	10

The sub-regions within the Company's territory vary from being predominantly rural, to suburban, to urban. The current state of DER proliferation differs, often depending on the availability of open space or the robustness of the existing distribution infrastructure. Looking ahead, these regions also vary in terms of expected load growth. Urban areas are often developed with highly integrated networks to better serve densely populated areas. On the other hand, rural areas tend to have predominantly radial networks, consisting of long distribution lines originating directly from the few substations that serve customers, which are geographically more spread out in these sparsely populated areas. These radial networks are inherently less reliable than highly integrated networks by design but require less infrastructure to develop and maintain.

Sub-region Summaries

- **Central Region**: This region is predominantly suburban, with regional urban centers that are among the largest in the Company's territory. DER penetration in this region is higher than other sub-regions due to the large amount of open space and comparatively robust grid infrastructure in this region. Load is anticipated to grow by 10.2% in the next 5 years.

- **Merrimack Valley:** This region is predominantly suburban, with a few urban centers. The level of DER penetration is average due to limited open space and comparatively robust distribution infrastructure. Load is anticipated to grow by 6.9% in the next 5 years.
- **North Shore**: This region is predominantly urban with metropolitan core communities near Boston. This region has low levels of DER penetration due to the lack of open space coupled with limited capacity on the network. Load is anticipated to grow by 6.6% in the next 5 years**.**
- **Southeast**: This region is predominantly suburban with a few urban centers. There is a high level of DER penetration due to the large amount of open space and comparatively robust distribution infrastructure. Load is anticipated to grow by 6.7% in the next 5 years.
- **South Shore**: This region is predominantly suburban with a few urban centers. It has a moderate level of DER penetration due to somewhat limited open space and limited distribution capacity. Load is anticipated to grow by 6.5% in the next 5 years.
- **Western**: This region is overwhelmingly rural, with regional urban centers. This region has high DER penetration due to the large amount of open space, despite the network being constrained in all areas. Load is anticipated to grow by 12.7% in the next 5 years.

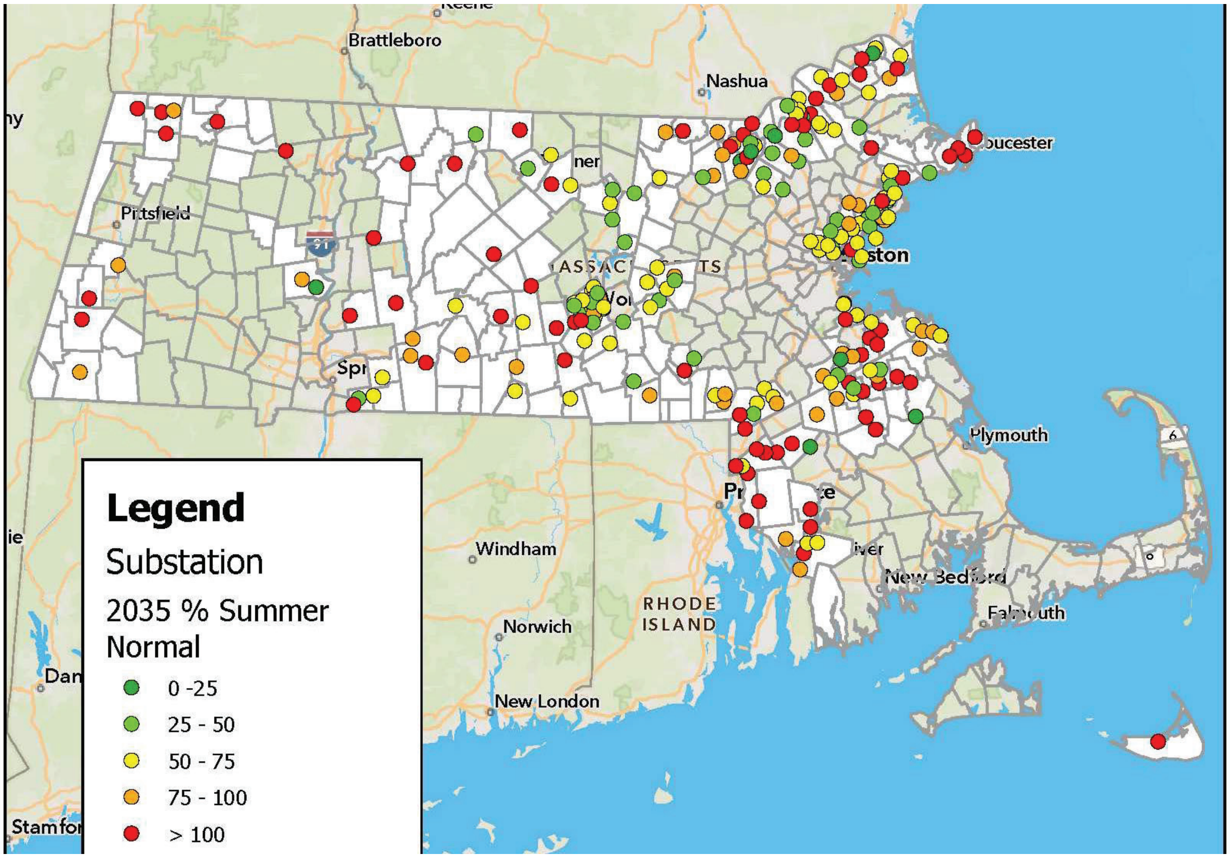
The sub-regions outlined in Exhibit 4.7 contain substation transformers that are currently loaded in excess of their normal ratings. In the short term, in order to preserve system reliability, these overloads can be safely managed through operational measures or planned investments outside of the ESMP. However, the equipment today will not be able to accommodate additional load growth. Per Exhibit 4.7, all regions are expected to see additional load growth that will cause additional transformers to exceed capacity in the next 5 to 10 years. The Company must invest in additional system capacity to support the forecasted load growth due to electrification.

Exhibit 4.7: 5-Year and 10-Year Capacity Deficiencies Absent New Investment

Number of Transformers > 100% Normal Rating						
	Central	Merrimack Valley	North Shore	Southeast	South Shore	Western
2023 Forecast	0	3	0	1	0	0
5-year Forecast	5	8	3	4	3	4
10-year Forecast	12	19	13	19	20	16

Exhibit 4.7 maps the 10-year forecasted transformer data from Exhibit 4.8 to approximate substation load as a percentage of capacity in the Company's service territory, providing a visual for these forecasted overloads.

Exhibit 4.8: Substation Load As a Percentage of Capacity Across The Company's System in 2035, Assuming No Capacity Expansion[7]



In Section 4.3 through Section 4.8, each of the six sub-regions will be reviewed in detail, discussing the geographic, economic, and demographic characteristics of each sub-region, as well as the current state of the electric infrastructure system. The Company's customers' energy needs, economic circumstances, and demographics within each region vary greatly, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the Commonwealth achieve its goals.

4.3 Central Sub-Region

Context of the region

The Central sub-region is predominantly suburban, with regional urban centers in Gardner, Leominster, Clinton, Southbridge, Webster, and Worcester. With a population of slightly more than 200,000, Worcester is the largest municipality the Company's electric business serves in the Commonwealth. The Central sub-region includes the largest municipalities that the Company serves, which are served by a highly integrated network. The Central sub-region also serves a substantial number of rural areas, which have a more radial network.

[7] Substations without summer normal ratings data were omitted from this map.

Exhibit 4.9: Central Sub-Region Network by the Numbers

Description	Value	Unit
Number of Substations	46	Count
Number of Feeders	247	Count
Total Length of Feeders	3,750	Miles
Total Peak Load Served	943	MW
Sub-region Area	875	Square Miles
Benefits of EE	1,216,250	MWh
Heat Pump Adoption	4,184	Count
Charging Ports Installed	291	Count
5-Year Residential Population Growth Projections	2%	Percent
5-Year Forecasted Load Growth	10.2%	Percent
Existing Connected Rooftop DER (< 25kW)	100	MW

The Central sub-region has high levels of DER penetration relative to all other sub-regions due to the large amount of open space coupled with a more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the large population center of Worcester and growing suburban areas, the Company anticipates load to grow by approximately 10.2% in the Central sub-region in the next 5 years. Below are some key characteristics of the Central sub-region which will drive future investment needs.

Exhibit 4.10: Central Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are eighty circuits that operate at 4.16 kV which primarily supply downtown Worcester and are supplied from substations that step down the voltage of 13 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the Commonwealth. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
A 1902 Worcester Bylaw prohibited overhead wires within a 2-mile radius of Worcester City Hall. The Company's solution to this was to install overhead facilities in customers' "backyards," with underground cable and switches in the public way.	Feeders will need to be rerouted out of customers' backyards. The *Underground Bylaw* means the Company must pursue underground solutions for any infrastructure development in this area.

4.3.1 Maps

The Central sub-region consists of 33 municipalities and is comprised of the study areas below.

Exhibit 4.11: Central Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Ayer/Clinton	Ayer, Berlin, Bolton, Clinton, Harvard, Lancaster, Shirley
2	Gardner/Winchendon	Gardner, Hubbardston, Rutland, Westminster, Winchendon
3	Leominster	Lancaster, Leominster
4	Millbury/Grafton	Auburn, Grafton, Millbury, Oxford, Sutton, Worcester
5	Pepperell/Dunstable	Dunstable, Pepperell
6	Spencer/Rutland	Auburn, Brookfield, Charlton, East Brookfield, Leicester, north Brookfield, Oakham, Oxford, Rutland, Spencer, West Brookfield
7	Webster/Southbridge/Charlton	Auburn, Brookfield, Charlton, Dudley, Oxford, Southbridge, Sturbridge, Webster
8	Worcester North	Leicester, Worcester
9	Worcester South	Auburn, Leicester, Worcester

Exhibit 4.12 shows the substation locations within the Central sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically. Many of the locations of substations in the Central sub-region were driven by the need provide electricity to the mills that existed in the early and mid-20th century, which were located along the rivers.

Exhibit 4.12: Central Sub-Region Substation Locations and Study Areas

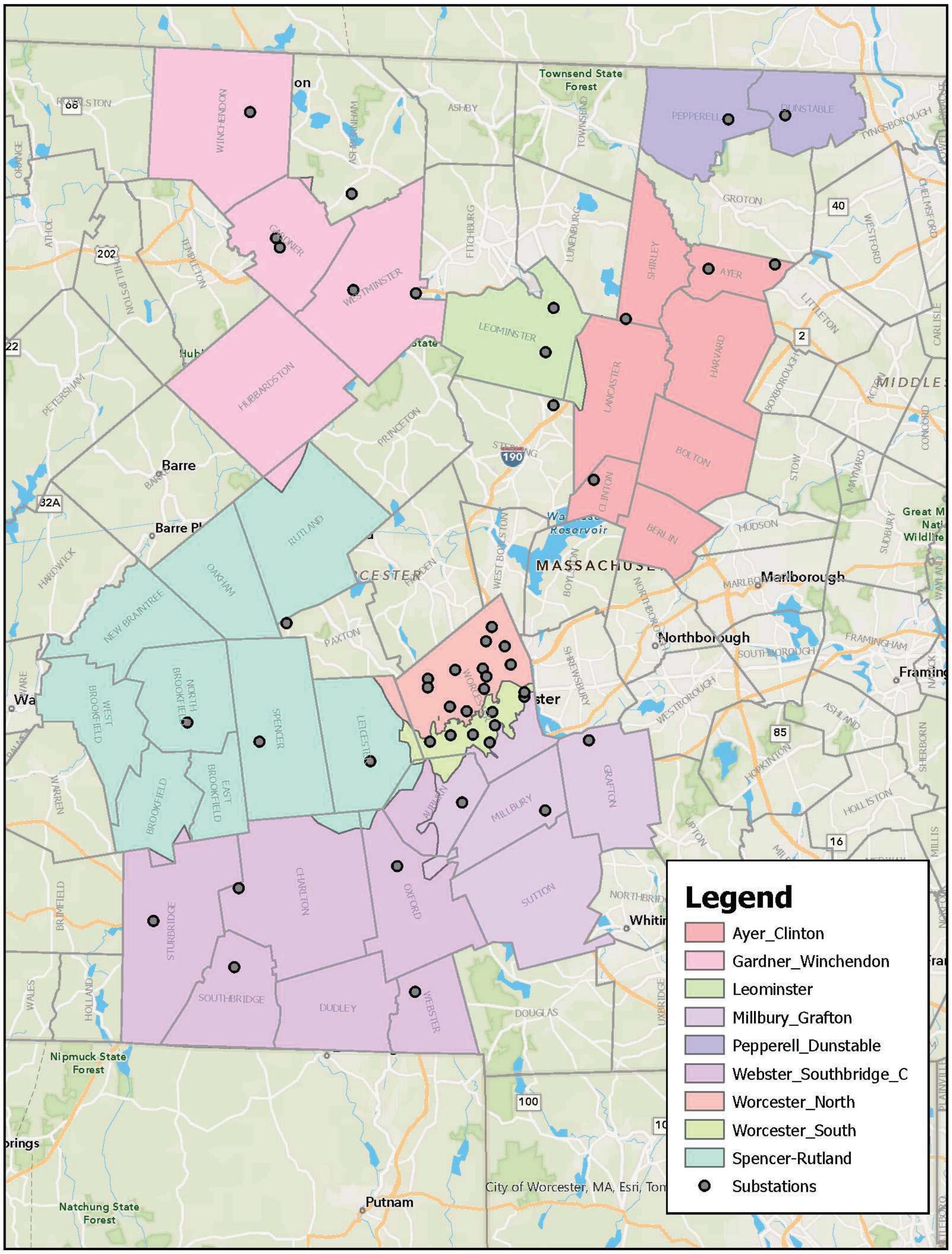
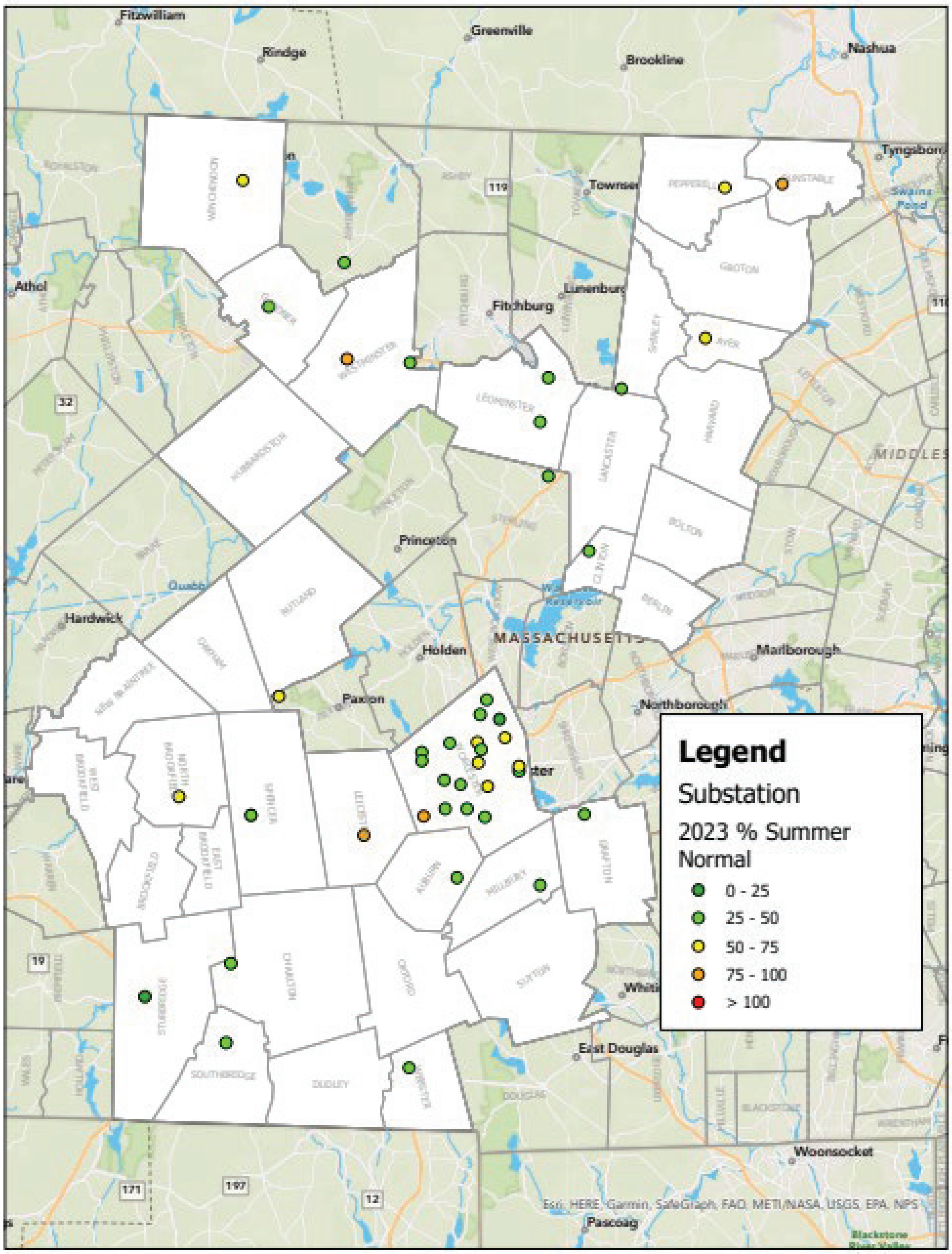


Exhibit 4.12 displays projected 2023 summer normal loading at each substation in the Central region.[8] While no transformers were projected to be loaded over their 100% of summer normal ratings, there are four loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their

[8] The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

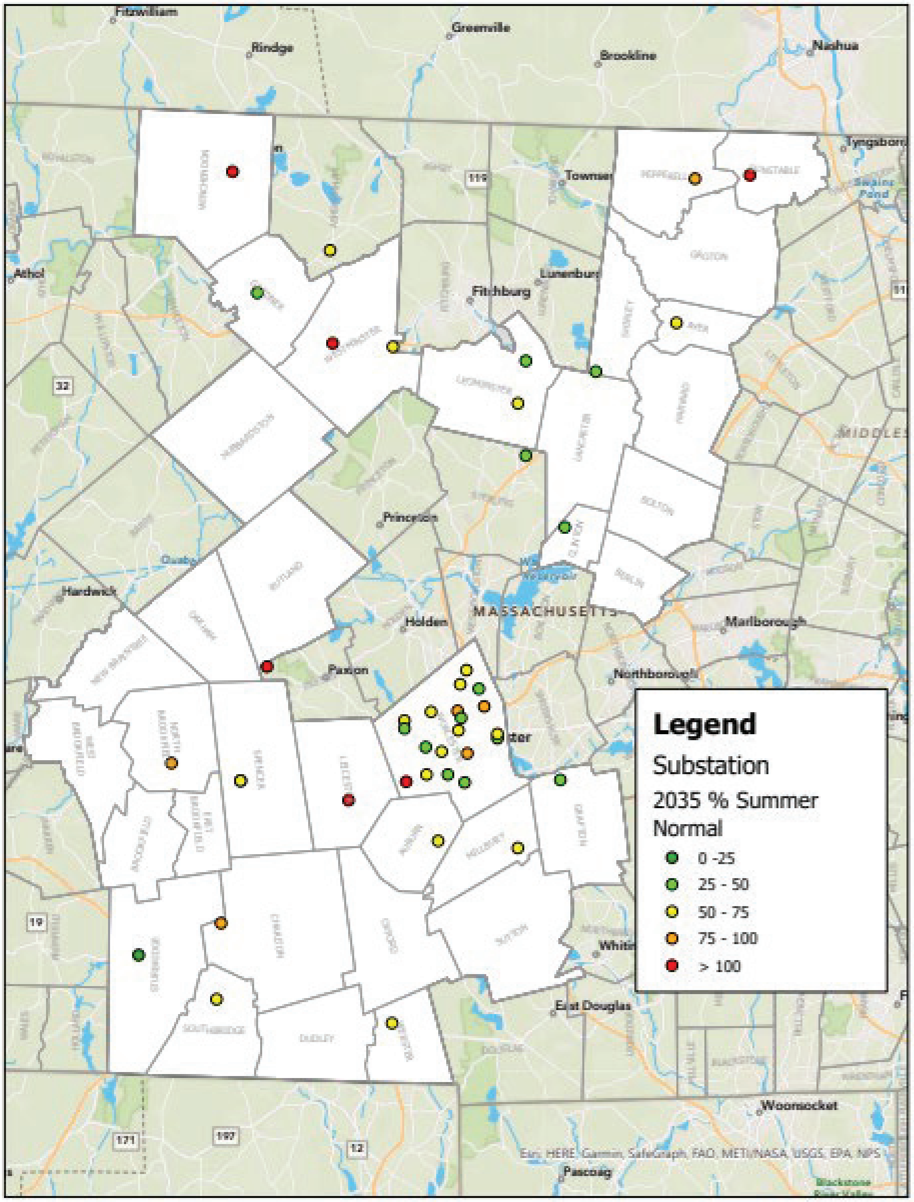
capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

Exhibit 4.13: Central Sub-Region Substation Transformer Loading in 2023



By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Figure 4.14 below shows where the projected overloads will happen.

Exhibit 4.14: Central Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.3.2 Customer Demographics

Exhibit 4.15: Central Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts) [9]	**241,061**	-
Residential	209,604	87%
Residential – Low Income Rate Participants	*31,821*	-
Business, Commercial, Municipal, or University	31,457	13%

The Company serves a total of 241,061 customers in the Central sub-region. Approximately 87% (209,604) of these customers are residential customers and the other 13% (31,457) are comprised of commercial, municipal, or university customers.

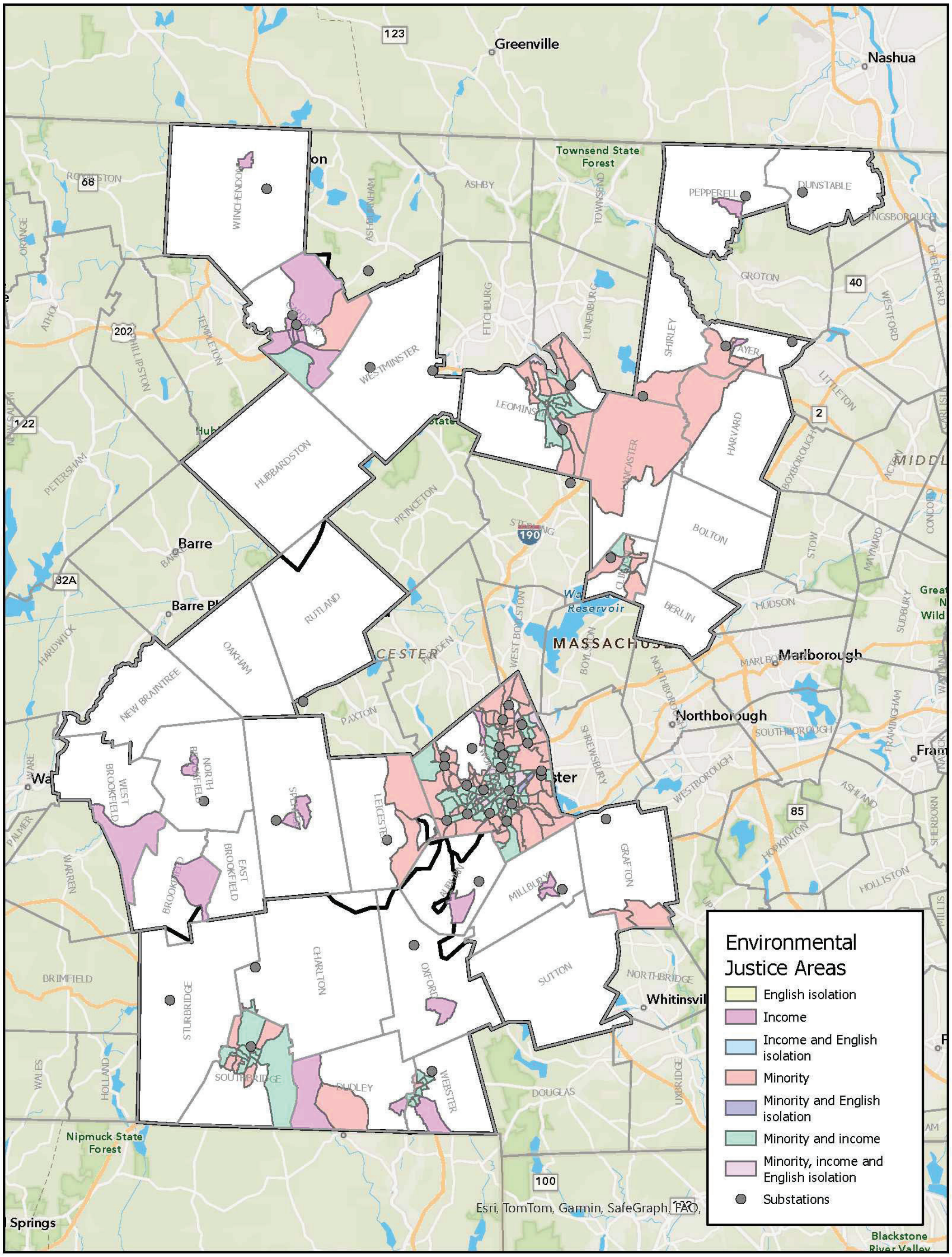
In addition to the Mass Save programs, which have benefited customers in the Central sub-region, 24 municipalities statewide have been identified for targeted outreach per the Massachusetts Energy Efficiency Advisory Council (MA EEAC) Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the Central sub-region are Worcester, Southbridge, and Gardner.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined in Section 3.3, the Company developed a formal Equity and Environmental Justice Policy and Engagement Framework, as well as a complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing. Please refer to the Appendix for those.

Exhibit 4.16 overlays the Commonwealth Environmental Justice Population map with the Company's current substations. [10] The figure below highlights the concentration of substations in many load-dense areas – Worcester, town centers, and other major economic areas with industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[9] Defined as individual accounts, not number of people served.
[10] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map.

Exhibit 4.16: Central Sub-Region Substation Locations in Relation to the Commonwealth's EJCs



4.3.3 Economic Development

The Company's Future Grid Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in this Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the Central sub-region, two communities (Harvard and Worcester) have completed decarbonization plans and 29 are designated as green communities. While economic development strategies vary within the sub-region, the most recent Comprehensive Economic Development Strategies (CEDS) conducted by the Worcester Regional Chamber of Commerce highlights the importance of continuously identifying available and/or underutilized sites and buildings to promote development that increases access to transportation and strengthens utility and telecommunication infrastructure capacity. The CEDS conducted by North Central Massachusetts Chamber of Commerce identifies several industries for retention and development, including advance manufacturing, health care, logistics and distribution, and tourism and small business.

4.3.4 Electrification Growth

Heat Electrification: The Central sub-region has the highest heat pump adoption among the six sub-regions. Approximately 3,000 units have been adopted as of the end of 2022, of which nearly 80% are hybrid.

Transport Electrification: There has been steady growth in the LDEV sales in the Central sub-region with about 3,700 vehicles as of the end of 2022. However, the total number of MHDEVs is less than 10 indicating very low penetration at present. Since 2019, The Company has installed 291 EV charging ports via their phase I and phase II EV charging programs in the Central sub-region.

4.3.5 DER Adoption (Battery Storage and Solar Photovoltaic)

With a total of 631.5 MW of generation connected, the Central sub-region has high DER penetration, representing about 25% of the total DER in the Company's Commonwealth jurisdiction, nearly all of which has been connected in the last decade. Based on national average data, this amount of DER is enough to power nearly 100,000 homes.[11]

Exhibit 4.17: Central Sub-Region DER Capacity Connected and In Queue

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	502.4	155.5
Battery	74.7	379.6
Hydro	3.1	3.5
Wind	0.8	0.0
Miscellaneous	50.5	4.1
Total	**631.5**	**542.6**

[11] According to the Solar Energy Industry Association, the national average for national average (through Q2 2022) of homes powered by a MW of solar is 173. https://www.seia.org/initiatives/whats-megawatt#:~:text=The%20current%20national%20average%20(through,MW%20of%20solar%20is%20173.

Exhibit 4.18 below shows the cumulative amount of connected DER capacity between 2012 and 2023. Note that the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.18: Central Sub-Region Cumulative Connected Generation and Storage

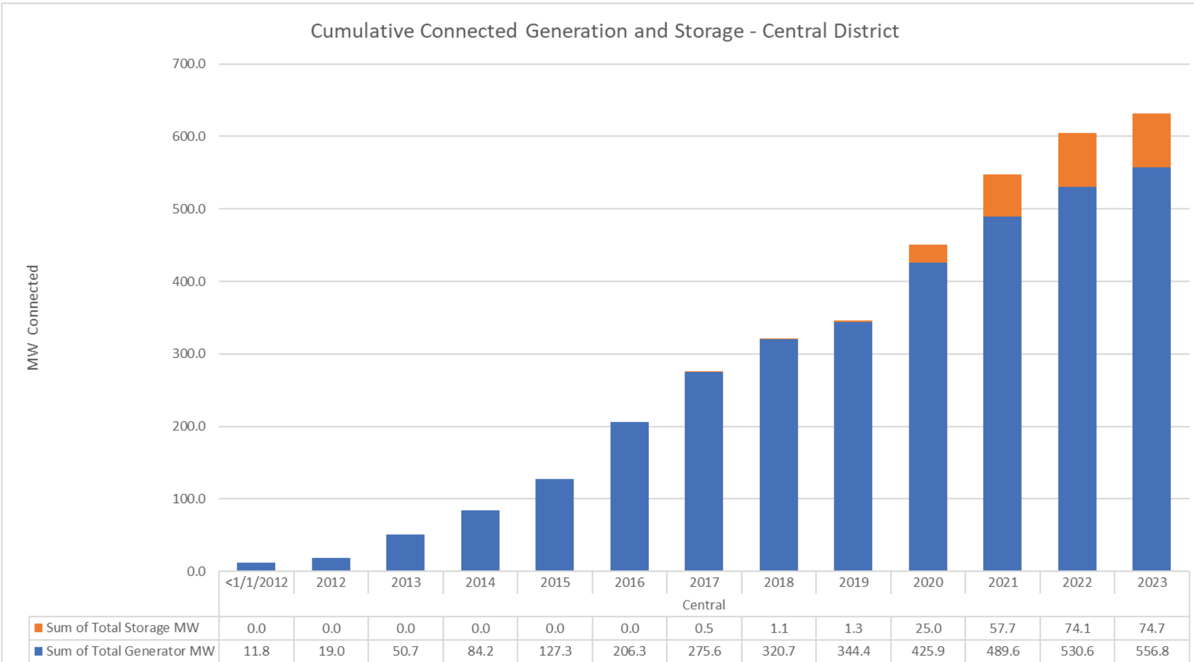
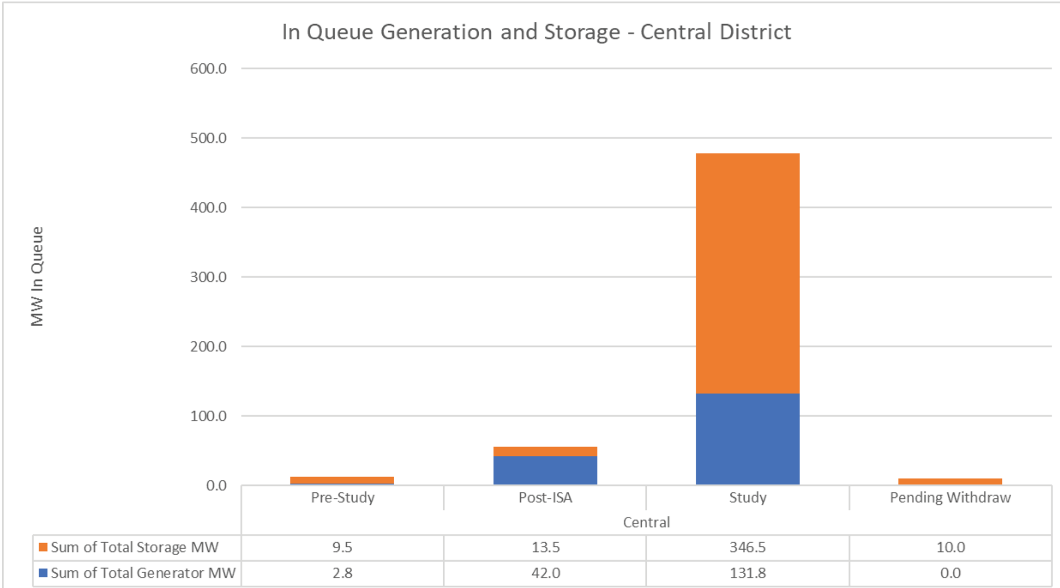


Exhibit 4.19 shows the DER interconnection queue in the Central sub-region as of July 2023. As shown in the exhibit, solar Photovoltaic (PV) represented 45% and batteries represented 54% of the DER capacity in the interconnection queue. Recent application trends have demonstrated a shift from largely solar PV applications to a split between solar PV and battery storage.

A large majority of the batteries are stand-alone, albeit some are co-located as solar PV paired with storage. Unlike other forms of DER, which operate solely in a discharge capacity contributing power to the grid, standalone batteries also must charge from the grid. While most other forms of DER only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency and charge considerations as well as any hosting capacity and discharge constraints, which significantly increases the complexity of planning and operating the network.

Exhibit 4.19: Central Sub-Region pending DER Generation and Storage In Queue



	Pre-Study	Post-ISA	Study	Pending Withdraw
Sum of Total Storage MW	9.5	13.5	346.5	10.0
Sum of Total Generator MW	2.8	42.0	131.8	0.0

Combining the 542.6MW of DER in the interconnection queue, and the 631.5MW already connected in the Central sub-region, the total for the area would be 1,174MW if all in-queue projects as of the above date move forward. While it is unlikely that all will connect, this would result in a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

There are Capital Investment Project (CIP) proceedings underway in this area under the following dockets:

- Gardner Winchendon (Department Docket No. 23-06)
- Spencer Rutland (Department Docket No. 23-09)

In the Central sub-region, the Company has completed or is in the process of completing analyses for a group study on the interconnection of DER in the following study areas.[12]

- Ayer-Clinton
- Millbury-Grafton
- Webster-Southbridge-Charlton
- Leominster
- Worcester North and South

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described in this Future Grid Plan will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process, and Provisional System Planning Provision to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

[12] Only those areas of sufficient maturity for inclusion in the base case of this Future Grid Plan analysis are indicated here. Therefore, this is not a comprehensive list of all areas in which the Company has ongoing group study process.

The high-level benefits of the CIPs to distribution customers include:

- **Reliability**: the solution proposed to safely and reliably interconnect group study DER addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
  - Electrical Power System (EPS) normal configuration thermal loading
  - EPS contingency configuration customer unserved
  - EPS asset conditions
- **Enabled electrification**: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- **Reserved Small Distributed Generation (DG)**: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications required across this sub-region had not been fully identified.

4.3.6 Grid Services (Demand Response, Smart Inverter Controls, Time-Varying Rates)

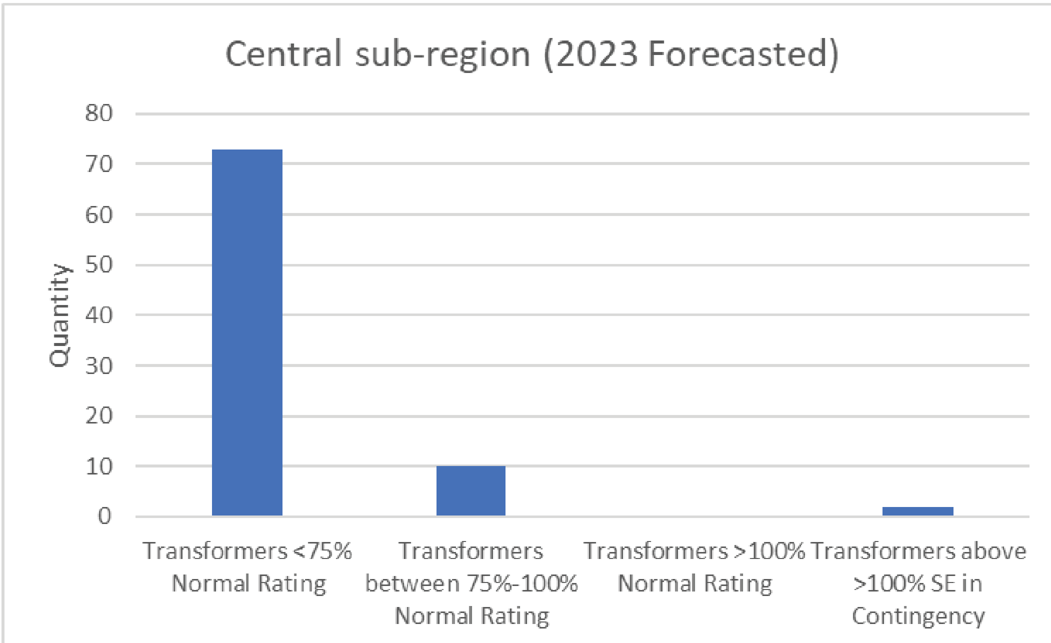
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in Sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Central sub-region, over 4,800 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 32 MW of load on the grid when the overall grid is at peak. This has helped to delay investments and maximize the utilization of the current network.

4.3.7 Capacity Deficiency

The graphs below summarize the forecasted asset loading across the Central sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.20: Central Sub-region 2023 Forecasted Transformer Loading Profile



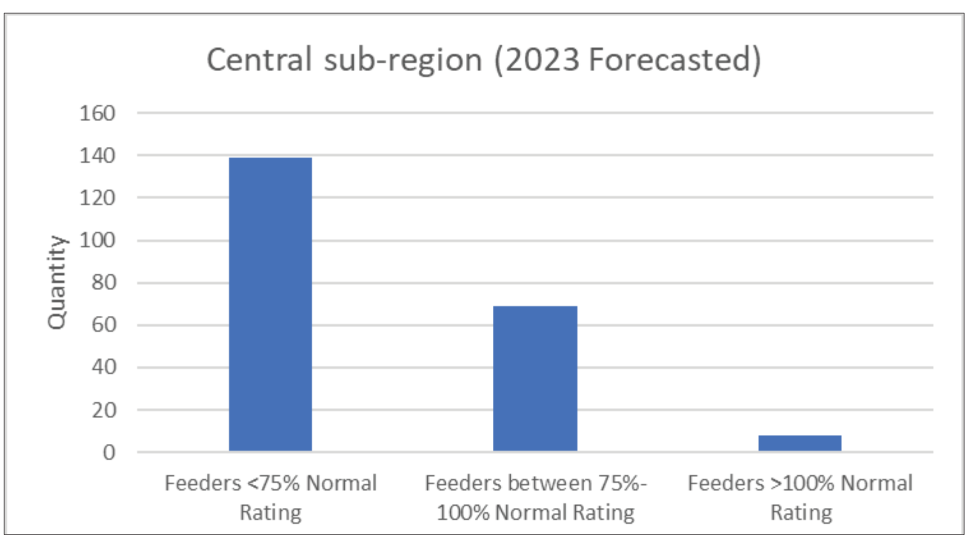
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.21: Central Sub-Region 2023 Forecasted Transformer capacity deficiencies

Study Area	Substation	Capacity Deficiency
Millbury-Grafton	MILLBURY 4	Transformers > 100% Emergency Rating in Contingency
Ayer Clinton	AYER 201	Transformers > 100% Emergency Rating in Contingency

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.22: Central Sub-Region 2023 Forecasted Feeder Loading Profile



Eight feeders in the Central sub-region have an identified existing capacity deficiency. This deficiency is being monitored as anticipated growth and spot loads come into service, and operational mitigations will manage the overload as appropriate. A permanent switching plan was put in place for one projected feeder overload in East Webster.

The Central sub-region has 16 substations that are supplied by 69kV transmission lines. The 69kV transmission lines will be a limiting factor for additional substation capacity in this area. Plans to increase substation capacity must therefore anticipate a future transmission voltage conversion from 69 kV to 115 kV.

The city of Worcester is primarily supplied by the 4.16kV system. The system consists of 80 circuits and 26 substation transformers. A 1902 Worcester Bylaw prohibited overhead wires within a 2-mile radius of Worcester City Hall. The Company's solution to this was to install overhead facilities in over 1,100 customers' backyards with underground cable and switches in the public way. Due to protection concerns, the maximum overhead service transformer size in backyards is 50 kVA. To support the electrification of vehicles and heat in these communities, and with the projected 2050 winter load, maintaining the backyard configuration in this area would require an additional 1,500 backyard transformers, or approximately doubling the existing population impacted. The backyard construction also presents storm restoration challenges due to private property access. The 4kV system is beginning to have normal loading issues and will not be able to support the projected load growth in the area.

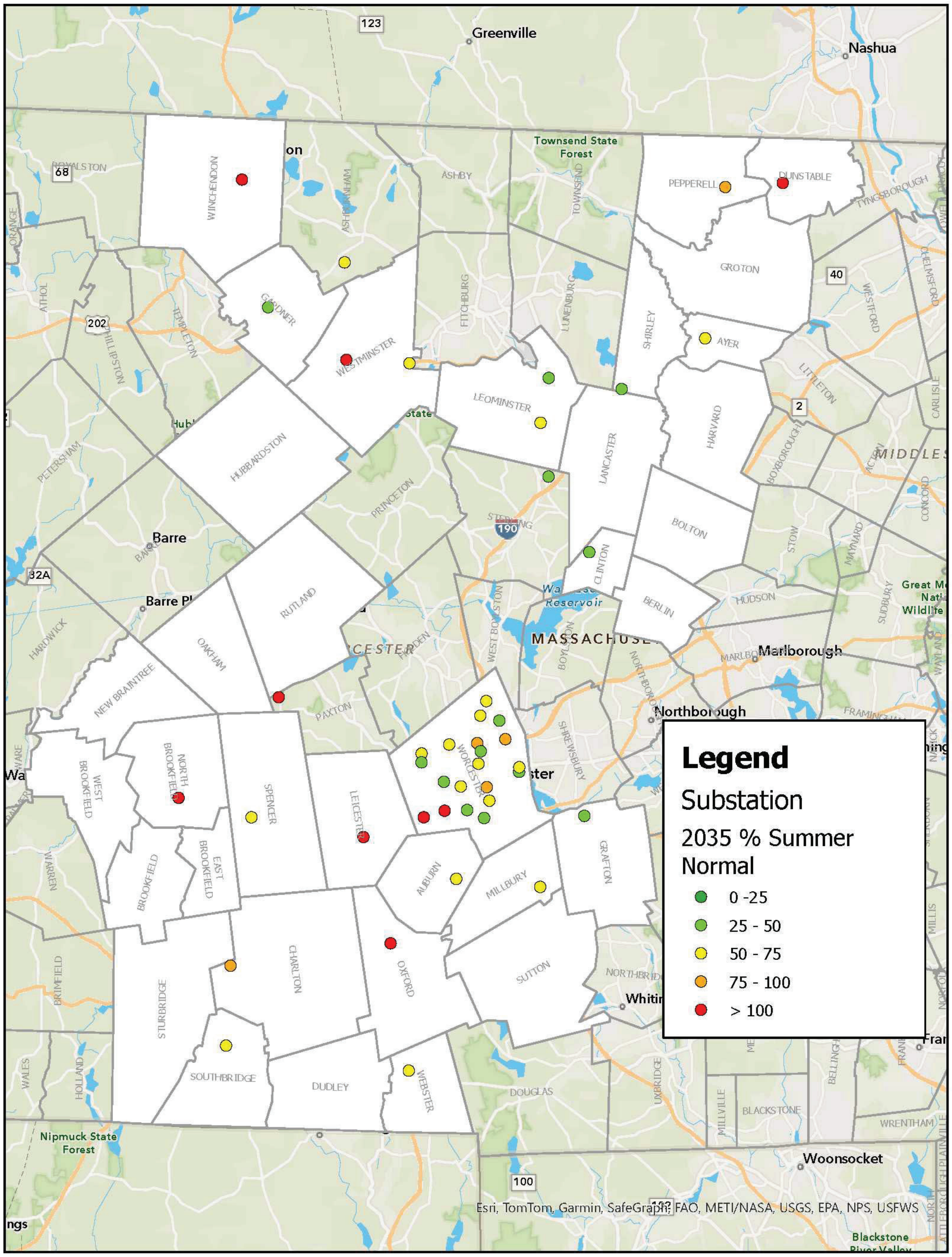
In other words, the existing backyard construction cannot efficiently or reliably support electrification in this region through 2050.

The city of Worcester is also supplied by a non-effectively grounded "High-Tension" system that operates at 13.8kV.[13] The non-effectively grounded system presents challenges for DER interconnections, including technical requirements that impose high cost and/or real estate requirements on these projects that often render them inviable.

Although the Company can safely manage transformer overloads today using operational measures or planned investments outside of the ESMP, looking out 10 years to 2035, the equipment will not be able to accommodate the forecasted load growth. The Company must invest in additional system capacity to support the forecasted load growth in this sub-region due to electrification. Exhibit 4.23 maps 10-year forecasted transformer data to approximate substation load as a percentage of capacity in the Central sub-region, providing a visual for these forecasted overloads.

[13] This system was called "High-Tension" at the time of its installation in the early 1900s to refer to the fact that these circuits operated at a higher voltage or "tension" and functioned as sub-transmission supply to other substations, while most distribution facilities were operated at 2.4 kV. The Company has maintained this legacy naming convention for these unique non-effectively grounded circuits, even though the Company no longer thinks of 13.8 kV as a "high" voltage and these lines are now also used to supply customers directly.

Exhibit 4.23: Substation Load As A Percentage of Capacity Across The Central Sub-Region in 2035, Assuming No Capacity Expansion[14]



[14] Substations without summer normal ratings data were omitted from this map.

4.3.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of “core operations” and additional funding is not proposed in this Future Grid Plan. The Future Grid Plan focuses strictly on infrastructure investments driven by load growth and the need to increase system capacity.

The Company makes decisions on replacing assets based on the asset conditions and risk profile. However, the age profile of an asset is easily measurable and often correlates to its condition. The longer an asset is in service the higher the likelihood it is to have experienced stresses that could weaken its condition. These stresses include extended heavy loads due to extended periods of heat waves, or fault conditions. The Company assesses the actual condition and performance of assets through a variety of means including inspections, maintenance activities and specific condition analyses on some assets. The Company considers various factors such as safety, reliability, maintenance and repair, spare parts, and obsolete technology in the decision making and prioritization of asset condition replacement projects.

Although the Company has done an exceptional job maintaining assets and keeping them in service beyond their life expectancy, older assets may require more frequent and extensive maintenance and repairs to keep them in good operational condition especially as they become stressed due to heavier loading driven by accelerating electrification. In addition, with older assets it is more challenging to find replacement parts and components, which can result in delays to repairs or slower response to emergency conditions potentially allowing those conditions to worsen. Aging assets even may pose safety risks due to deteriorating condition. These risks can lead to accidents or malfunctions, prompting the need to address them more urgently.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future customer demands. However, as noted above, the Company makes decisions based on asset condition and risk rather than time of life.

The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

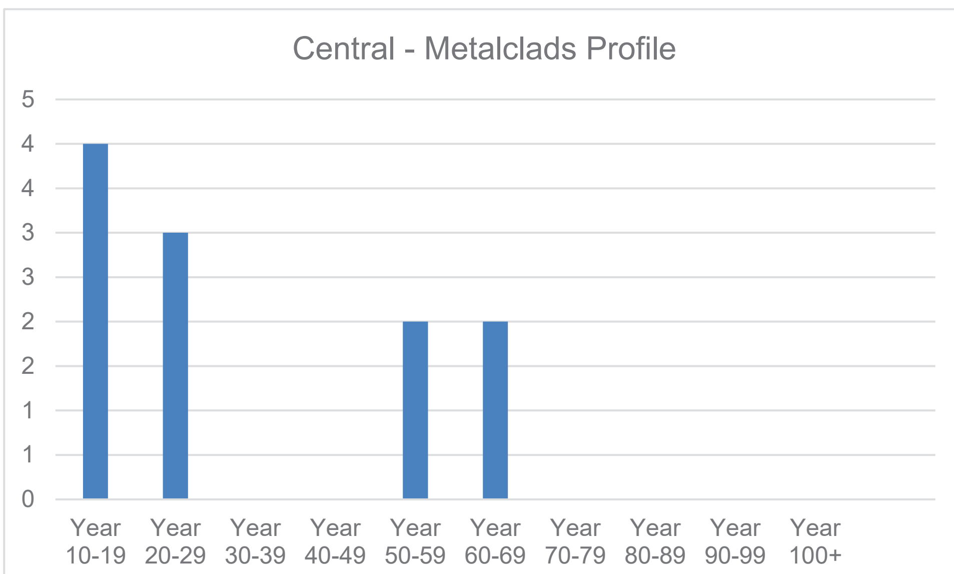
Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

An additional aspect of updating aging infrastructure is to keep the technologies and materials up to date with current digitalization or environmental standards. As the Company moves towards modernizing the grid, existing equipment may need to be modified or replaced in order to be compatible with new digital management tools needed for a bidirectional electric power system. Additionally, equipment may need to be updated to meet environmental standards, such as upgrading substation support structure design from aluminum to steel due to increased operating efficiency.

The following Exhibits illustrate the age of key components of energy infrastructure today. Many of these assets are approaching the end of life and will require condition-driven replacements in the future.

Metalclad, or Metalclad Switchgear, refers to a key substation component in certain types of substations. Metalclad switchgear is a metal building that houses circuit breakers, protective relays and controls, and bus, typically on the low-voltage side of the substation transformer.[15] Since all the circuit breakers, protection and control, communications, metering, and auxiliary equipment are enclosed within the switchgear enclosure, it provides one of the most compact and economical approaches to building a multiple feeder distribution substation. This provides a controlled environment for the batteries and the protective relays, metering, and monitoring devices. Maintenance of much of the substation equipment can be performed without hindrance from weather conditions. Key age-related concerns for metalclad switchgear are related to the degradation of the metal enclosure, which may allow water and animal intrusions that lead to equipment damage and/or outages to all or some of the feeders supplied by the metalclad. Exhibit 4.24 below shows the Metalclad profile in the Central sub-region.

Exhibit 4.24: Central Sub-Region Metalclad Age Profile



[15] IEEE Std. C37.20.2-2015 Standard for Metal-Clad and Substation-Type Cubicle Switchgear and NEMA standards SG-5 and SG-6 define the necessary technical characteristics for metalclad switchgear.

Exhibit 4.25 below shows the **substation transformer** age profile in the Central sub-region.

Exhibit 4.25: Central Sub-Region Substation Transformer Age Profile

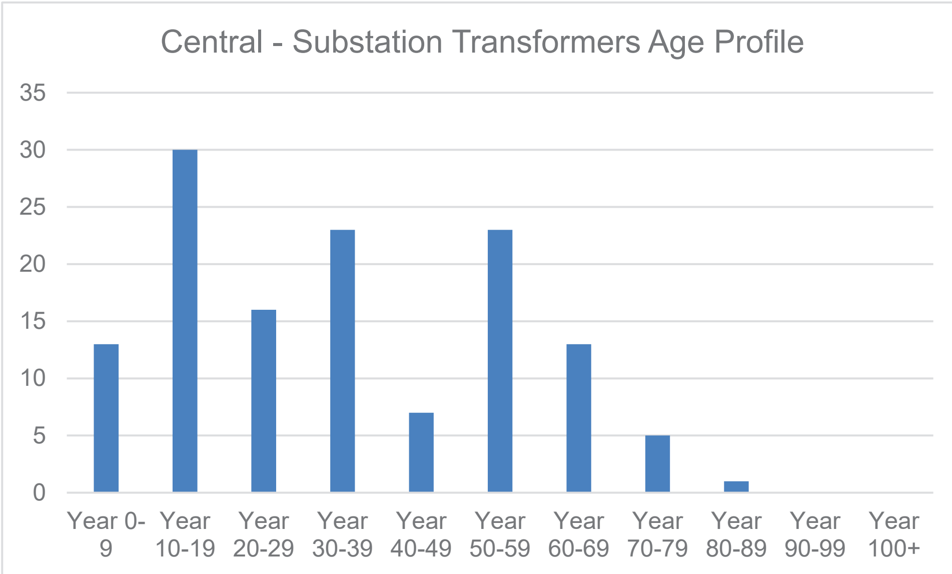
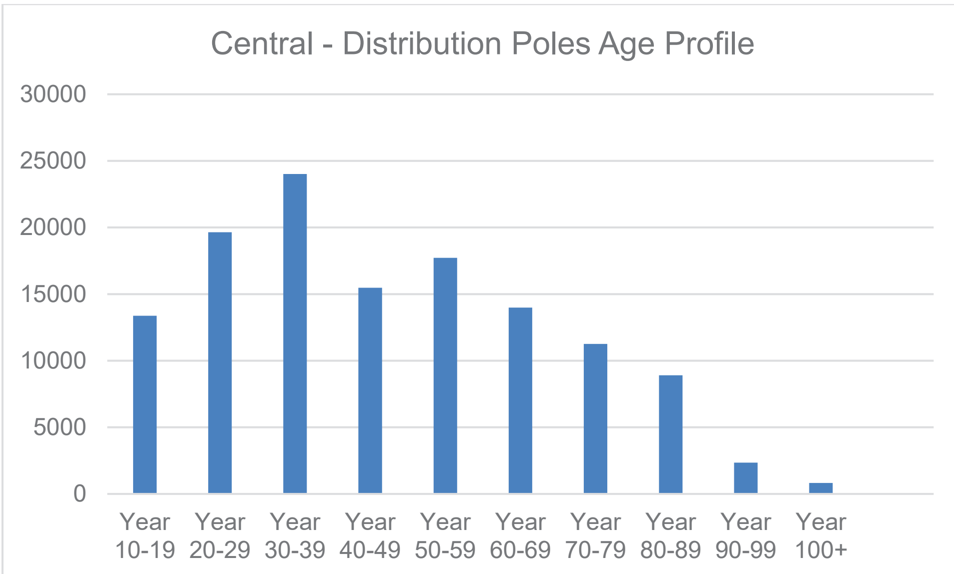


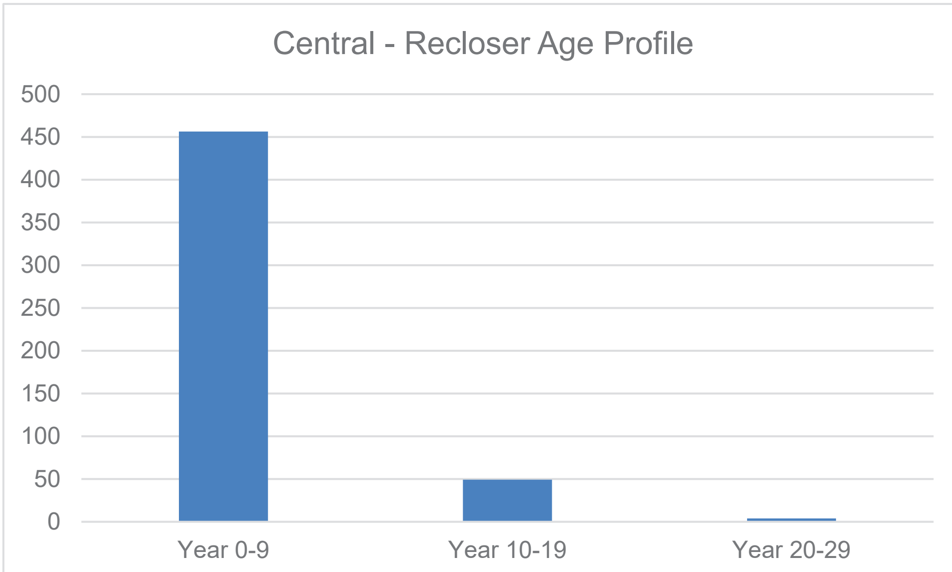
Exhibit 4.26 below shows the **distribution pole** age profile in the Central sub-region.

Exhibit 4.26: Central Sub-Region Distribution Pole Age Profile



Reclosers are pole-mounted distribution line equipment which respond to faults by opening to isolate the sections of circuits that are damaged. They can “reclose,” attempting to restore power following the fault several times before finally locking out if the damage is permanent and must be repaired by line crews before the line can be safely re-energized. This reclosing behavior means that for temporary faults, (e.g., a branch that falls across the wires and then falls to the ground), customers only experience a momentary outage. Reclosers can also work in automated schemes such as FLISR, to reconnect and restore portions of customers in a more sophisticated and coordinated manner than the simple isolation of faults. Exhibit 4.27 below shows the recloser age profile in the Central sub-region.

Exhibit 4.27: Central Sub-Region Recloser Age Profile



4.3.9 Reliability and Resilience

This Section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality Guidelines.[16] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this Future Grid Plan.

As described in detail in Section 10, reliability issues are largely due to abnormal and/or hazardous conditions, such as flooding, high winds, and wildfire, and are not directly driven by increased electrification. However, as society electrifies and becomes more dependent on the electric network, it will be important for the Company to maintain, if not improve, system reliability and resiliency despite the increased challenges in the way. While none of the investments in this Future Grid Plan are directly prompted by reliability considerations, there are synergies from the Future Grid Plan that also improve customer reliability by coincidence.

In the Commonwealth, the Company has historically adopted System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), all defined below, as the standard metrics for quantifying the quality of service experienced by customers during "blue-sky days" (i.e., excluding major storms). The interruptions included in the formulas and results shown below are interruptions lasting longer than 1 minute, referred to as "sustained outages." Further exclusions of events not reported include major storms, loss of supply events during blue-sky days, planned outages during blue-sky days, and customer-equipment outages during blue-sky days.

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[16] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

SAIDI means the total duration of customer interruptions in minutes divided by the total number of customers served by the distribution Company, expressed in minutes per year. SAIDI characterizes the average length of time that customers are without electric service during the reporting period. It is commonly measured in minutes or hours of interruption and is mathematically expressed as:[17]

$$SAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption\ (CMI)}{Total\ Number\ of\ Customers\ Served}$$

SAIFI means the total number of customer interruptions divided by the total number of customers served by the distribution Company, expressed in number of interruptions per customer per year. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period. It is mathematically expressed as:

$$SAIFI = \frac{\sum Total\ Number\ of\ Customers\ Interrupted\ (CI)}{Total\ Number\ of\ Customers\ Served}$$

CAIDI means the total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year. If the total number of customers connected to the circuit differs from interruption to interruption, then the average number of customers served by that circuit shall be used. CAIDI characterizes the average length of time customers connected to a circuit are without electric service during the reporting period. It is mathematically expressed as:

$$CAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption\ (CMI)}{Total\ Number\ of\ Customers\ Served} = \frac{CMI}{CI} = \frac{SAIDI}{SAIFI}$$

These metrics are standardized for reliability tracking across the utility sector; baselines and comparisons with other utilities can be enabled not just on performance but also in relation to technology deployment and other reliability improvement mechanisms.

As mentioned above, the metrics are called “blue-sky” reliability metrics, where major storm events are typically excluded. This allows for the drivers of day-to-day reliability and the actual 24/7 customer experience to be discernible. The drivers of reliability, the day-to-day customer experience, have the potential to be inherently different from the drivers of major storm performance, is referred to as resilience events. Therefore, it is necessary to separate major event experience from day-to-day customer experience.

However, SAIDI and SAIFI can be similarly used as a basis to quantify system performance during major events for system resiliency purposes, by creating a parallel SAIDI/SAIFI evaluation that includes all sustained outages (i.e., outages with duration longer than 1 minute) at all times, during major events in the calculation. Those are referred to as All-In SAIDI and All-In SAIFI. Since

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[17] [1] IEEE 1366-2012

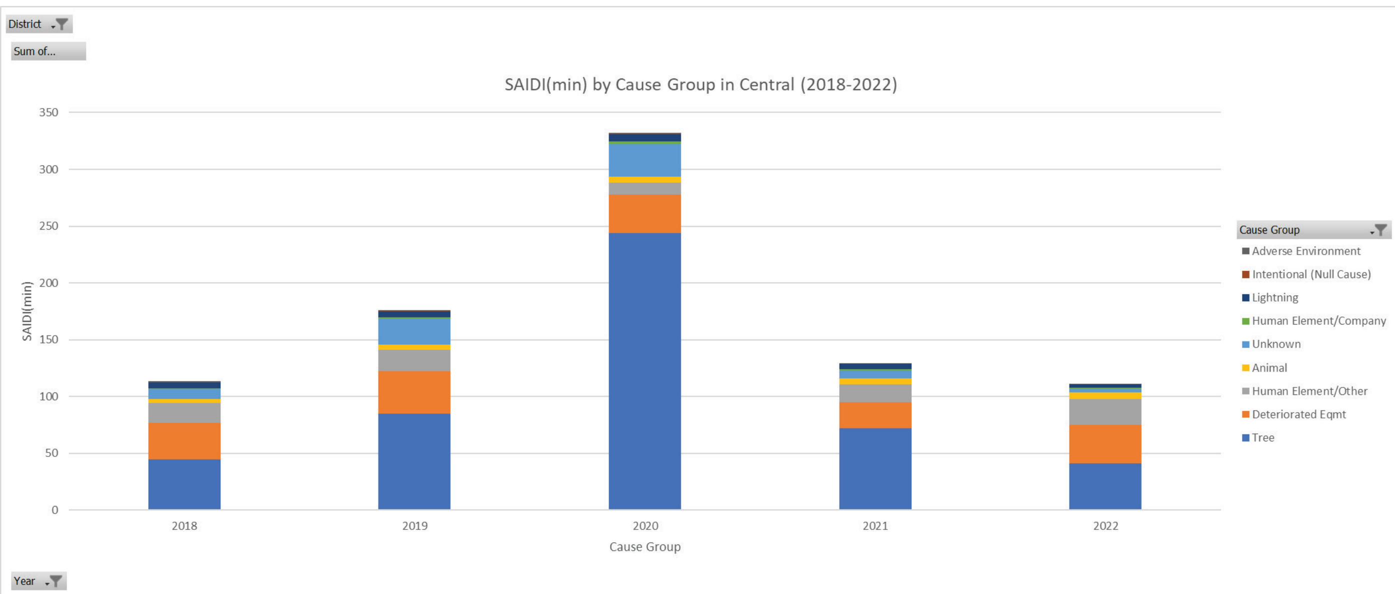
reliability is a subset of resiliency, the continuum of the customer experience from blue-sky to black-sky is best represented by using parallel, comparably devised metrics. This is also the best approach to understand and account for the impact of resiliency measures on reliability, and vice versa.

Reliability performance

The exhibits below show the reliability performance of the Central sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region.

Tree-related events caused the majority of outages across this sub-region, in terms of duration and frequency.

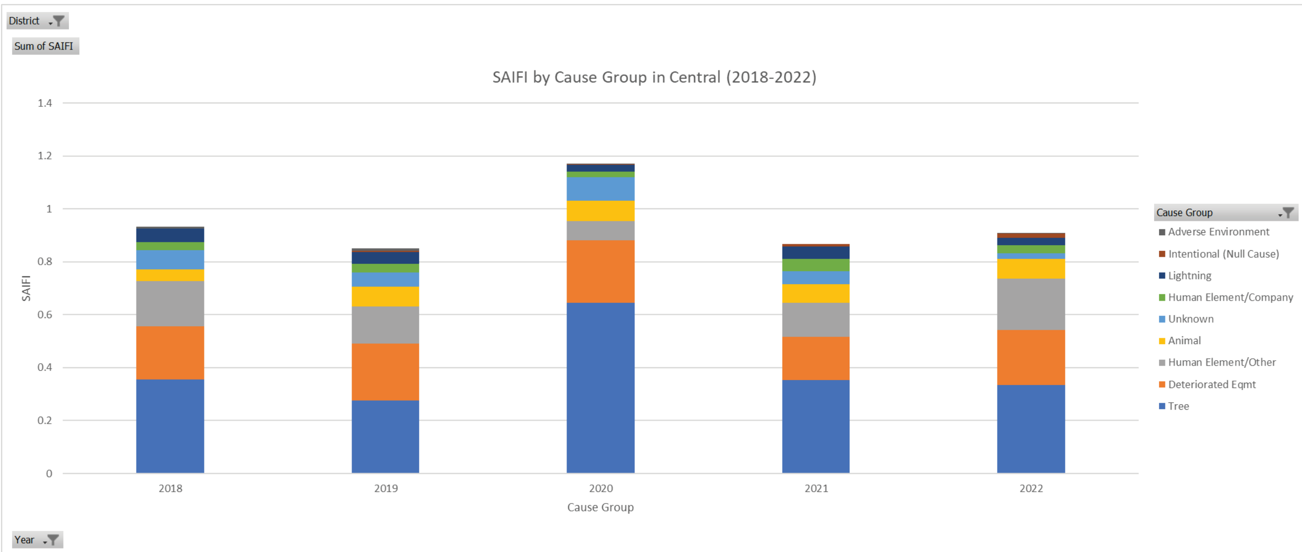
Exhibit 4.28: Central Sub-Region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance



The IEEE Guide for Electric Power Distribution Reliability Indices, Standard 1366, was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for three out of the last five years, Central has been in the first or second quartile for frequency of outages (SAIFI) and has been in the second quartile for the past four years for duration (SAIDI).

SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
3rd Quartile	1st Quartile	2nd Quartile	2nd Quartile	3rd Quartile

Sum of SAIDI Medium Quartile				
2018	2019	2020	2021	2022
3rd Quartile	2nd Quartile	2nd Quartile	2nd Quartile	2nd Quartile



The sub-region-specific indices above are calculated using outage and electric customer counts specific to the sub-region. This can facilitate comparison between sub-regions. For example, the average customer in sub-region A experienced more/fewer outage minutes in a given year than the average customer in sub-region B but these sub-region values cannot be added together to arrive at the total system-level indices for that year, and so cannot be used to understand how much of a given year's system-level reliability performance was attributable to a given sub-region.

Resiliency performance

Outage impacts from major events are traditionally excluded from reliability reporting, as described above. Major events can contribute both significant durations and numbers of outages to SAIDI and SAIFI calculations, sometimes dwarfing the characterization of system performance for 364 days of the year based on the impacts from a single day. Nonetheless, analysis of system performance trends that include the impacts from these major events can provide valuable insights into how the system responds to these significant stressors, which are growing increasingly frequent due to climate change.

The Company calculated "all-in" SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. Note that due to the "low frequency high impact" nature of significant events that are excluded from traditional reliability reporting, the Company continues to monitor these trends and whether they are sustained over time.

For this analysis, the Company aggregated the outage events experienced at each of its substations over a 5-year period 2018-2022 and calculated the resulting substation-level SAIDI and SAIFI. This calculation included all events, including major storms. The resulting SAIDI and SAIFI values for each substation were then ranked for all the Company's service territory. Tier designations were made to indicate each substation's performance relative to all other Company substations for this time period. Note: these tiers illustrate internal benchmarking for relative comparison between the Company's substations across its service territory and differ from the IEEE metrics and benchmarking analysis described in the preceding section. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with Environmental Justice Areas, as defined by the Commonwealth. The exhibits below show the Company's distribution substation locations within the given sub-region overlaid with Environmental Justice Areas. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company's entire population of substations. A greater density of distribution substations, typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the Environmental Justice Areas fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company's distribution substations.

Exhibit 4.29: Central Sub-Region Resiliency in EJCs as shown as SAIDI Substation Performance

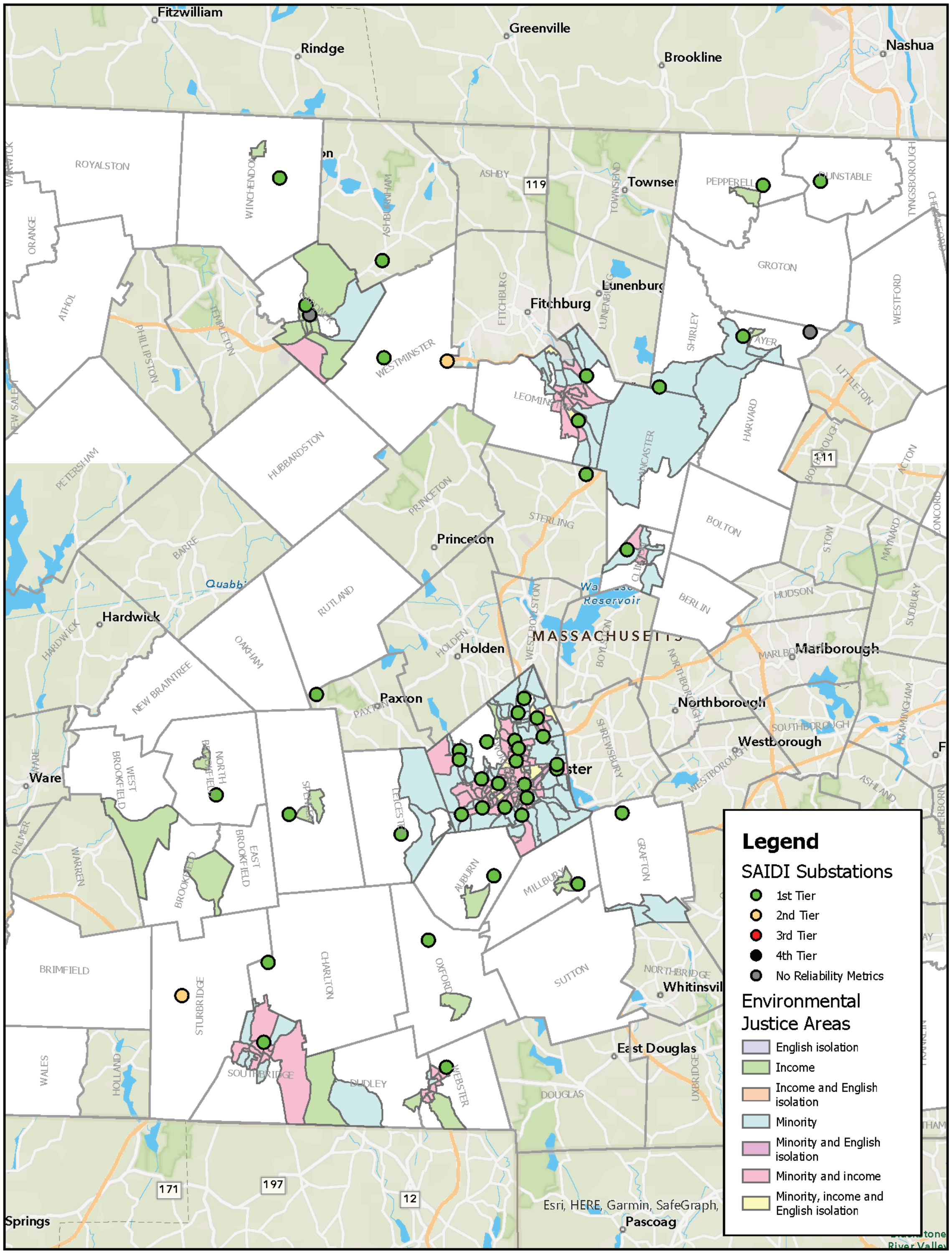
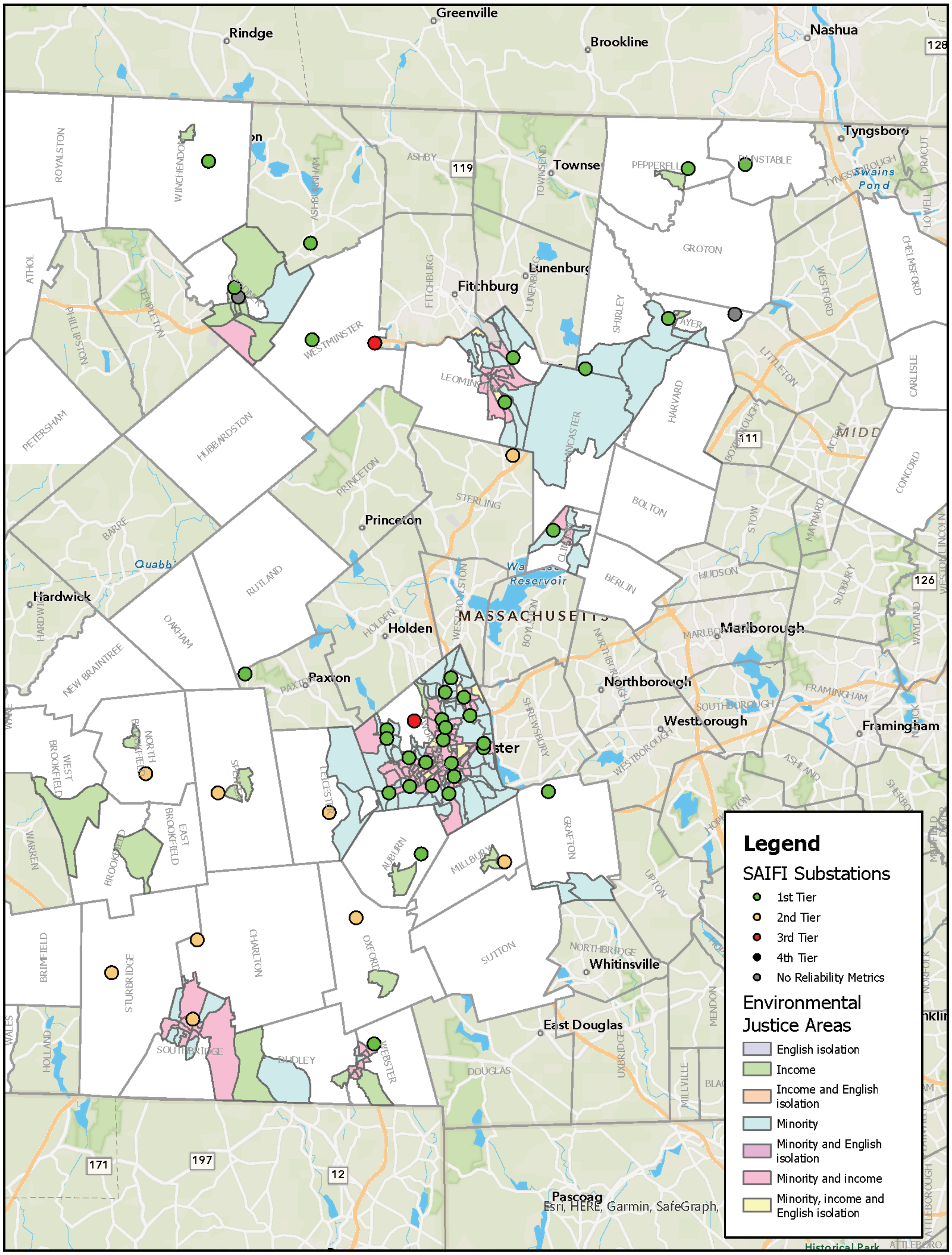


Exhibit 4.30: Central Sub-Region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was a particularly bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.3.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the Energy Facilities Siting Board (EFSB) review process is triggered to ensure the work is in compliance with state requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability municipality to municipality and year to year, which makes it challenging to generalize regionally. For example, in the central region, the Company has energy infrastructure in urban and rural locations. Each of these settings present different siting and environmental considerations.

4.4 Merrimack Valley Sub-Region

Nature of the Area: The Merrimack Valley sub-region is predominantly suburban, with regional urban centers in Lowell and Lawrence. Smaller urban/town centers can be found in Amesbury, Haverhill, Methuen, and Newburyport.

Exhibit 4.31 Merrimack Valley Sub-Region Customers by the Numbers

Description	Value	Unit
Number of Substations	58	Count
Number of Feeders	297	Count
Total Length of Feeders	3,400	Miles
Total Peak Load Served	1,212	MW
Sub-region Area	386	Square Miles
Benefits of EE	1,331,336	MWh
Heat Pump Adoption	1,225	Count
Charging Ports Installed	379	Count
5- Year Residential Population Growth Projections	1.7%	Percent
5- Year Forecasted Load Growth	6.9%	Percent
Existing Connected Rooftop DER (< 25kW)	105	MW

Context of the region

The Merrimack Valley sub-region includes some of the most consistently dense communities in the Commonwealth. This sub-region has average levels of DER penetration relative to all other sub-regions due to the somewhat limited amount of open space coupled with more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the large population and growing suburban areas, an approximate 6.9% load growth is expected in the central region in the next five years. Additional details can be found in Section 5.

Below are some key characteristics of the Merrimack Valley sub-region which will drive future investment needs.

Exhibit 4.32 Merrimack Valley Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are 77 circuits that operate at 4.16 kV which primarily supply Andover, Lawrence, and Lowell, and are supplied from substations that step down the voltage of 13 kV or 23 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the Commonwealth. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
An extensive 23 kV class subtransmission system in the area acts both as supplies to substations and to serve mostly larger load customers.	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both the substation and extend transmission facilities into these areas to meet the projected load growth.

4.4.1 Maps

The Company's Merrimack Valley sub-region consists of 18 municipalities and comprises the study areas below:

Exhibit 4.33: Merrimack Valley Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Amesbury/Newburyport	Amesbury, Haverhill, Newbury, Newburyport, Salisbury, West Newbury
2	Billerica	Billerica, Chelmsford, Tewksbury
3	Chelmsford/Westford	Chelmsford, Lowell, Tyngsborough, Westford
4	Dracut	Andover, Dracut, Lowell, Methuen, Tewksbury
5	Haverhill	Boxford, Haverhill, Methuen, North Andover
6	Lawrence	Lawrence, Methuen

7	Lowell	Chelmsford, Lowell, Tewksbury
8	Methuen	Dracut, Haverhill, Lawrence, Methuen
9	North Lowell	Dracut, Lowell, Tyngsborough
10	Tewksbury	Andover, Billerica, Lowell, Tewksbury

Exhibit 4.34 below shows the substation locations within the Merrimack Valley sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow municipal lines because they are defined electrically instead of geographically. Many of the locations of substations in the Merrimack Valley sub-region were driven by the need to provide electricity to the mills that existed in the early and mid-20th century, which were located along the rivers. Recent revitalization and economic development have resulted in conversion of many of these mill properties to residential and commercial businesses.

Exhibit 4.34: Merrimack Valley Sub-Region Substation Locations and Study Areas

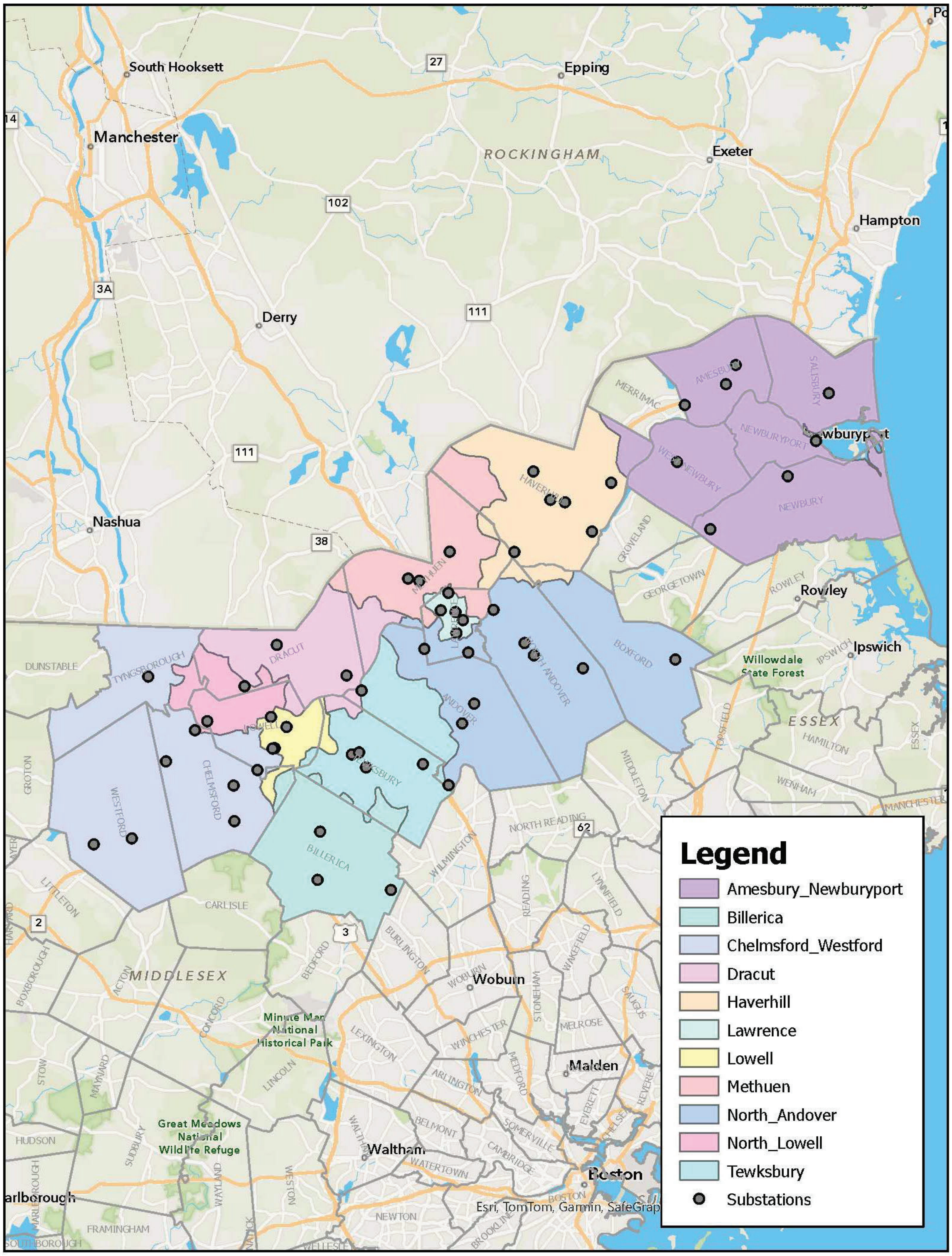
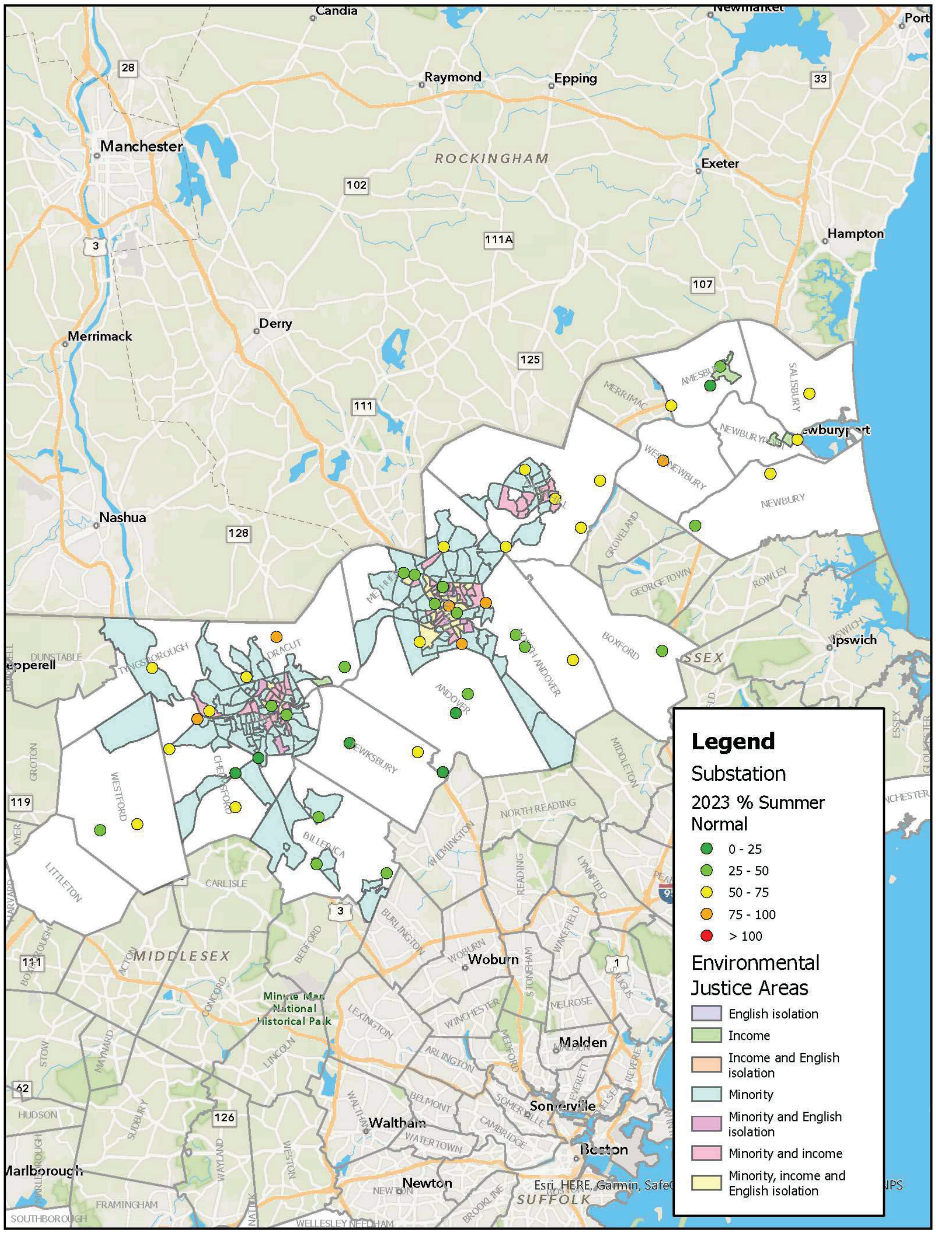


Exhibit 4.35 displays projected 2023 summer normal loading at each substation in the Merrimack Valley region.[18] While no transformers were projected to be loaded over their 100% of summer normal ratings, there are six loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

Exhibit 4.35: Merrimack Valley Sub-Region Substation Transformer Loading in 2023



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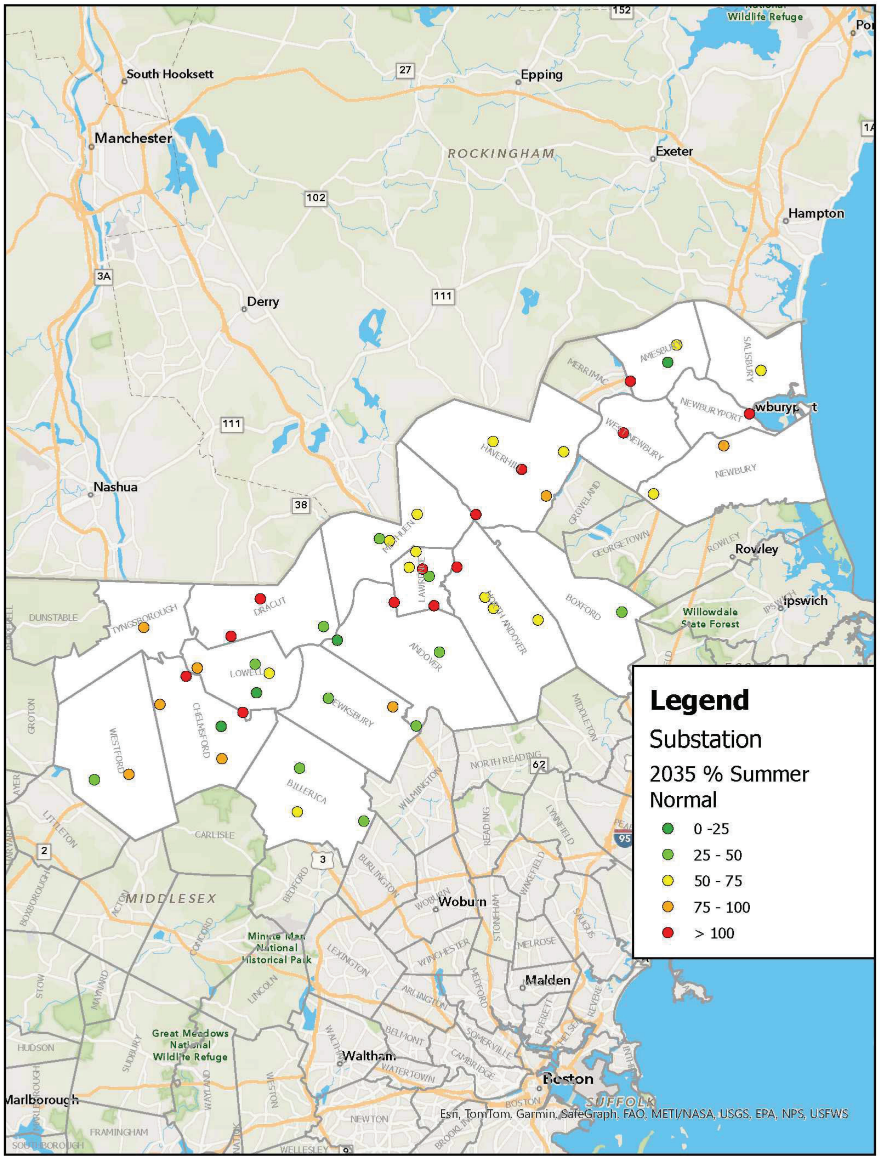
18 The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Figure 4.36 below shows where the projected overloads will happen.

Exhibit 4.36: Merrimack Valley Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.4.2 Customer Demographics

Exhibit 4.37: Merrimack Valley Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts)	**263,871**	-
Residential	231,279	88%
Residential – Low Income Rate Participants	*32,181*	-
Business, Commercial, Municipal, or University	32,592	12%

The Company serves a total of 263,871 customers (defined by individual accounts, not the number of people served) – in the Merrimack Valley sub-region. Approximately 88% (231,279) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

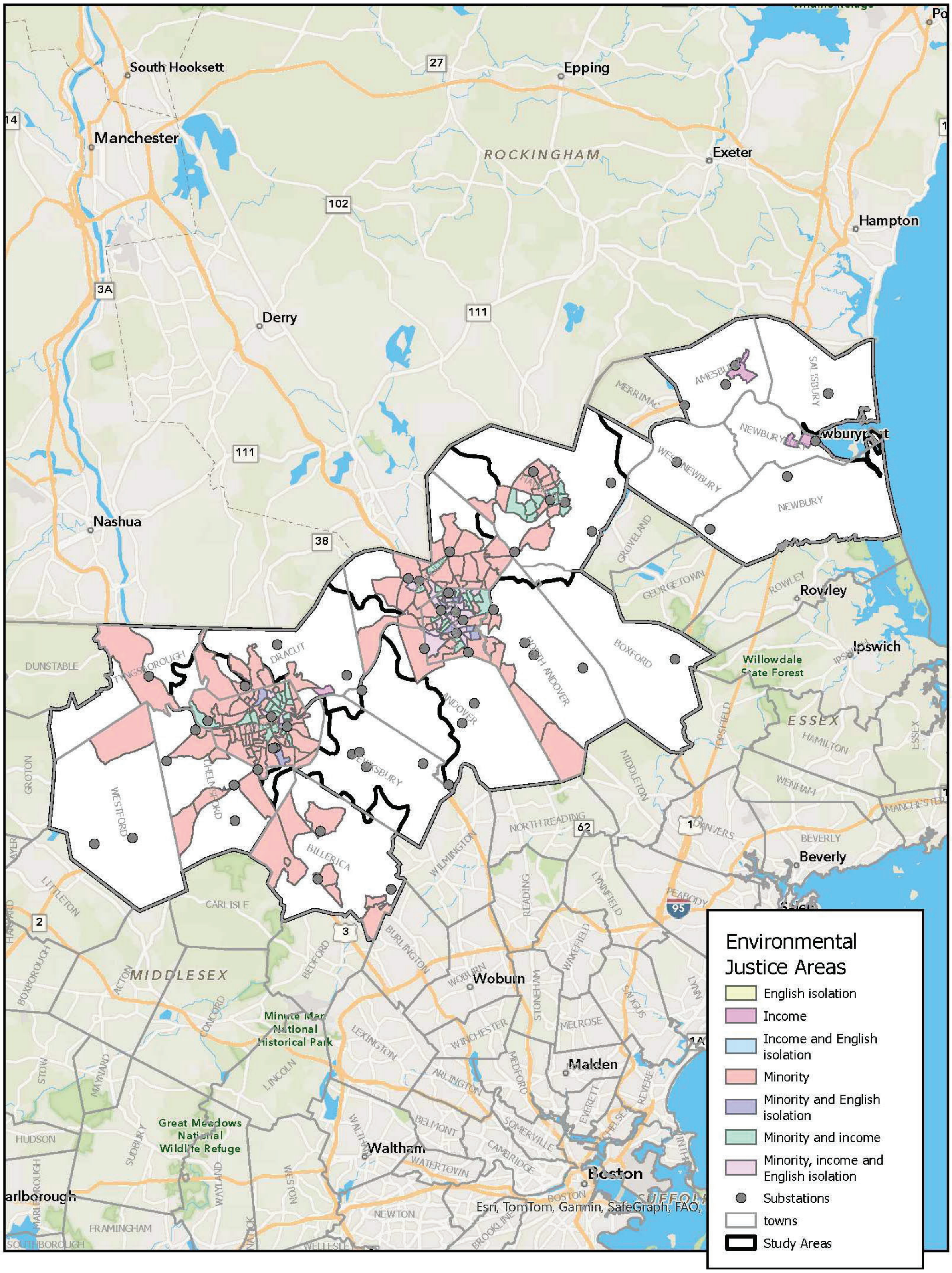
In addition to the Mass Save programs, which have benefited customers in the Merrimack Valley sub-region, 24 municipalities statewide have been identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the Merrimack Valley sub-region are Billerica, Lawrence, Lowell, and Methuen.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing. Please refer to the Appendix for those drafts.

Below please see Exhibit 4.38 which overlays the Commonwealth Environmental Justice Population map with the Company's current substations.[19] Exhibit 4.38 below highlights concentrations of substations in many load-dense areas – Lawrence, Lowell, municipal centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[19] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map.

Exhibit 4.38: Merrimack Valley Sub-Region Substation Locations in Relation to the Commonwealth's EJCs



4.4.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the Merrimack Valley, two communities (Westford and Newburyport) have completed a decarbonization plan, two communities, in partnership with the Company, have completed a SEMP, and all 13 communities are designated as green communities. The region's focus over the next five years is to increase the supply of affordable housing, promote workforce development, enhance connectivity to public transportation, and develop available commercial and industrial space. Each of these initiatives are supported by programs such as MassDevelopment's Transformative Development Initiative (TDI). This initiative targets Gateway Cities to accelerate economic growth at the neighborhood level, while CEDS envisions the region as a climate-resilient community and economic activity hub through vibrant downtowns, main streets, commercial districts, and outdoor spaces. These and other programs are supported by local leaders, developers, and regional organizations such as The Lowell Plan, Lowell Chamber of Commerce, UMASS-Lowell, Middlesex 3 Coalition, Merrimack Valley Chamber of Commerce, regional banks and numerous social service agencies.

4.4.4 Electrification Growth

Heat electrification – Merrimack Valley has moderate heat pump adoption with about 850 units installed by the end of 2022, of which nearly 60% are hybrid.

Transport electrification – There has been consistent growth in LDEV sales in Merrimack Valley to date with a moderate amount of about 5,000 vehicles purchased cumulatively. The MHDEV count still remains extremely low. Since 2019, the Company has installed 379 EV charging ports via the phase I and phase II EV programs in the Merrimack Valley sub-region.

4.4.5 DER Adoption (Battery Storage and Solar Photovoltaic)

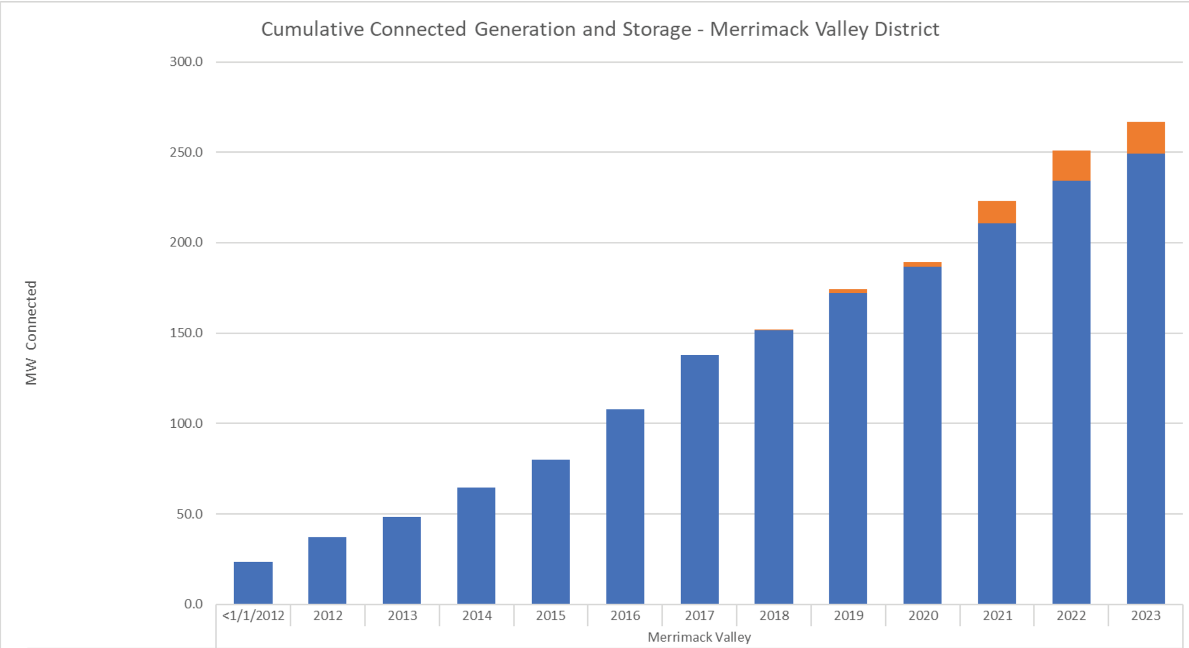
With a total of 266.6 MW of generation connected, the Merrimack Valley sub-region has relatively medium DER penetration. Connected DER is predominantly solar, representing 90% of the installed DER capacity in the sub-region.

Exhibit 4.39: Merrimack Valley Sub-Region DER Capacity Connected and In Queue

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	224.1	60.3
Battery	16.6	176.1
Hydro	0.4	16.7
Wind	0.7	0.0
Miscellaneous	24.9	3.1
Total	**266.6**	**256.2**

Note that in Exhibit 4.40 below, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.40: Merrimack Valley Sub-Region Cumulative Connected Generation and Storage



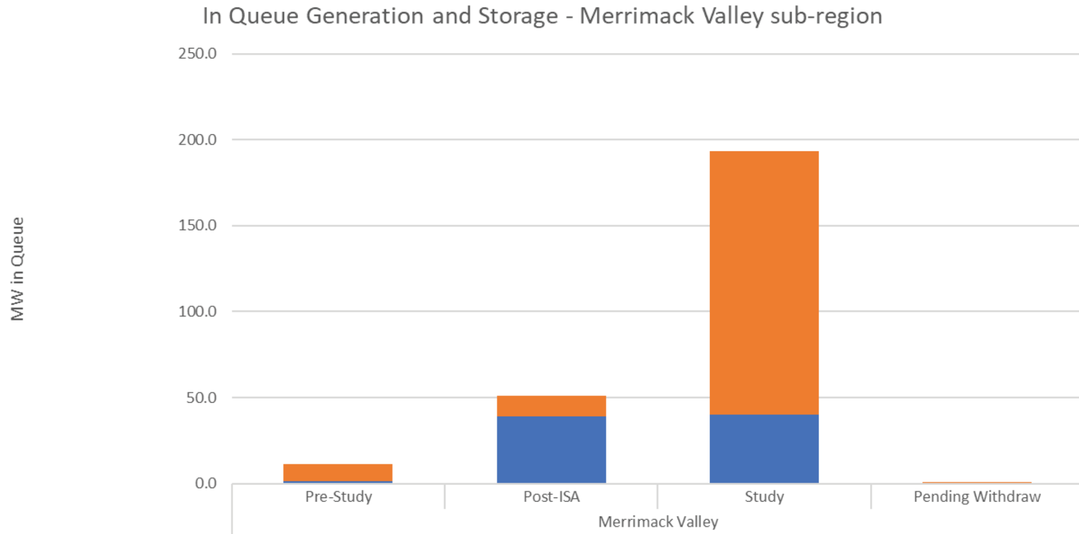
	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.1	2.8	12.5	16.6	17.2
Sum of Total Generator MW	23.3	37.2	48.2	64.4	80.0	107.8	138.0	151.6	172.2	186.5	210.7	234.2	249.4

Exhibit 4.40 above contains the current DER interconnection queue in the Merrimack Valley sub-region as of July 2023. As shown in the exhibit, recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 57% of the current queued DER capacity.

A large majority of the batteries are stand-alone, although some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.4.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.41: Merrimack Valley Sub-Region Pending DER Generation and Storage in Queue



	Pre-Study	Post-ISA	Study	Pending Withdraw
Sum of Total Storage MW	10.3	12.5	153.2	0.0
Sum of Total Generator MW	1.2	38.8	40.0	0.1

Between the 256.2MW of DER in the interconnection queue, and the 266.6MW already connected in the Merrimack Valley, the total for the area would be approximately 522.8MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a significant increase in the amount of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the Merrimack Valley sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas:

- Billerica
- Tewksbury
- Westford/Chelmsford

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation, process, and Provisional System Planning Provision methodology to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions

- Enabled electrification: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, to interconnect the 88 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of one substation transformer and approximately 10 miles of distribution line construction, at an estimated cost of $40M.

4.4.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

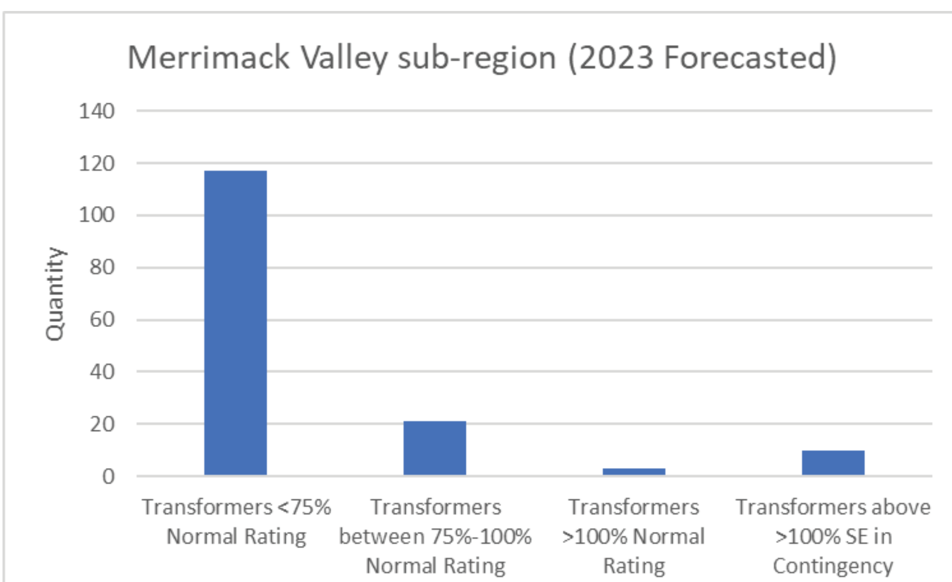
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in Sections 6.3, 6.11, and 9.3 and 9.6, the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Merrimack Valley region over 9,500 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 23 MW of load on the grid when the overall grid is at peak.

4.4.7 Capacity Deficiency

Exhibit 4.42 below summarizes the asset loading across the Merrimack Valley sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.42: Merrimack Valley Sub-Region 2023 Forecasted Transformer Loading Profile



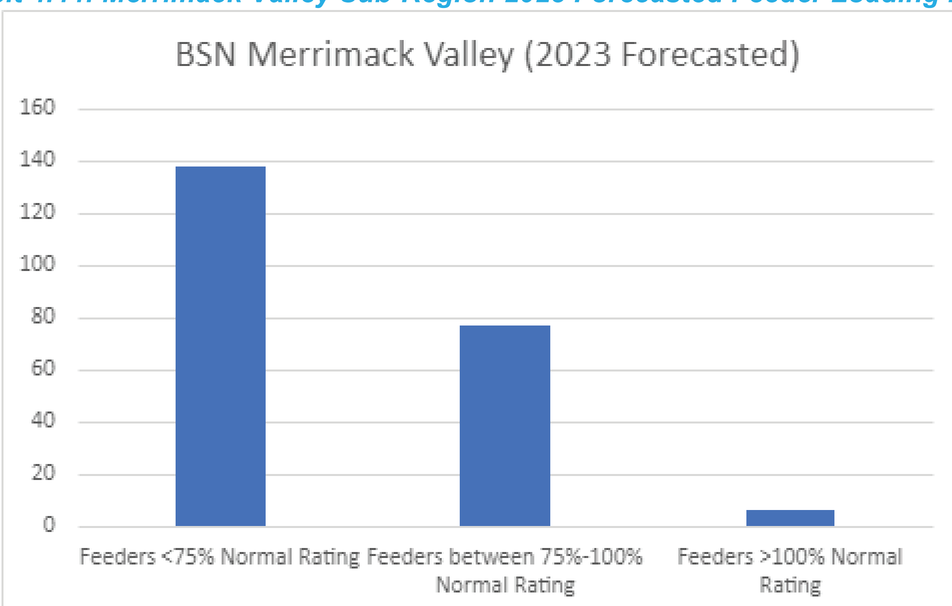
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.43: Merrimack Valley Sub-Region 2023 Forecasted Transformer capacity deficiencies

Study Area	Substation	Capacity Deficiency
Lawrence	NORTH LAWRENCE 6	Transformers > 100% Emergency Rating in Contingency
North Lowell	BOULEVARD 77	Transformers > 100% Emergency Rating in Contingency
Tewksbury	EAST TEWKSBURY 59	Transformers > 100% Emergency Rating in Contingency
North Andover	WEST ANDOVER 8	Transformers > 100% Emergency Rating in Contingency
Haverhill	WARD HILL 43	Transformer > 100% Normal Rating
Amesbury Newburyport	WEST NEWBURY 47	Transformer > 100% Normal Rating
North Andover	SOUTH UNION ST 61	Transformer > 100% Normal Rating

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.44: Merrimack Valley Sub-Region 2023 Forecasted Feeder Loading Profile



Six feeders in the Merrimack Valley sub-region have an identified existing capacity deficiency. These deficiencies are being monitored as anticipated spot loads come into service, and operational mitigations will manage the overloads as appropriate.

The Merrimack River cuts through much of this area and adding or modifying any distribution infrastructure that needs to cross the river must be carefully considered during solution development, as such crossings can add significant complexity to projects.

The Merrimack Valley sub-region includes 30 substations which step the voltage down from 23 kV to a mixture of 13 kV and 4.16 kV, some of which have contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

Much of the Merrimack Valley sub-region shares a border with New Hampshire, and in some cases distribution facilities from one jurisdiction are supplied from the neighboring utility. In such cases, infrastructure investments in these areas must consider Liberty Utilities as a critical stakeholder.

4.4.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases, and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is primarily driven by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important that that the Company remains diligent in improving the infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiencies and decarbonization). This type of modernization work will fit into core and Future Grid Plan work, depending on the project driver (asset condition or system capacity/load growth, respectively).

Exhibit 4.45 below shows the metalclad age profile in the Merrimack Valley sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.45: Merrimack Valley Sub-Region Metalclad Age Profile

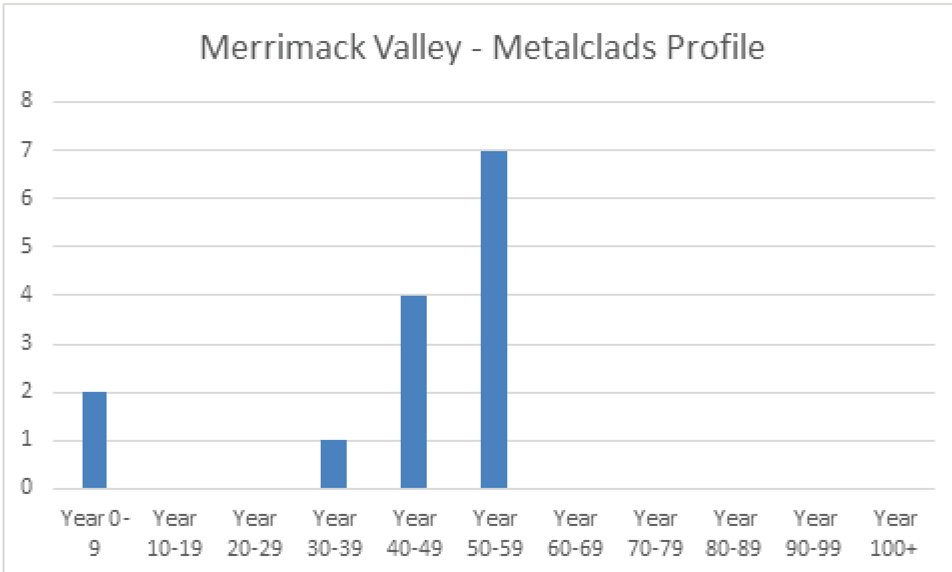


Exhibit 4.46 below shows the transformer age profile in the Merrimack Valley sub-region.

Exhibit 4.46: Merrimack Valley Sub-Region Substation Transformer Age Profile

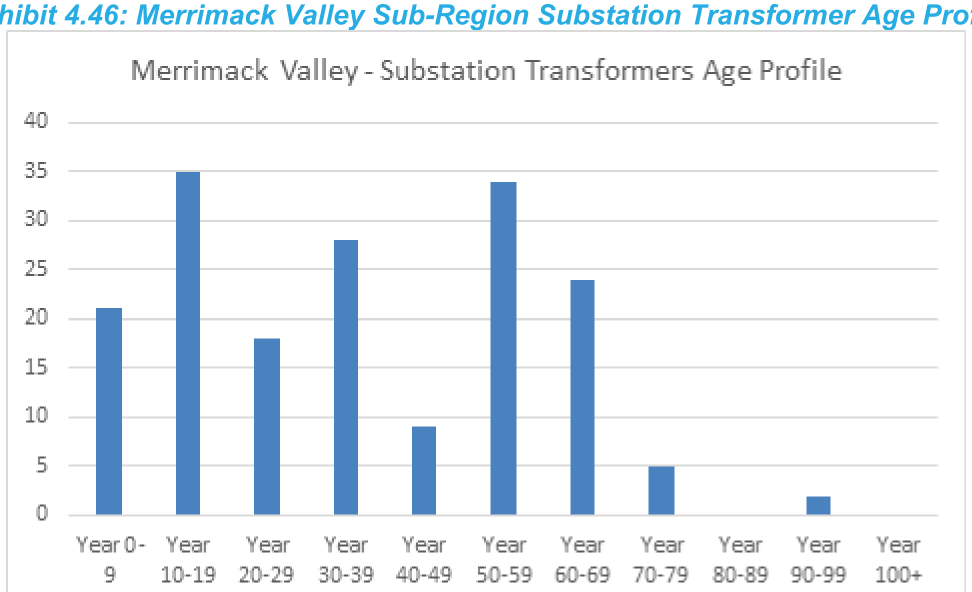


Exhibit 4.47 below shows the distribution pole age profile in the Merrimack Valley sub-region.

Exhibit 4.47: Merrimack Valley Sub-Region Distribution Pole Age Profile

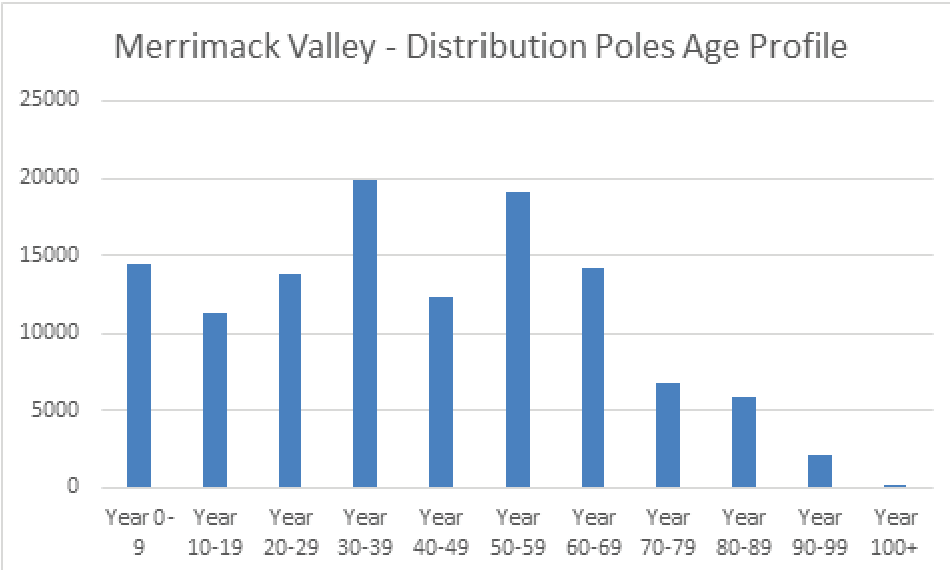
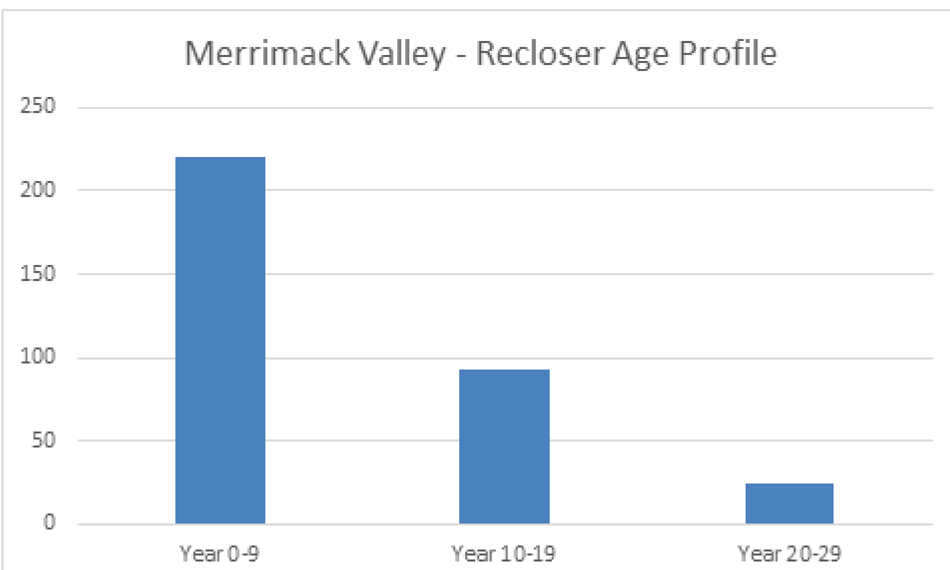


Exhibit 4.48 below shows the recloser age profile in the Merrimack Valley sub-region. Reclosers are further described in Section 4.3.8.

Exhibit 4.48: Merrimack Valley Sub-Region Recloser Age Profile



4.4.9 Reliability and Resilience

This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality

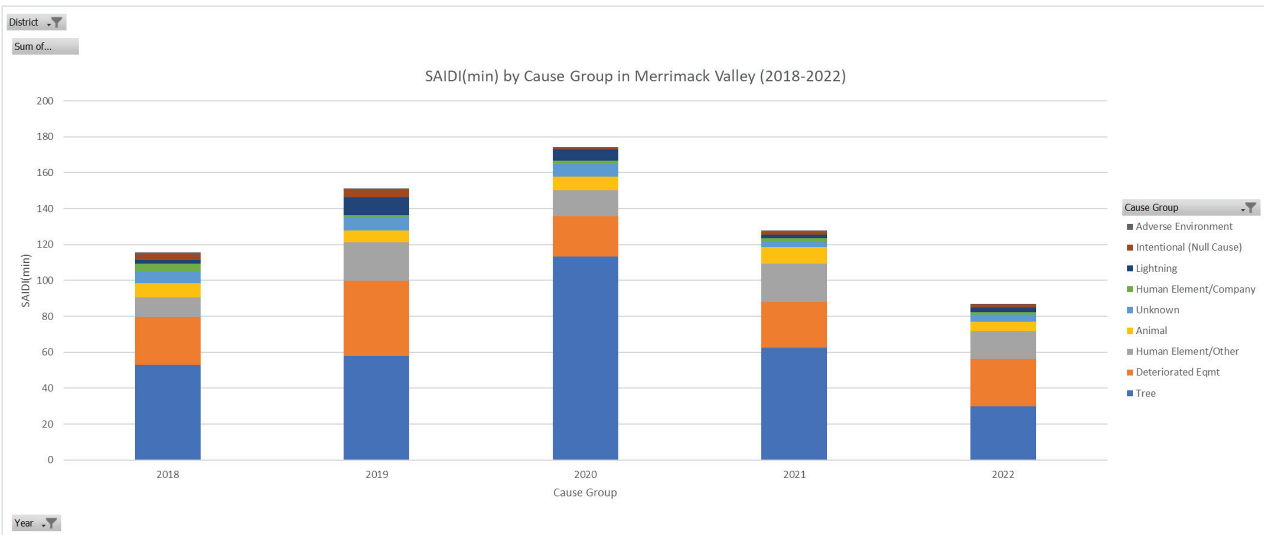
Guidelines.[20] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

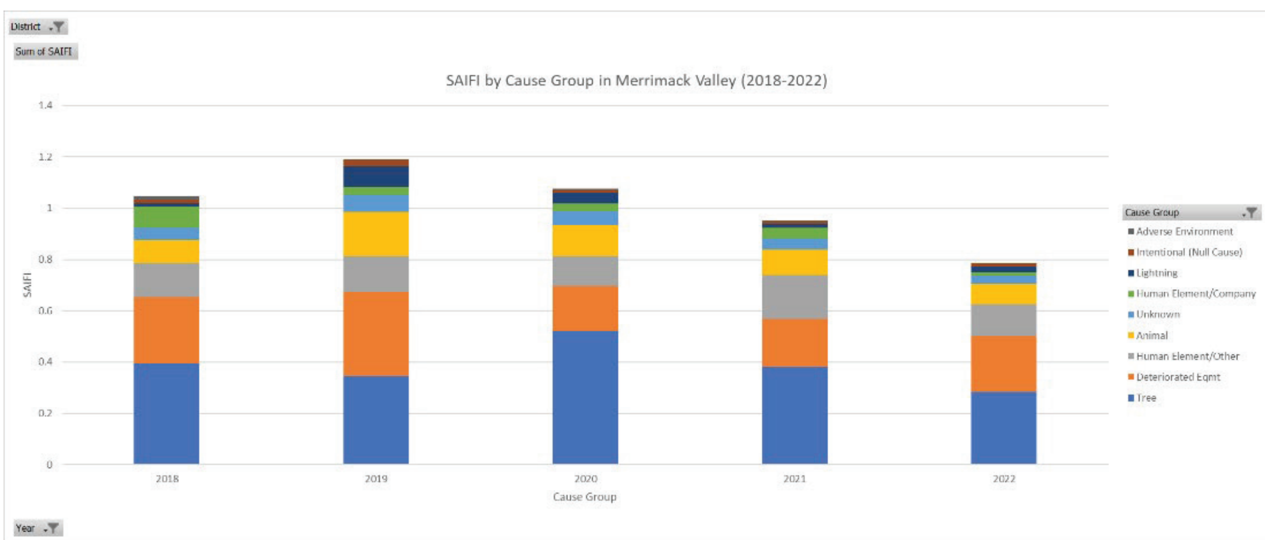
Refer to Section 4.3.9 for background on reliability metrics and performance.

Reliability Performance

Exhibit 4.49 below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

Exhibit 4.49: Merrimack Valley Sub-Region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance





[20] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, Merrimack Valley has been in the second quartile for frequency of outages (SAIFI) and has been in the first or second quartile for the past five years for duration (SAIDI).

SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
2nd Quartile	2nd Quartile	3rd Quartile	2nd Quartile	2nd Quartile

Sum of SAIDI Medium Quartile				
2018	2019	2020	2021	2022
2nd Quartile	2nd Quartile	2nd Quartile	2nd Quartile	1st Quartile

Refer to Section 4.3.9 for background on how reliability metrics are calculated.

Resiliency Performance

As described in section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated "all-in" SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with Environmental Justice Areas, as defined by the Commonwealth. The exhibits below show the Company's distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company's entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company's distribution substations.

Exhibit 4.50: Merrimack Valley Sub-Region Resiliency in EJCs as shown as SAIDI Substation Performance

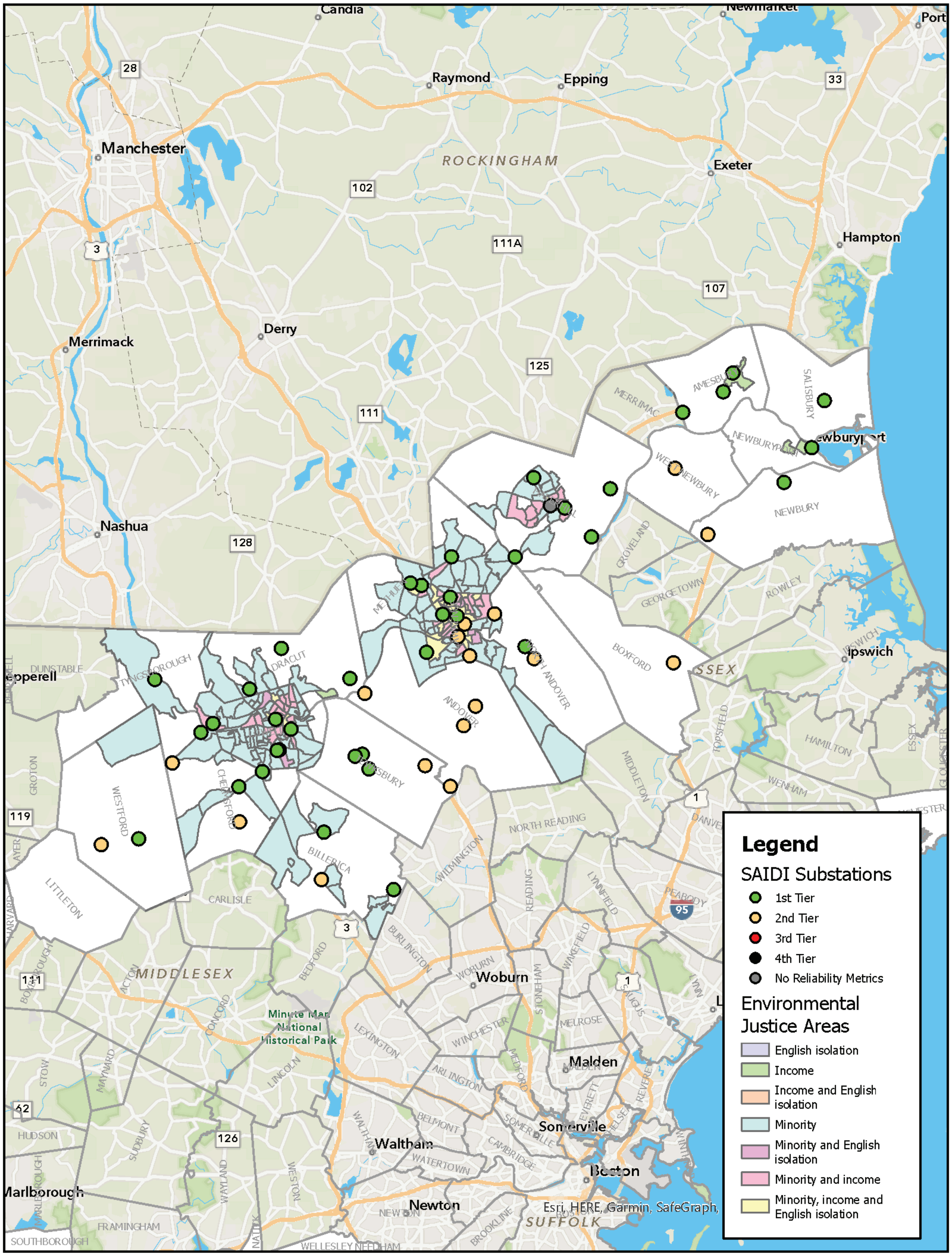
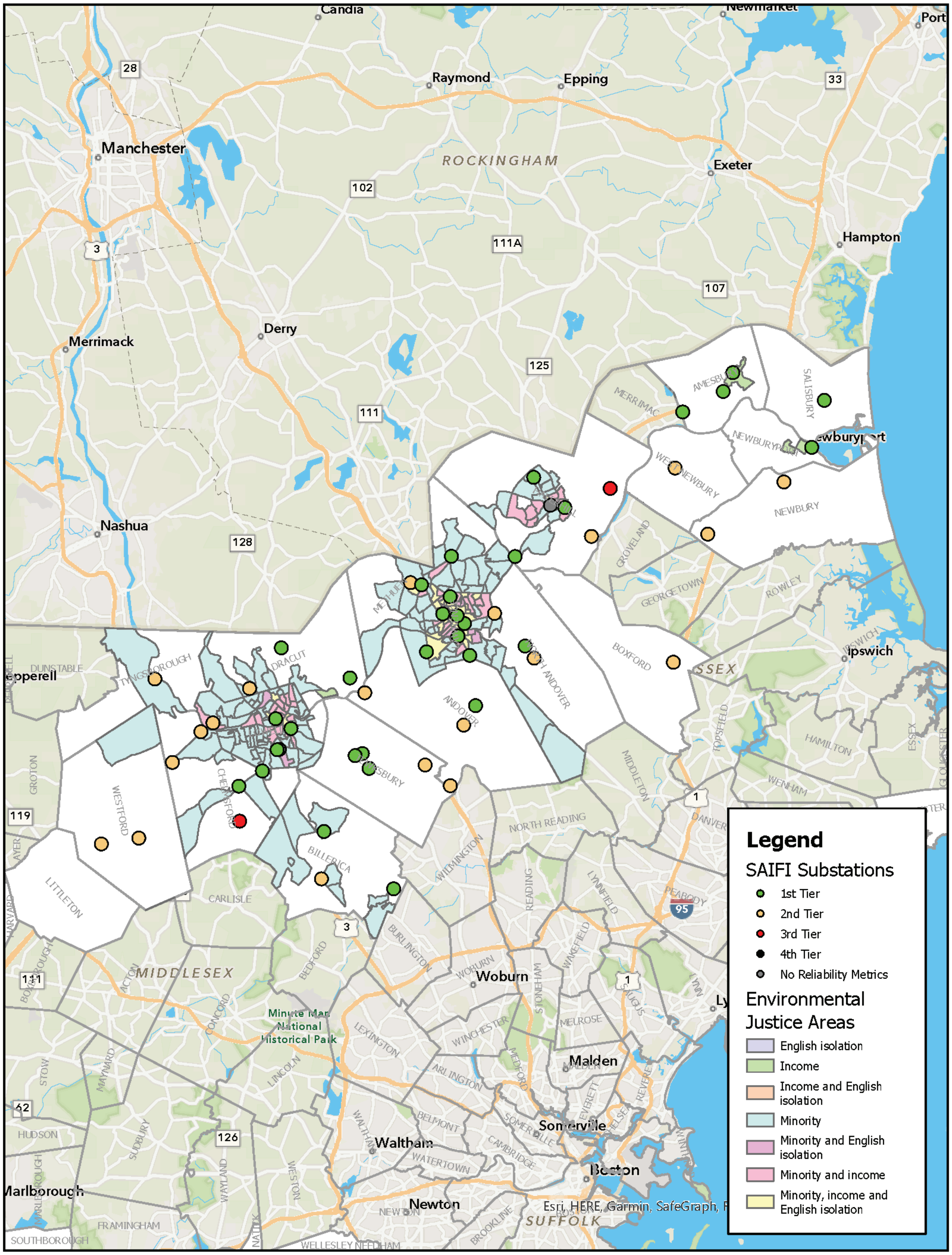


Exhibit 4.51: Merrimack Valley Sub-Region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.4.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the Energy EFSB review process is triggered to ensure the work is in compliance with State requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

Since Merrimack Valley is one of the more developed sub-regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure given the wetland mitigation requirements for permanently impacted land. Despite this generalization, each site presents different siting and environmental considerations.

4.5 North Shore Sub-Region

Nature of the area: The Northshore sub-region is predominantly urban with metropolitan core communities near Boston and sub-regional urban centers in Beverly, Gloucester, Lynn, Peabody, and Salem.

The Company's customers' energy needs, economic circumstances, and demographics in the North Shore sub-region vary greatly, which is why targeted and culturally competent community engagement is at the core of the Company's plan to help the Commonwealth achieve its goals.

Exhibit 4.52: North Shore Sub-Region Customers by The Numbers

Description	Value	Unit
Number of Substations	49	Count
Number of Feeders	319	Count
Total Length of Feeders	2,000	Miles
Total Peak Load Served	1,107	MW
Sub-region Area	174	Square Miles
Benefits of EE	1,286,916	MWh
Heat Pump Adoption	1,399	Count
Charging Ports Installed	390	Count
5-Year Residential Population Growth Projections	1.6%	Percent
5-Year Forecasted Load Growth	6.6%	Percent
Existing Connected Rooftop DER (< 25kW)	82	MW

Context of the region

The North Shore is a predominantly urban area which contains a highly integrated network. The North Shore sub-region has low levels of DER penetration in this area relative to other sub-regions due to the lack of large swaths of open space coupled with a network with limited capacity. Due to the dense population and proximity to Boston, the Company anticipates load to grow by approximately 6.6% in the North Shore region in the next five years. Additional details can be found in Section 5.

Below are some key characteristics of the North Shore sub-region which will drive future investment needs.

Exhibit 4.53: North Shore Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
Most of the distribution circuits are a combination of 5 kV (which operate at voltages of 4.16 kV and 2.4 kV) and 15 kV class circuits (which operate at voltages of 13.2 kV or 13.8 kV). There are eighty circuits that operate at 4.16 kV which are supplied from substations that step down the voltage of 23 kV & 13 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower. This 4.16 kV infrastructure is prevalent throughout the North Shore, particularly in urban centers.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the Commonwealth. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
The 23 kV class subtransmission circuits act both as supplies to substations and to serve mostly larger load customers.	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both upgrading the substation and extending transmission facilities into these areas to meet the projected load growth.
The Lynn Network no longer meets the needs of the modern distribution system in this area, presenting challenges to provide service to new load and DER customers in areas served by the Network.	The Company has identified the need to contract and eventually eliminate the Lynn Network, replacing it with a radial system with feeder ties more suited to today’s needs.
There is extensive underground construction in urban areas.	As capacity limitations are reached on existing underground cables, the ability to increase the size of those cables or install new cables for additional capacity without doing costly civil work to install new duct banks is very limited. This contributes to high-cost distribution line projects when the Company needs to increase the capacity in these areas.

4.5.1 Maps

The North Shore sub-region consists of 19 municipalities and comprises the study areas below.

Exhibit 4.54: North Shore Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Cape Ann	Beverly, Essex, Gloucester, Hamilton, Manchester, Rockport, Wenham
2	Beverly	Beverly, Hamilton, Wenham
3	Everett/Malden/Medford	Everett, Malden, Medford
4	Lynn	Lynn, Nahant, Salem, Saugus, Swampscott
5	Melrose/Saugus	Everett, Lynn, Malden, Medford, Melrose, Revere, Saugus
6	Revere/Winthrop	Revere, Winthrop
7	Salem/Swampscott	Salem, Swampscott
8	Topsfield	Topsfield

Exhibit 4.55 below shows the substation locations within the North Shore sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically. Many of the locations of substations in the North Shore sub-region were driven by residential and commercial property development. Strong economic development activity has continued in these areas due to their proximity to public transit systems and available labor pools, as well as builder interest in unused or limited use waterfront parcels for mixed-use development.

Exhibit 4.55: North Shore Sub-Region Substation Locations and Study Areas

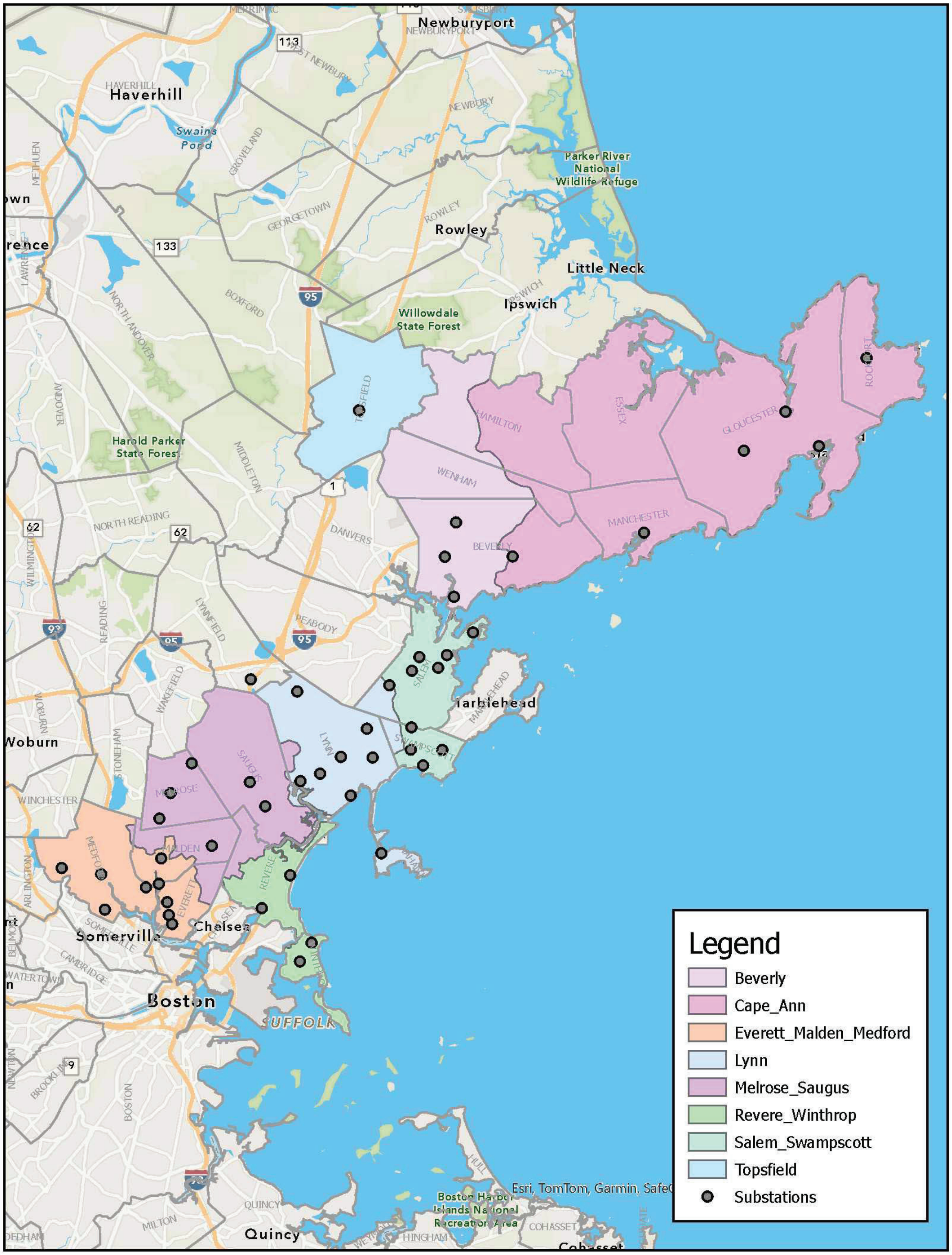
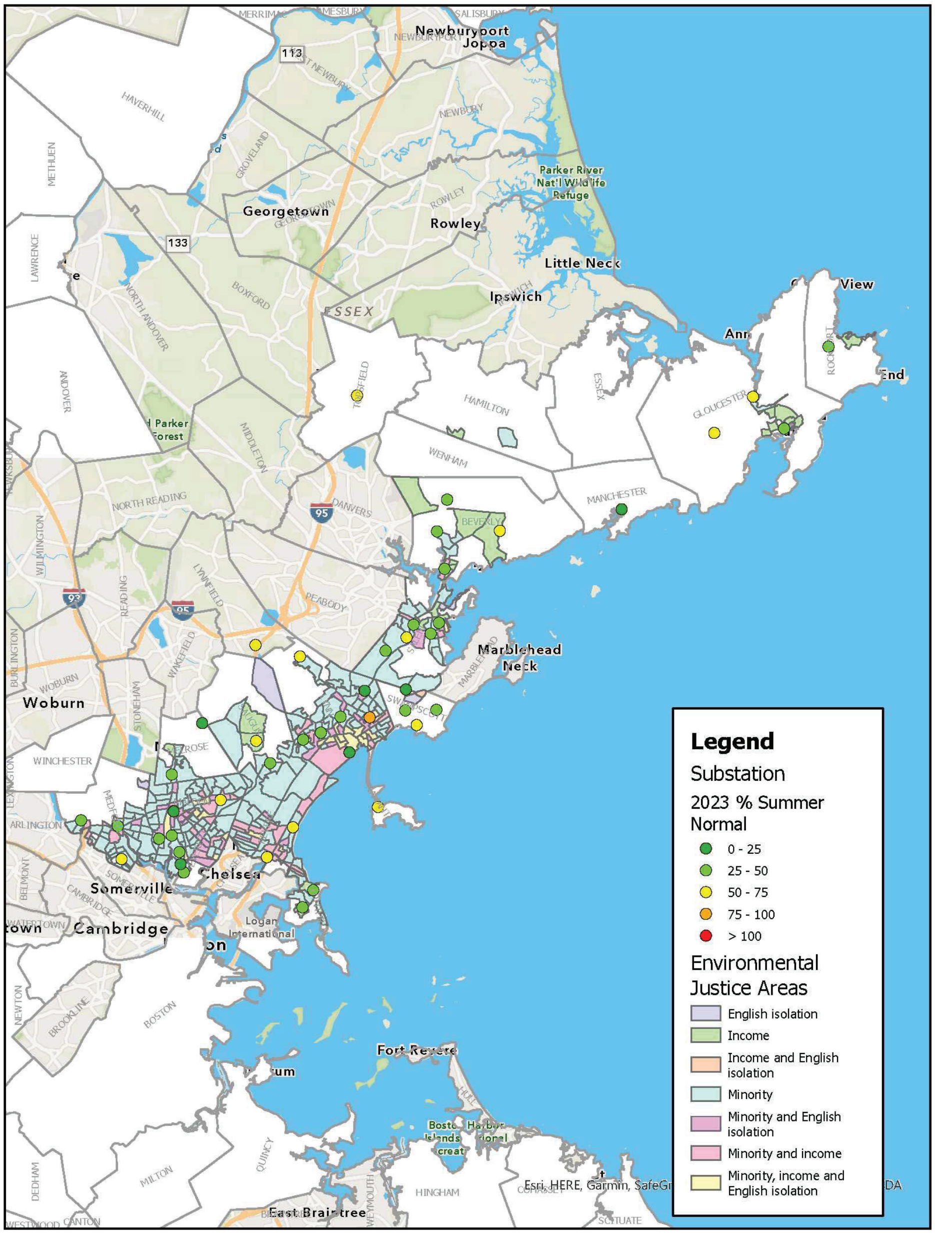


Exhibit 4.56 displays projected 2023 summer normal loading at each substation in the North Shore region.[21] While no transformers were projected to be loaded over their 100% of summer normal ratings, there is one loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

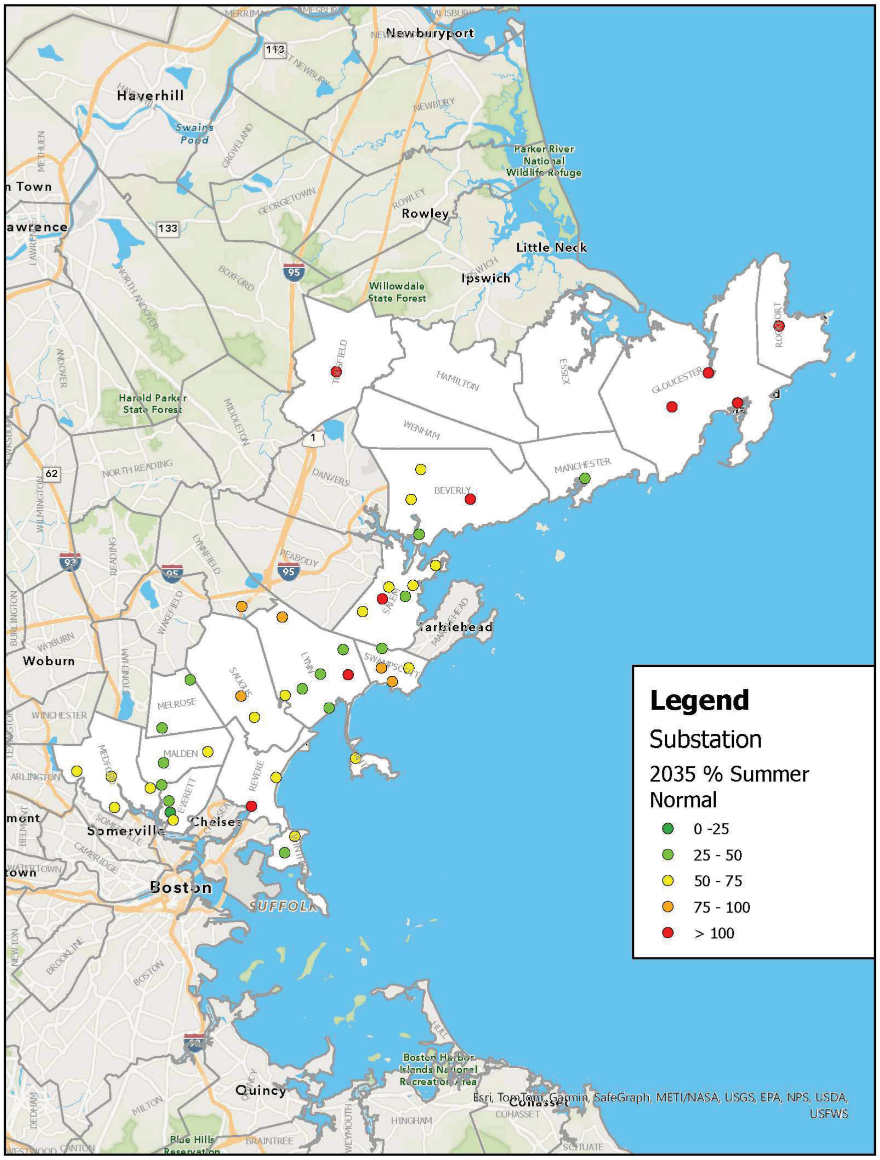
Exhibit 4.56: North Shore Sub-Region Substation Transformer Loading in 2023



[21] The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Figure 4.57 below shows where the projected overloads will happen.

Exhibit 4.57: North Shore Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.5.2 Customer Demographics

Exhibit 4.58: North Shore Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts)	**255,067**	-
Residential	223,379	88%
Residential – Low Income Rate Participants	*26,892*	-
Business, Commercial, Municipal, or University	31,688	12%

The Company serves a total of 255,067 customers (defined by individual accounts, not the number of people served) – in the North Shore sub-region. Approximately 88% (223,379) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

In addition to the Mass Save programs, which have benefited customers in the North Shore sub-region, 24 municipalities statewide have been identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans, the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the North Shore sub-region are Everett, Lynn, Malden, Revere, and Saugus.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing. Please refer to the Appendix for those drafts.

Below please see Exhibit 4.59 which overlays the Commonwealth EJC map with the Company's current substations.[22]

[22] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map.

Exhibit 4.59: North Shore Sub-Region Substation Locations in Relation to the Commonwealth's EJCs

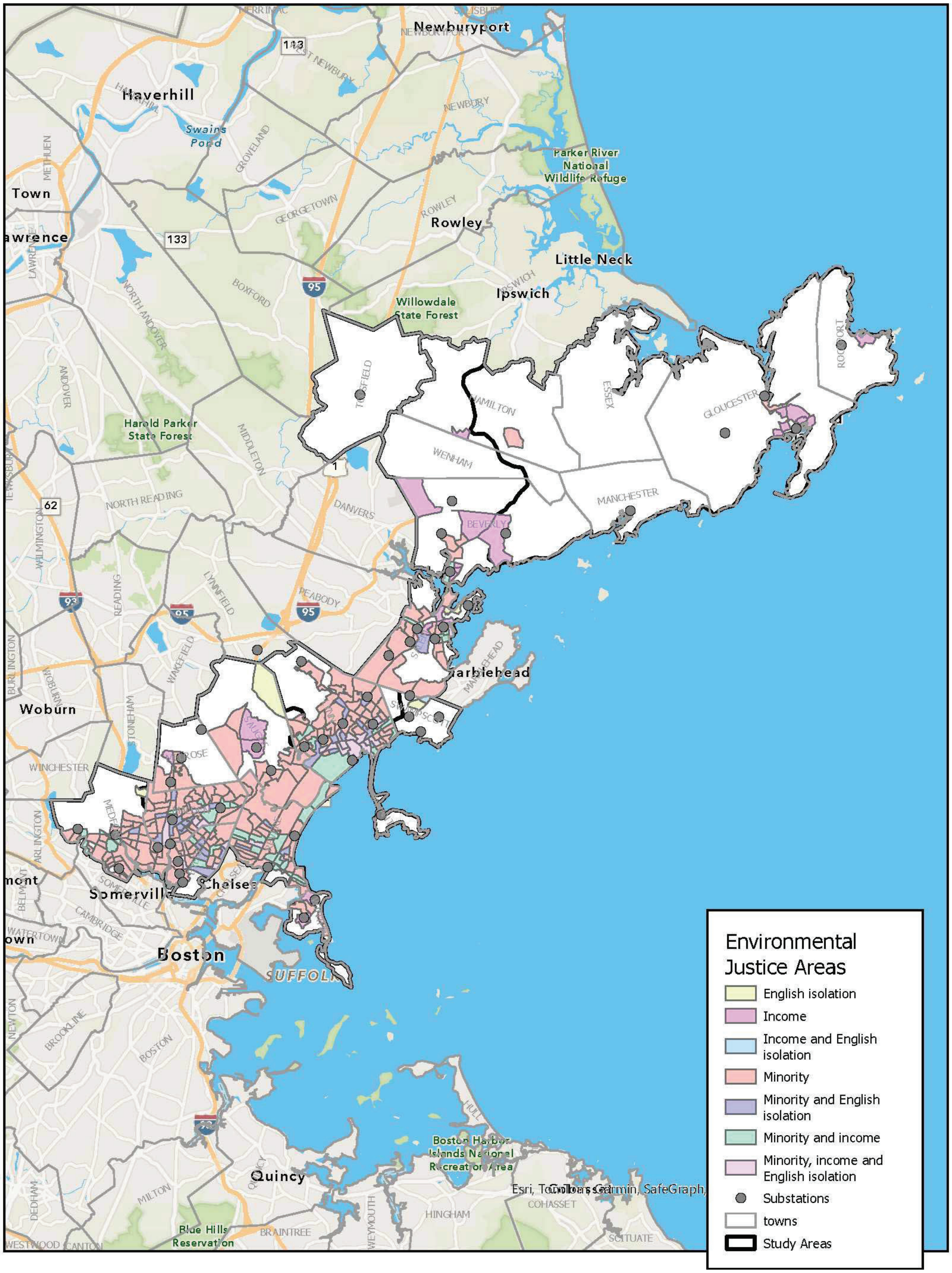


Exhibit 4.59 highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase as well. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all of the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits for all. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

4.5.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the North Shore sub-region, five communities (Beverly, Medford, Melrose, Salem, and Swampscott) have completed decarbonization plans, and 18 are designated as green communities. Four of the communities, in partnership with the Company, have completed a SEMP. The region is currently engaging with the MMA Economic Development Planning Council to develop a comprehensive strategy; however, understood concerns include climate resilience and flood mitigation. Additionally, the region aspires to foster increased commercial development opportunities and promote affordable housing.

4.5.4 Electrification Growth

Heat Electrification - The North Shore region has moderate heat pump adoption among the six regions with about 1,000 units adopted by the end of 2022.

Transport Electrification – There has been significant growth in the LDEV sales in the North Shore sub-region with about 5,500 vehicles as of the end of 2022, making the North Shore the sub-region with the highest EV count. However, the total number of MHDEVs is less than 10, indicating very low penetration at present, like other sub-regions. Since 2019, the Company has installed 390 EV charging ports via their phase I and phase II EV charging programs in the North Shore region.

4.5.5 DER Adoption (Battery Storage and Solar Photovoltaic)

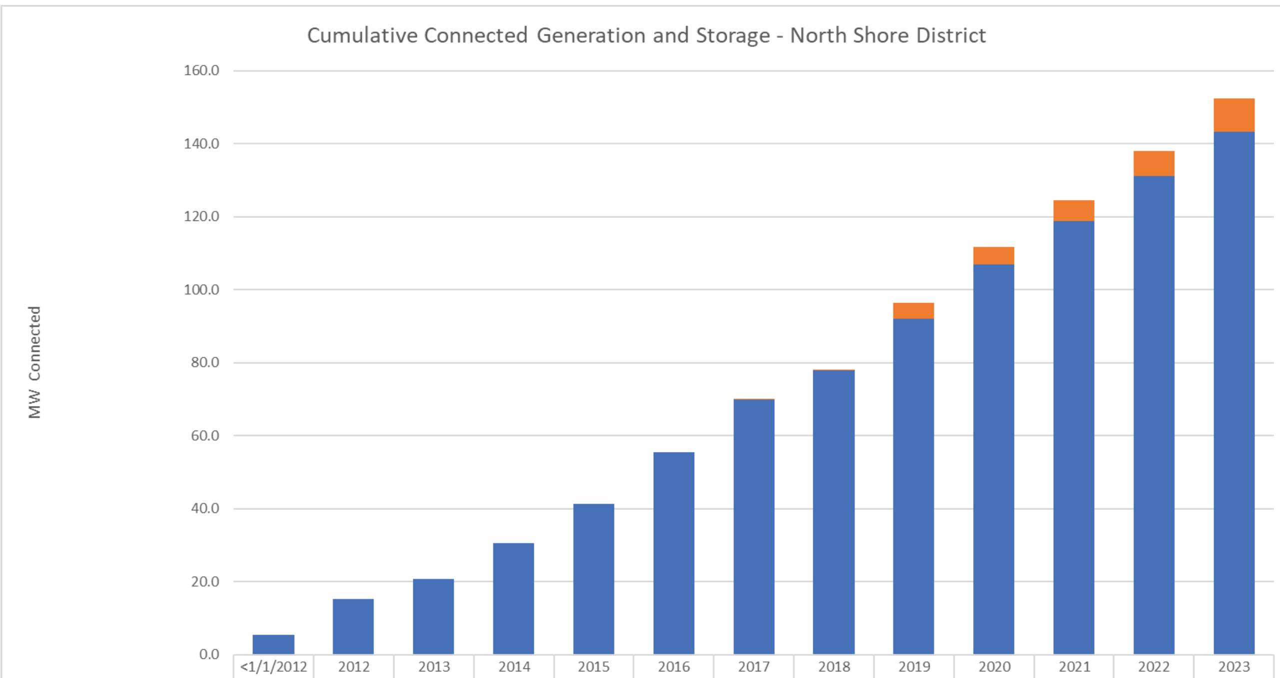
With a total of 152.2 MW of generation connected, the North Shore sub-region has relatively low DER penetration. Somewhat similar to the Merrimack Valley sub-region, this low penetration has to do with the limited capacity on the network coupled with the lack of abundant open space to install large facilities. Connected DER is predominantly solar, representing 87% of the installed DER capacity in the sub-region.

Exhibit 4.60: North Shore Sub-Region DER Capacity Connected and In Queue

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	121.6	16.13
Battery	5.0	59.4
Hydro	0.0	0.0
Wind	7.3	0.0
Miscellaneous	18.3	2.0
Total	**152.2**	**77.5**

The past decade has seen tremendous growth in DER connections in the North Shore sub-region. Note that in the exhibits below, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.61: North Shore sub-region Cumulative Connected Generation and Storage



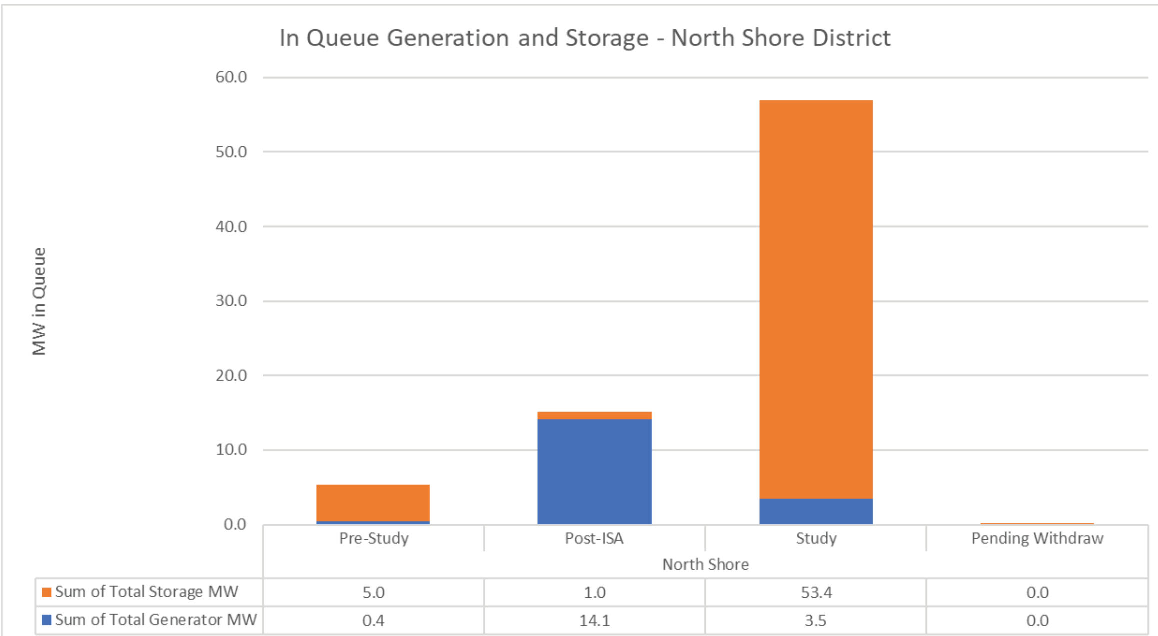
	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	4.5	4.8	5.8	6.8	9.1
Sum of Total Generator MW	5.4	15.2	20.6	30.6	41.2	55.5	69.8	77.8	92.0	106.9	118.7	131.2	143.2

Exhibit 4.62 contains visibility of the current DER interconnection queue in the North Shore sub-region. As shown in the exhibit, recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 73% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.5.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.62: North Shore Sub-Region Pending DER Generation and Storage In Queue



Combining the 77.5MW of DER in the interconnection queue, and the 152.2MW already connected in the North Shore sub-region, the total for the area would be 229.7MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the North Shore sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas:[3]

- Beverly

The proposed DER and system modifications required for the proposed groups have been included in the base case for this Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described in will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the CIP cost allocation methodology, process, and Provisional System Planning Provision to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:

    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provides thermal capacity beyond the planning horizon and supports some loading projects out to 2050.
- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 25 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of three substation transformers and approximately four miles of distribution line construction, at an estimated cost of $70M.

4.5.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

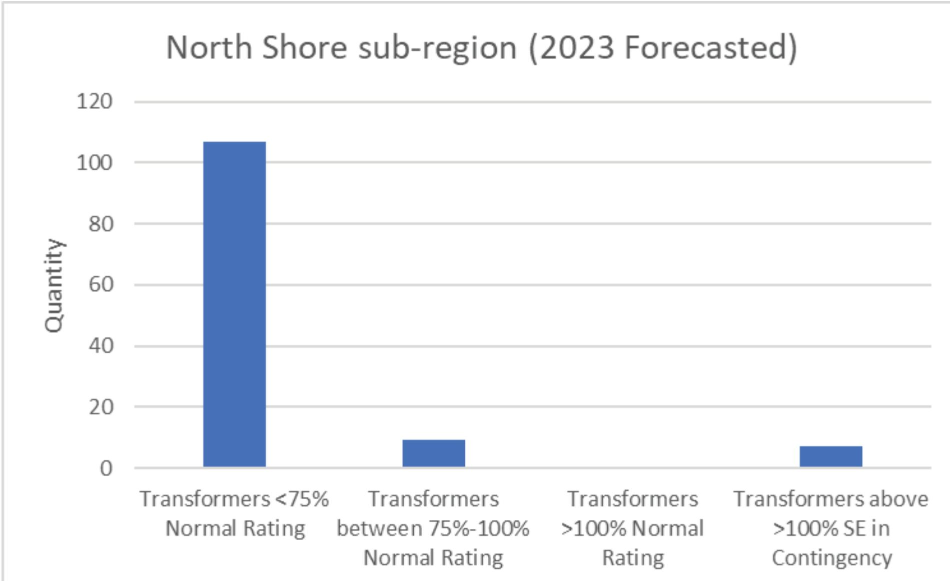
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in Sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the North Shore region over 6,000 customers currently participate in ConnectedSolutions DR program and help to reduce approximately 28 MW of load on the grid when the overall grid is at peak. This has helped to delay investments and maximize the utilization of the current network.

4.5.7 Capacity Deficiency

The graphs below summarize the asset loading across the North Shore sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.63: North Shore Sub-Region 2023 Forecasted Transformer Loading Profile



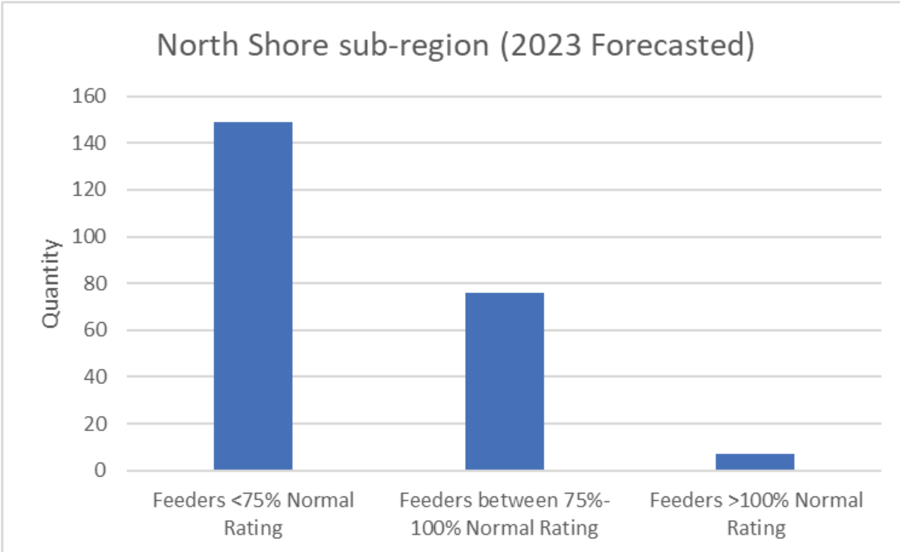
Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.64: North Shore sub-region 2023 Forecasted Transformer Capacity Deficiencies

Study Area	Substation	Capacity Deficiency
Cape Ann	Riverdale 52	Transformers > 100% Emergency Rating in Contingency
Revere Winthrop	Revere 7	Transformers > 100% Emergency Rating in Contingency
Cape Ann	East Beverly 51	Transformers > 100% Emergency Rating in Contingency
Salem Swampscott	West Salem 29	Transformers > 100% Emergency Rating in Contingency
Melrose Saugus	Maplewood 16	Transformers > 100% Emergency Rating in Contingency

There are operational protocols that go into effect to manage the risk of overloading of transformers upon a contingency event (e.g., the loss of a neighboring transformer).

Exhibit 4.65: North Shore Sub-Region 2023 Forecasted Feeder Loading Profile



Seven feeders in the North Shore sub-region have an identified existing capacity deficiency; these deficiencies are being monitored as anticipated spot loads come into service, and operational mitigations will manage the overloads as appropriate.

Much of the North Shore sub-region borders the ocean, and geographical constraints can complicate solution development in this area. The Cape Ann area is currently served by a mix of 34.5 kV and 23 kV subtransmission lines, since transmission does not extend any further east than Beverly. These lower voltage subtransmission lines have less load-serving capacity than higher voltage transmission lines would be capable of providing to the area.

The North Shore sub-region includes 28 substations which step the voltage down from 34.5kV or 23 kV to a mixture of 13 kV and 4.16 kV, some of which have contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

The North Shore sub-region features 147 circuits that are 4.16 kV, which are mainly located in urban settings. These circuits have limited capacity and are primarily located in urban areas with significant amounts of underground infrastructure. Converting underground facilities to a higher voltage to achieve greater capacity can come at significant cost.

4.5.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases, and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria on their asset health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the Company's grid and/or substations, existing equipment may need to be modified or replaced in order to digitize the Company's methods. It is important that the Company remains diligent in improving infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiencies and decarbonization).

Exhibit 4.66 shows the metal clad age profile in the North Shore sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.66: North Shore Sub-Region Metalclad Age Profile

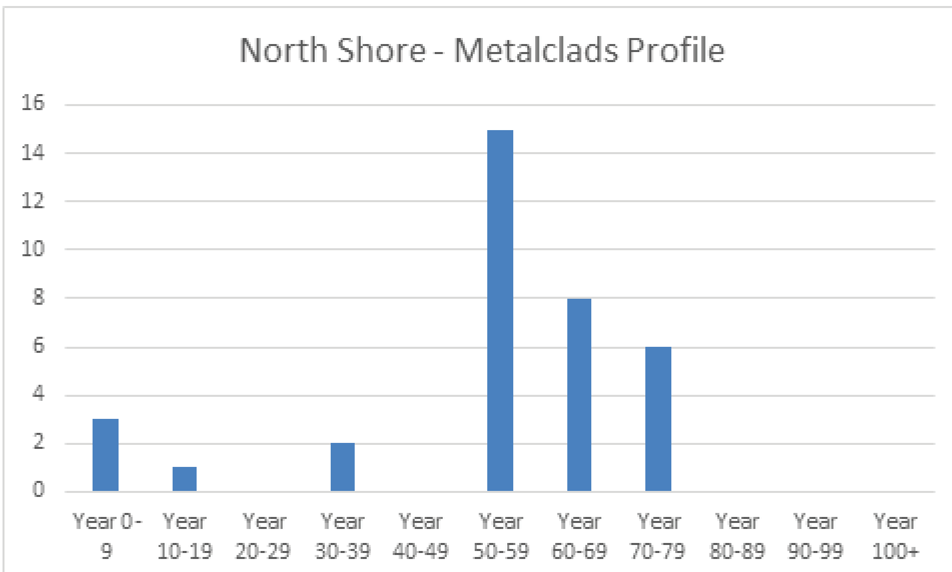


Exhibit 4.67 shows the substation transformer age profile in the North Shore sub-region.

Exhibit 4.67: North Shore Sub-Region Substation Transformer Age Profile

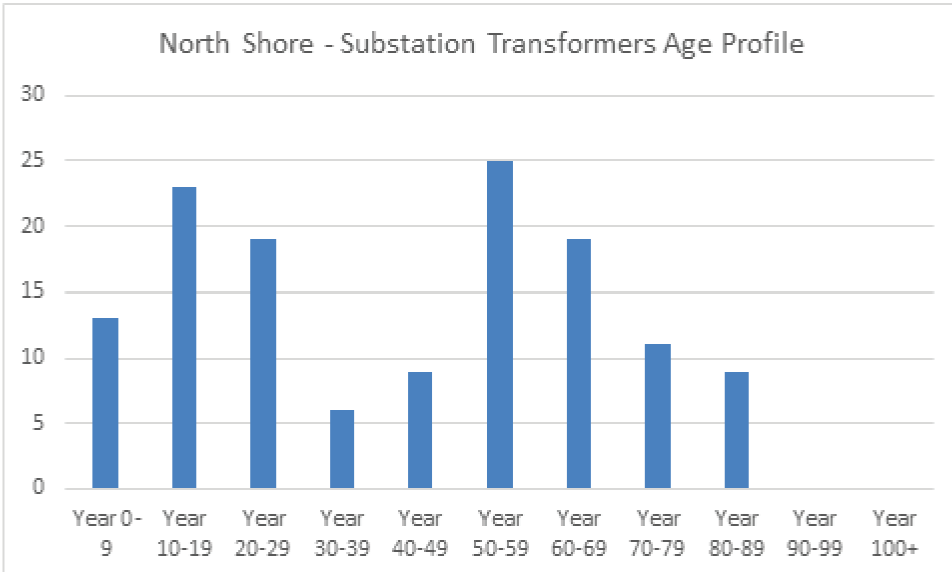


Exhibit 4.68 shows the distribution pole age profile in the North Shore sub-region.

Exhibit 4.68: North Shore Sub-Region Distribution Pole Age Profile

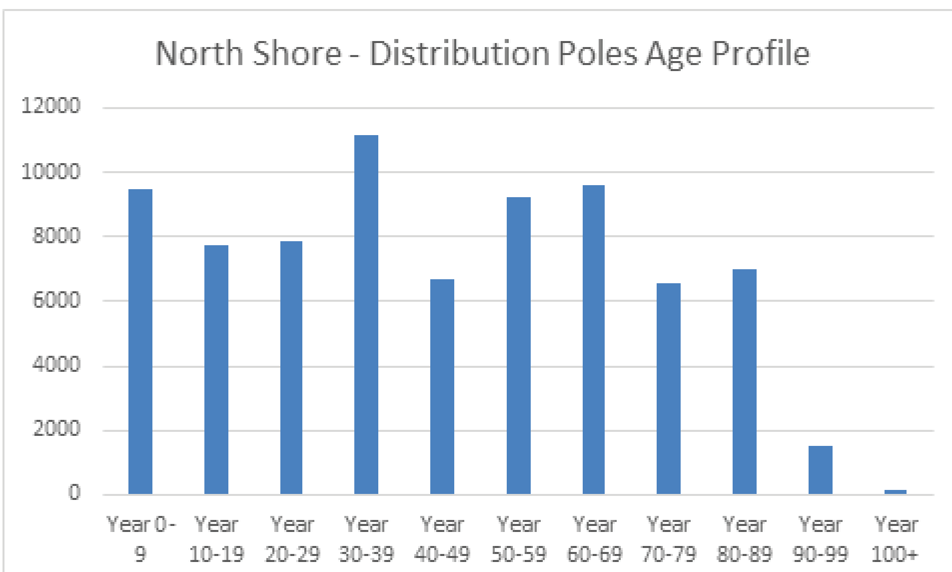
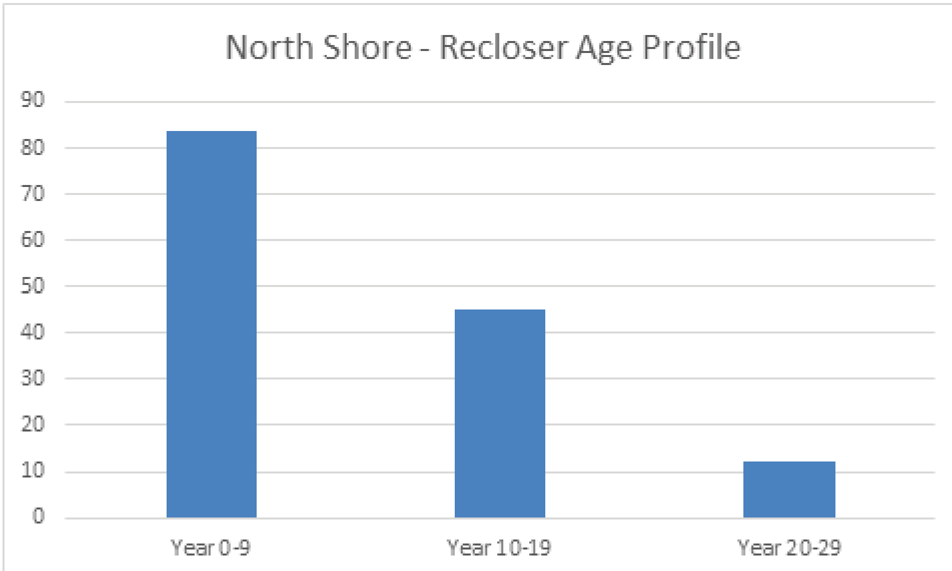


Exhibit 4.69 shows the recloser age profile in the North Shore sub-region.

Exhibit 4.69: North Shore Sub-Region Recloser Age Profile



4.5.9 Reliability and Resilience

This section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality Guidelines.[23] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

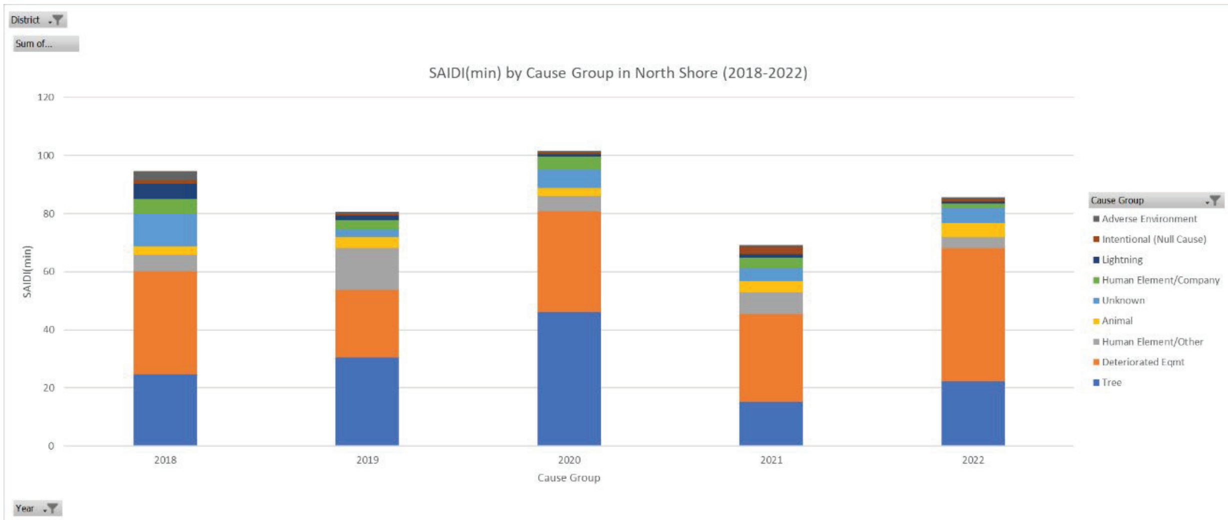
Refer to Section 4.3.9 for background on reliability metrics and performance.

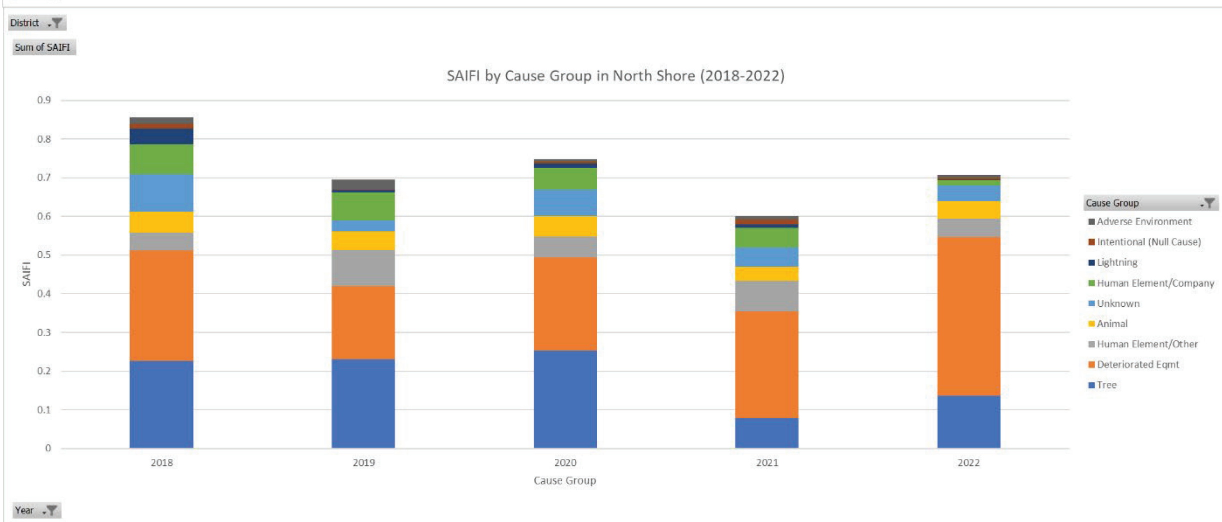
Reliability performance

The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events and deteriorating equipment (due to a larger portion of undergrounded distribution in this region) caused the majority of outages across this sub-region, in terms of duration and frequency.

[23] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

Exhibit 4.70: North Shore Sub-Region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance





The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for the last four years, North Shore has been in the first quartile for frequency of outages (SAIFI) and has been in the first quartile for the past four years for duration (SAIDI).

SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
2nd Quartile	1st Quartile	1st Quartile	1st Quartile	1st Quartile

Sum of SAIDI Medium Quartile				
2018	2019	2020	2021	2022
2nd Quartile	1st Quartile	1st Quartile	1st Quartile	1st Quartile

Refer to section 4.3.9 for background on how reliability metrics are calculated.

Resiliency performance

As described in Section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated "all-in" SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in Section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs, as defined by the Commonwealth. The exhibits below show the Company's distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company's entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability.

Exhibit 4.71: North Shore Sub-Region Resiliency in EJCs as shown as SAIDI Substation Performance

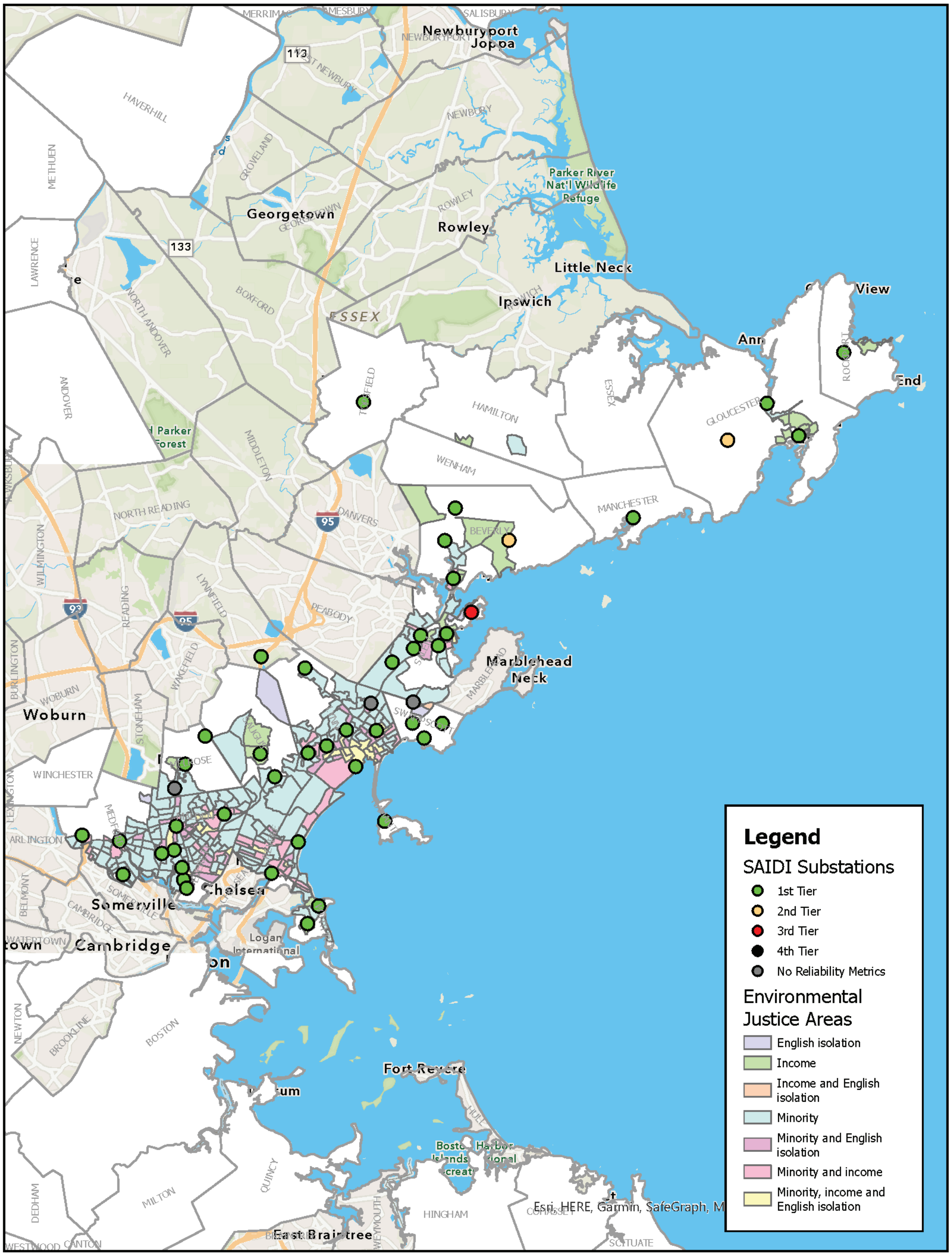
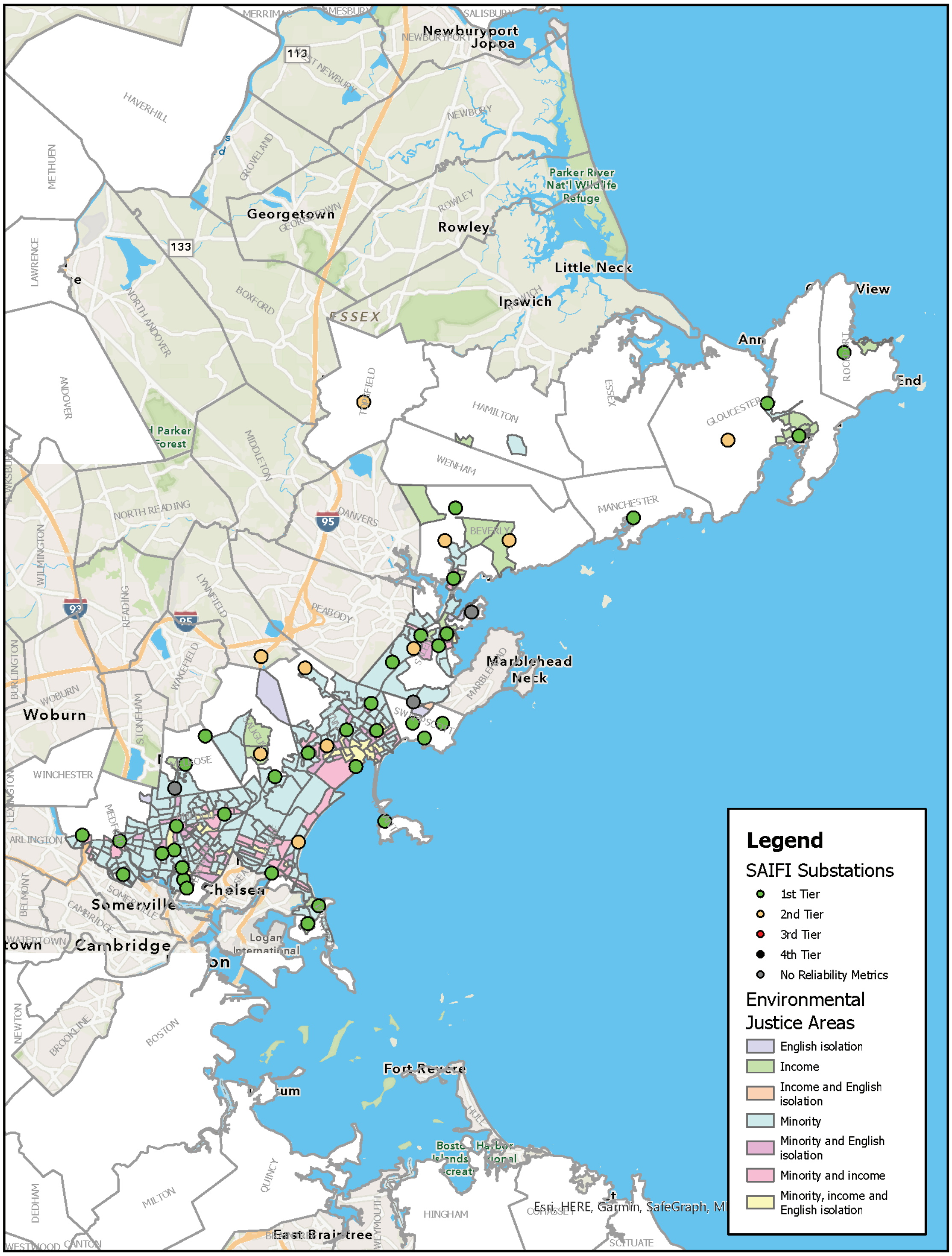


Exhibit 4.72: North Shore Sub-Region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was a particularly bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.5.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with state requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

Since the North Shore sub-region is one of the more developed regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure. Each site presents different siting and environmental considerations, especially given the wetland mitigation requirements for permanently impacted land.

4.6 Southeast Sub-Region

Nature of the area: The Southeast sub-region is predominantly suburban with urban centers in Milford, Attleboro, Fall River, and Somerset.

Exhibit 4.73: Southeast Sub-Region Customers by the Numbers

Description	Value	Unit
Number of Substations	43	Count
Number of Feeders	178	Count
Total Length of Feeders	3,600	Miles
Total Peak Load Served	1,029	MW
Sub-region Area	610	Square Miles
Benefits of EE	1,169,519	MWh
Heat Pump Adoption	3,300	Count
Charging Ports Installed	390	Count
5- Year Residential Population Growth Projections	2.2%	Percent
5- Year Forecasted Load Growth	6.7%	Percent
Existing Connected Rooftop DER (< 25kW)	110	MW

Context of the region

The Southeast sub-region includes a variety of dense areas which has resulted in a highly integrated network and also rural areas which have a more radial network. There is a high level of DERs penetration in this area relative to all other sub-regions due to the large amount of open space coupled with more robust distribution infrastructure as compared to the western area of the Commonwealth. Due to the economic development and growing suburban areas, an approximate 6.7% load growth is expected in the Southeast sub-region in the next five years. Additional detail can be found in Section 5.

Below are some key characteristics of the Southeast sub-region which will drive future investment needs.

Exhibit 4.74: Southeast Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. There are 20 circuits that operate at 4.16 kV and are supplied from substations that step down the voltage of 13 kV or 23 kV to supply customers. Lower voltages such as 4.16 kV were used more commonly in the past when loads were lower.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the Commonwealth. Voltage conversions can be costly and complex projects, requiring widescale replacement or upgrade of significant amounts of both distribution line and substation facilities.
The 23 kV class subtransmission circuits in the area act both as supplies to substations and to serve mostly larger load customers	Subtransmission circuits have less capacity than transmission circuits; therefore, load growth on subtransmission-supplied substations can sometimes be limited by the subtransmission feeder supplying it. As a result, the Company will need to invest in both the substation and extend transmission facilities into these areas to meet the projected load growth.

4.6.1 Maps

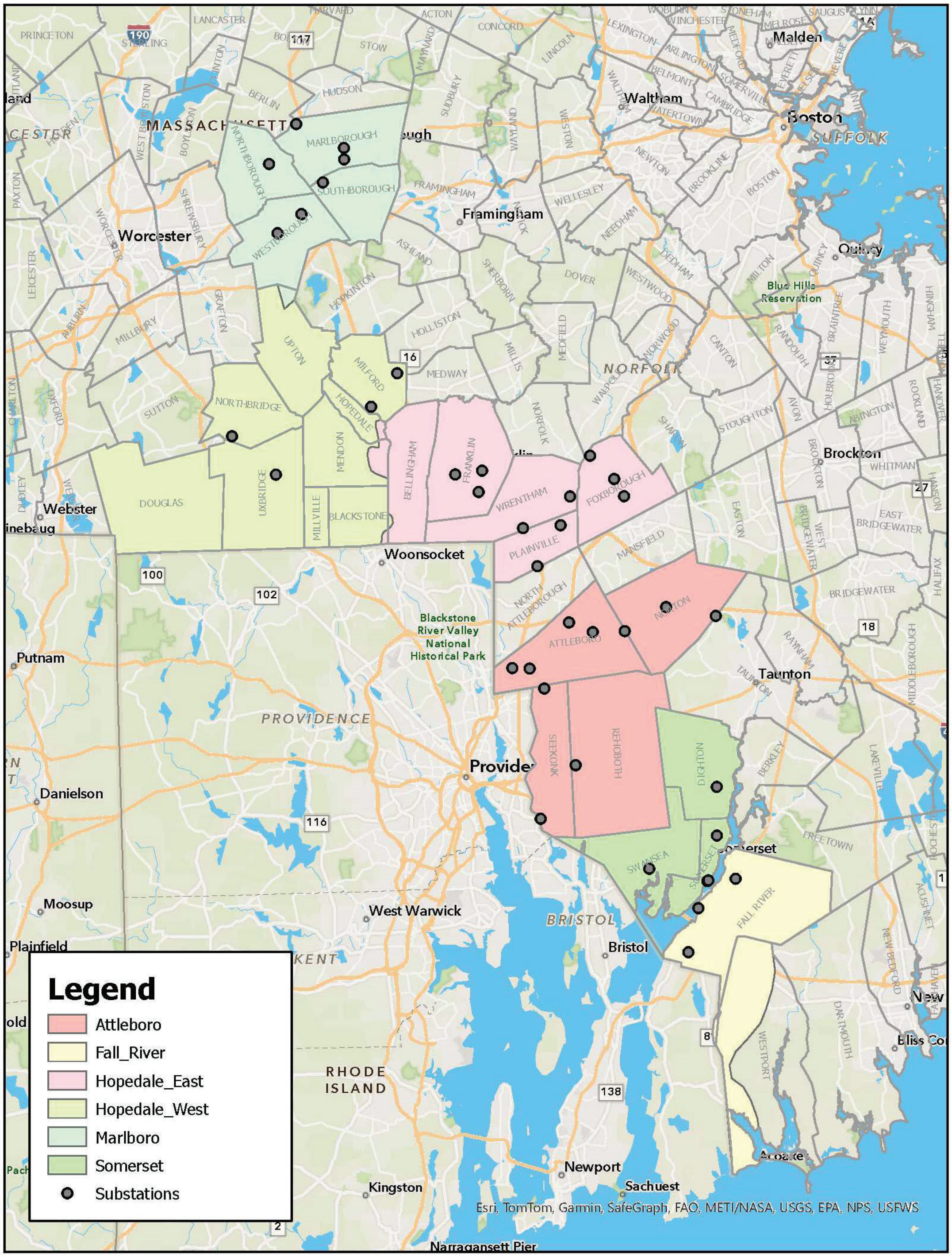
The Southeast sub-region consists of 32 municipalities and comprises the study areas below:

Exhibit 4.75: Southeast Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Attleboro	Attleboro, Norton, Rehoboth, Seekonk
2	Fall River	Fall River, Westport
3	Hopedale East	Bellingham, Blackstone, Foxborough, Franklin, Hopedale, Mendon, Plainville, Wrentham
4	Hopedale West	Bellingham, Blackstone, Douglas, Hopedale, Mendon, Milford, Millville, Northbridge, Upton, Uxbridge
5	Marlboro	Marlborough, Northborough, Southborough, Upton, Westborough
6	Somerset	Dighton, Somerset, Swansea

Exhibit 4.76 shows the substation locations within the Central sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.76: Southeast Sub-Region Substation Locations and Study Areas[24]



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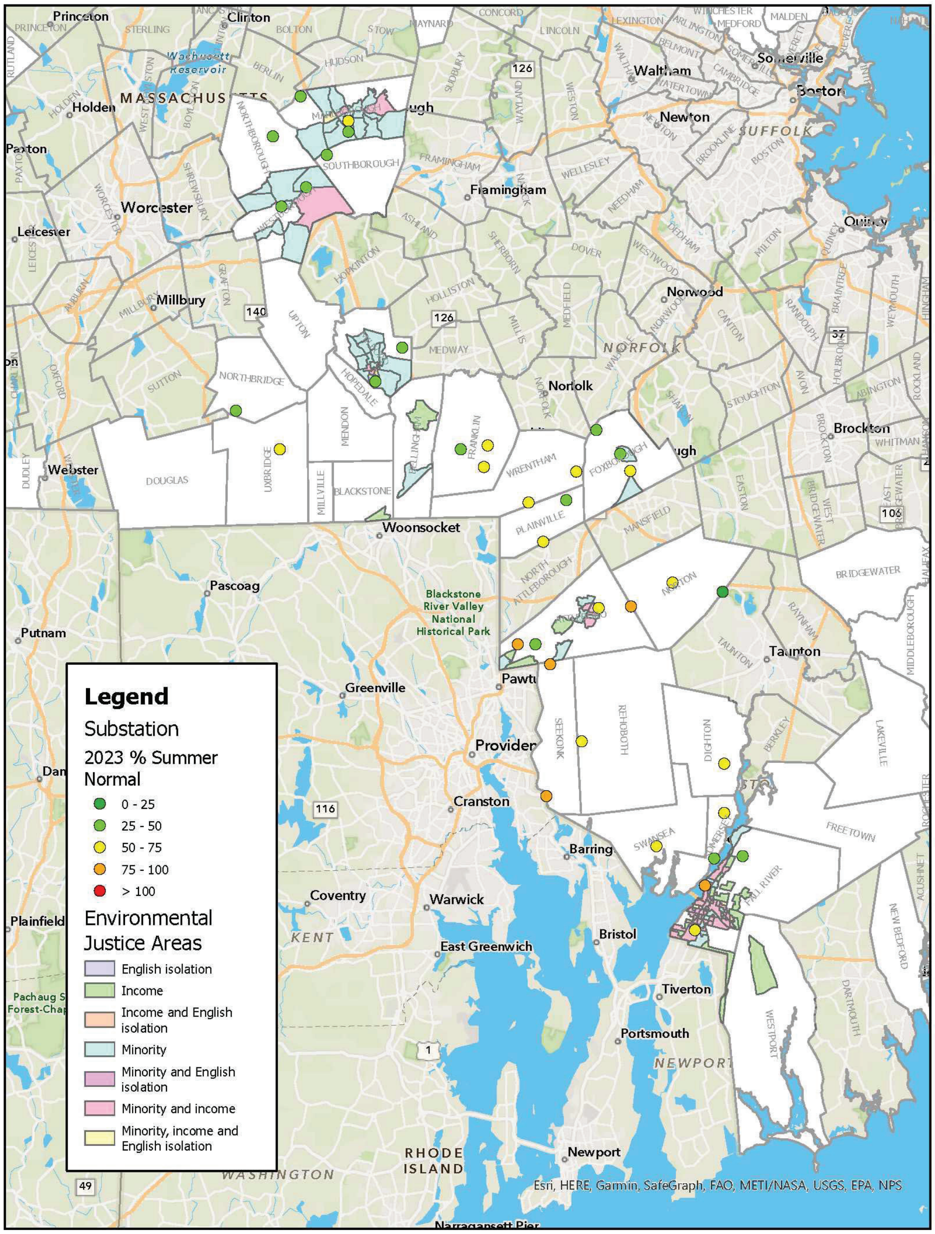
[24] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map.

Exhibit 4.77 displays projected 2023 summer normal loading at each substation in the Southeast region.[25] While no transformers were projected to be loaded over their 100% of summer normal ratings, there are five loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

Exhibit 4.77: Southeast Sub-Region Substation Transformer Loading in 2023



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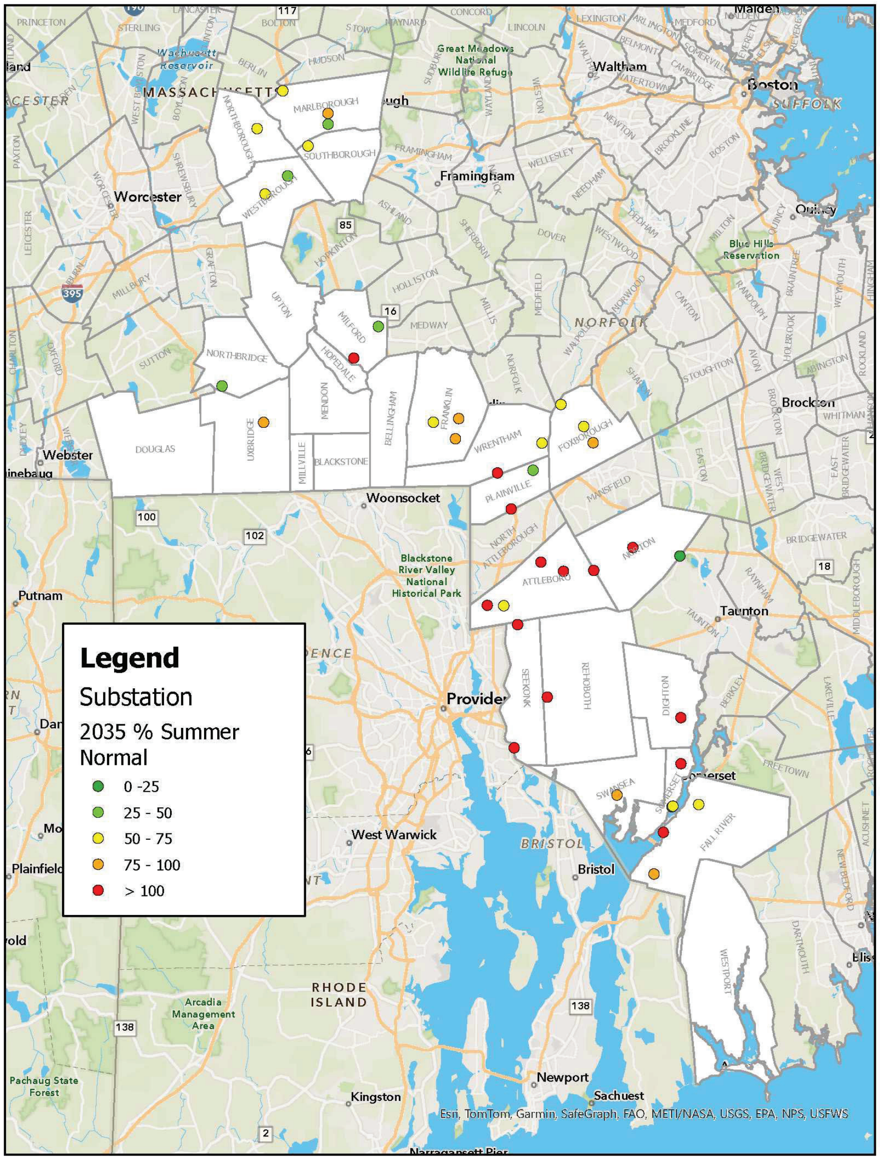
[25] The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Exhibit 4.78 below shows where the projected overloads will happen.

Exhibit 4.78: Southeast Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.6.2 Customer Demographics

Exhibit 4.79: Southeast Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts)*	**231,799**	-
Residential	202,218	87%
Residential – Low Income Rate Participants	*23,996*	-
Business, Commercial, Municipal, or University	29,581	13%

The Company serves a total of 231,799 customers (defined by individual accounts, not the number of people served) – in the Southeast sub-region. Approximately 87% (202,218) of these customers are residential customers and the other 13% are comprised of commercial, municipal, or university customers.

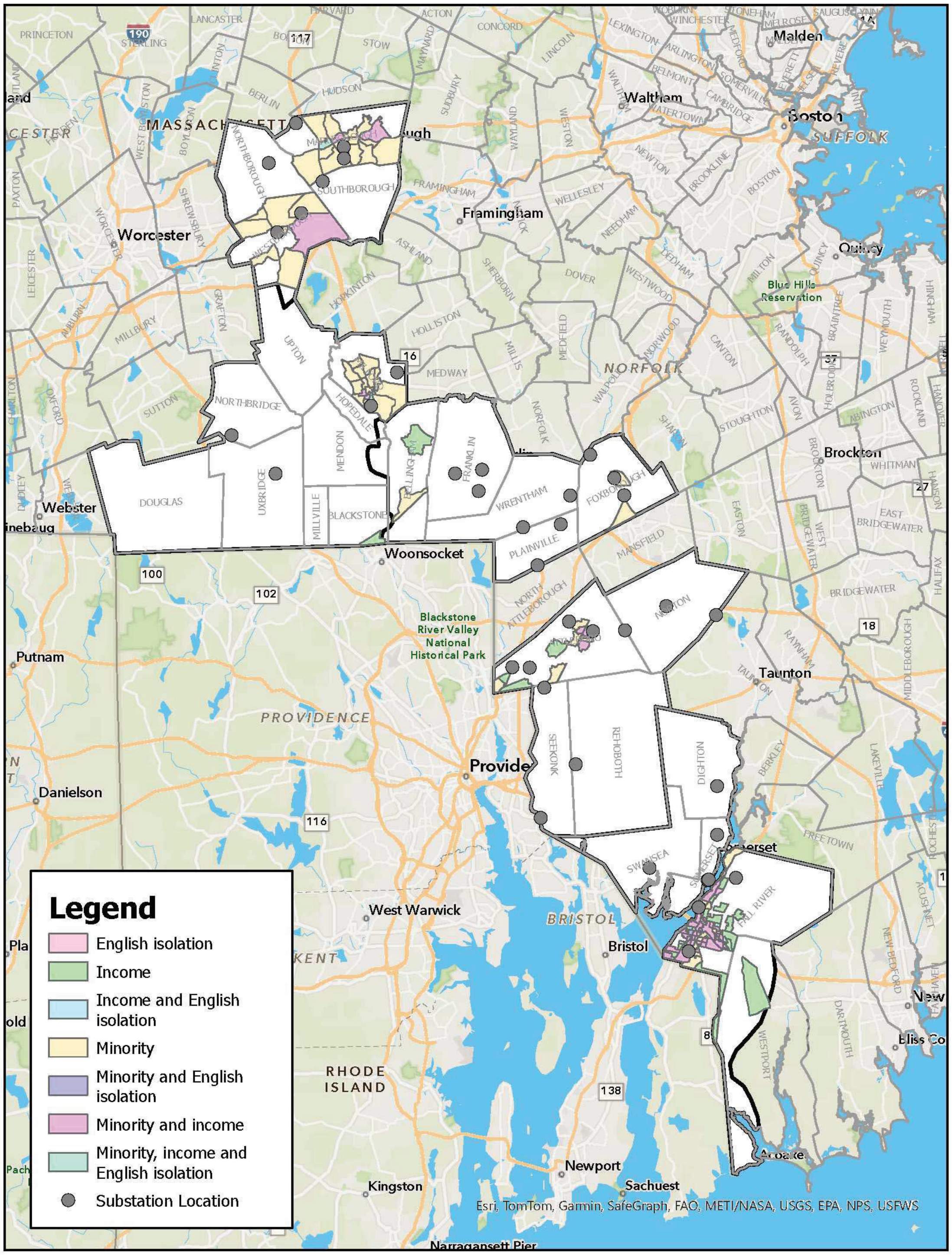
In addition to the Mass Save programs which have benefited customers in the Southeast region, 24 municipalities statewide have been identified for targeted outreach per the Company's MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the Southeast sub-region are Attleboro and Fall River.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing, please refer to the Appendix for those drafts.

Exhibit 4.80 below is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022.[26] Exhibit 4.80 highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many Environmental Justice Areas have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain Environmental Justice Populations, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[26] Multiple substations in close proximity with one another may appear to be overlapping or as one dot on this map.

Exhibit 4.80: Southeast Sub-Region Substation Locations in Relation to the Commonwealth's EJCs



4.6.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the Southeast sub-region, two communities (Attleboro and Westborough) have completed decarbonization plans, and 21 are designated as green communities. The region's FY23-28 CEDS focuses on workforce development, reducing unemployment, and fostering modern infrastructure investment, including utility infrastructure, to enable continued growth. The strategy is committed to exploring alternative energy sources, with an emphasis on leveraging the region's strong marine and ocean-based industries to become a hub for the off-shore wind industry.

4.6.4 Electrification Growth

Heat Electrification - The Southeast sub-region has experienced significant growth in heat pump adoption. Approximately 2,000 units have been adopted by the end of 2022, of which nearly 80% are hybrid.

Transport Electrification – There has been steady growth in the LDEV sales in the Southeast sub-region with about 5,000 vehicles as of the end of 2022. However, the MHDEVs penetration is very low at present. Since 2019, The Company has installed 390 EV charging ports via their phase I and phase II EV charging programs in the Southeast region.

4.6.5 DER Adoption (Battery Storage and Solar Photovoltaic)

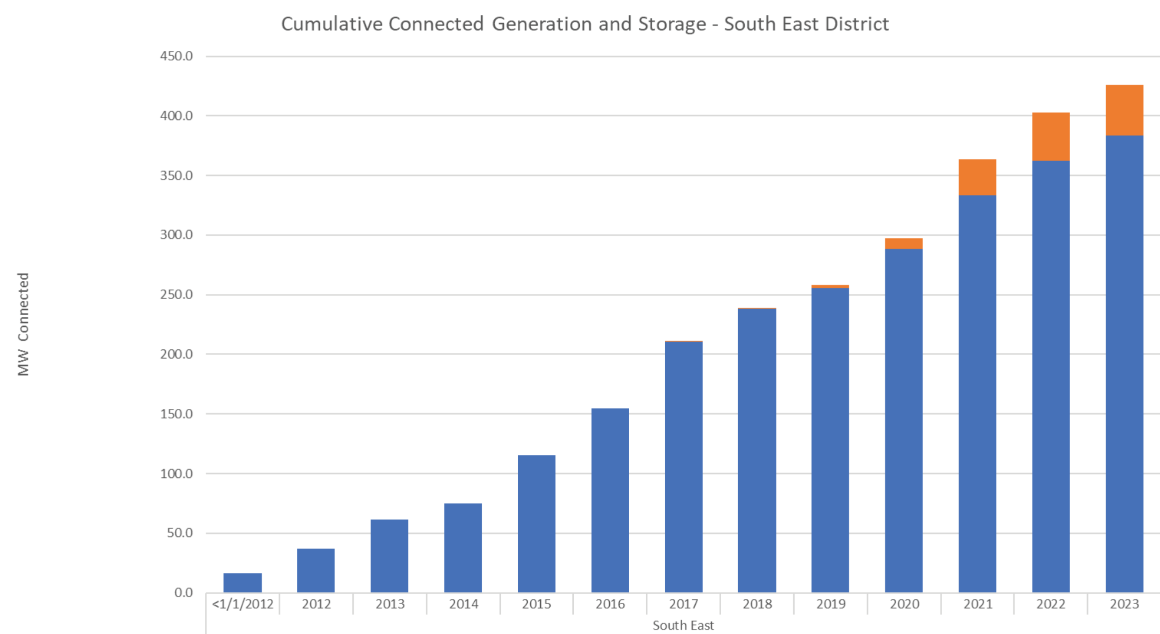
With a total of 425.6 MW of generation connected, the Southeast sub-region has relatively high DER penetration. Connected DER is overwhelmingly solar, representing approximately 95% of the installed DER capacity.

Exhibit 4.81: Southeast Sub-Region DER Adoption Summary

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	363.3	108.0
Battery	42.0	332.3
Hydro	0.1	0.0
Wind	2.0	0.0
Miscellaneous	18.3	0.6
Total	**425.6**	**440.8**

Significant levels of DER have been connected in the Southeast sub-region, predominantly in the past decade. Note that in Exhibit 4.81, the 2023 value is reflective of cumulative interconnections as of July 2023.

Exhibit 4.82: Southeast Sub-Region Cumulative Connected Generation and Storage



	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	2.7	8.9	30.4	40.5	42.0
Sum of Total Generator MW	16.7	37.3	61.6	75.1	115.3	154.6	210.4	238.0	255.6	288.7	333.3	362.5	383.6

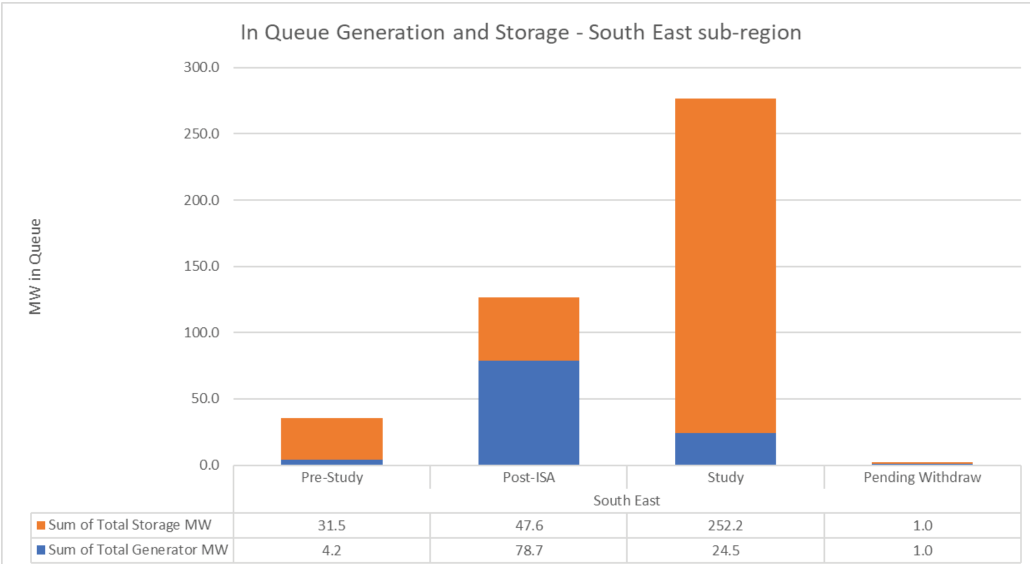
Exhibit 4.83 contains visibility of the current DER interconnection queue in the Southeast sub-region. As shown in the exhibit, recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 64% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid hosting capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.6.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

Exhibit 4.83: Southeast Sub-Region Pending DER Summary in Queue

Sub-Region	Solar (MW)	Battery (MW)	Hydro (MW)	Wind (MW)	Miscellaneous[2] (MW)	Grand Total (MW)
Southeast – Pending DER	108.0	332.3	0.0	0.0	0.6	440.8

Exhibit 4.84: Southeast Sub-Region Pending DER Generation and Storage in Queue



Between the 440.8MW pending in queue, awaiting interconnection, and the 425.6MW already connected in the Southeast sub-region, the total for the area would be 866MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion. Layering on the complexity of battery operation and solar variability, advanced grid management tools will be necessary in addition to the infrastructure build out to maintain the safety and reliability of the grid.

In the Southeast sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas:[3]

- Attleboro
- Fall River (North and South)
- Hopedale West
- Hopedale East

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the CIP cost allocation methodology, process, and Provisional System Planning Provision to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- Enabled electrification: the proposed solution in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.

- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 91 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of seven substation transformers and approximately 30 miles of distribution line construction, at an estimated cost of $220M.

4.6.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

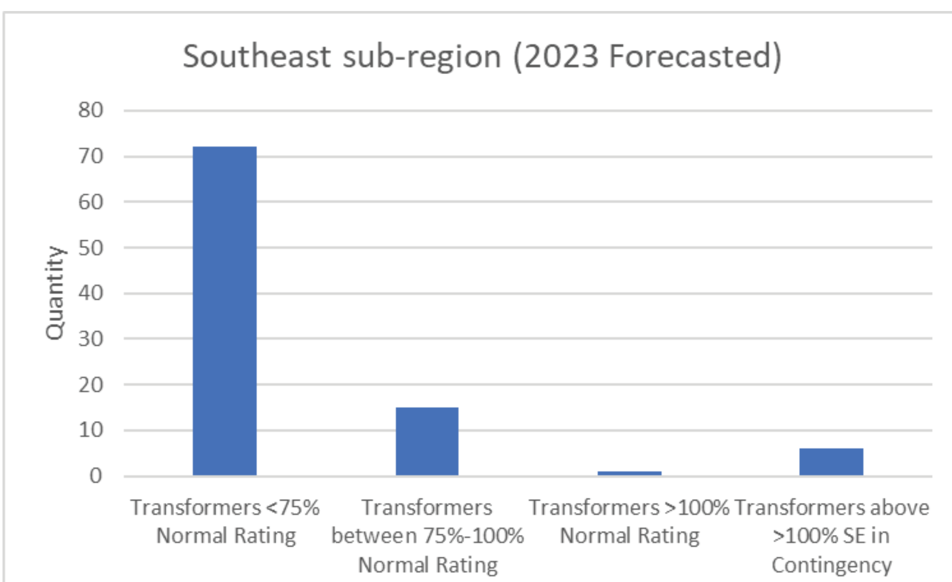
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the Southeast sub-region over 8,000 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 26 MW of load on the grid when the overall grid is at peak.

4.6.7 Capacity Deficiency

The exhibits below summarize the asset loading across the Southeast sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.85: Southeast Sub-Region 2023 Forecasted Transformer Loading Profile

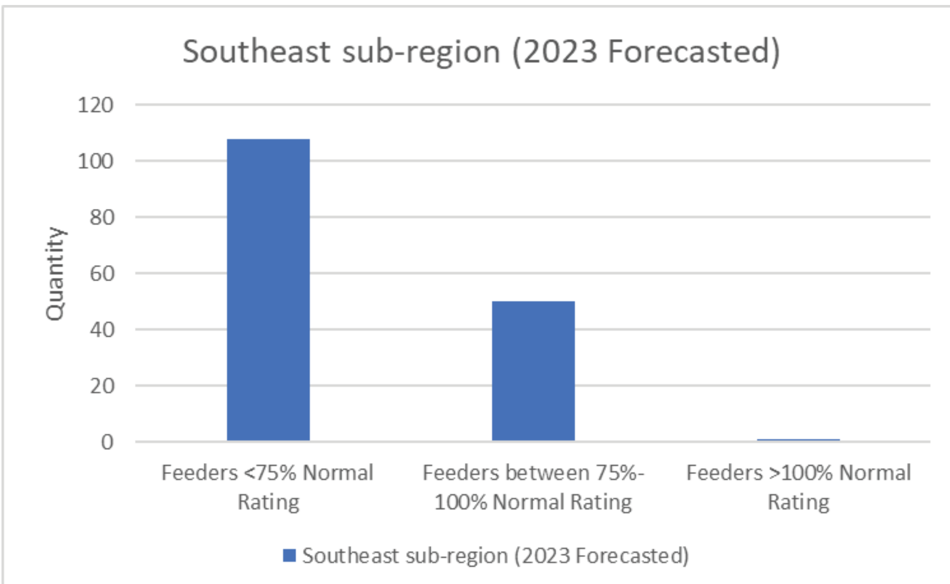


Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.86: Southeast Sub-Region 2023 Forecasted Transformer Capacity Deficiencies

Study Area	Substation	Capacity Deficiency
Fall River	Hathaway Substation	Transformer > 100% Normal Rating
Attleboro	Mink Street	Transformers > 100% Emergency Rating in Contingency
Hopedale East	Union Street	Transformers > 100% Emergency Rating in Contingency
Marlboro	Marlborough 311	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.87: Southeast Sub-Region 2023 Forecasted Feeder Loading Profile



One feeder in the Southeast sub-region has an identified existing capacity deficiency. This deficiency is being monitored as an anticipated spot load comes into service, and operational mitigations will manage the overload as appropriate.

The Southeast sub-region features a 23 kV sub-transmission system known as the Union Loop which serves approximately 170 MW in the Attleboro and Hopedale East study areas. The Union Loop supplies 15 substations which step the voltage down from 23 kV to a mixture of 13 kV and 4 kV. The Union Loop has contingency loading and voltage performance concerns that limit the amount of load growth that can be supported by these substations.

Much of the Southeast sub-region shares a border with Rhode Island, and in some cases distribution facilities from one jurisdiction are supplied from the neighboring utility. In such cases, infrastructure investments in these areas must consider Rhode Island Electric as a critical stakeholder.

4.6.8 Aging Infrastructure

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases, and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, the Company drives asset replacement primarily by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria on their asset health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can greatly enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 4.88 below shows the metal clad age profile in the Southeast sub-region. Metalclads are further described in Section 4.3.8.

Exhibit 4.88: Southeast Sub-Region Metalclad Age Profile

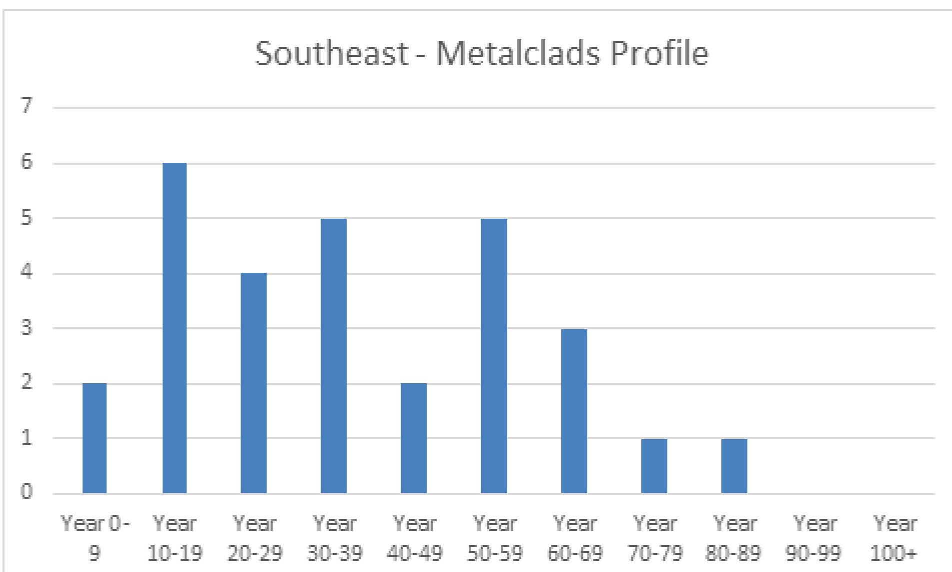


Exhibit 4.89 shows the substation transformer age profile in the Southeast sub-region.

Exhibit 4.89: Southeast Sub-Region Substation Transformer Age Profile

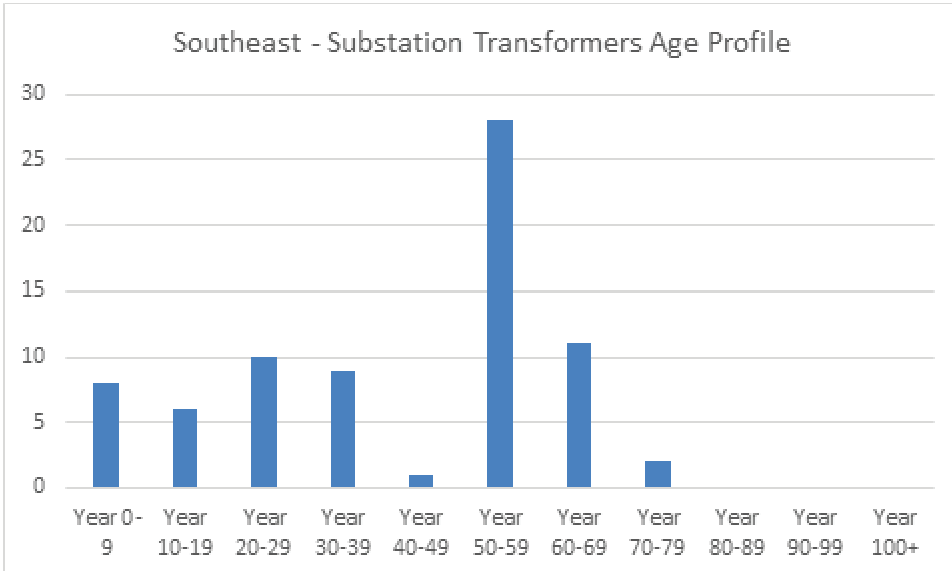


Exhibit 4.90 shows the distribution pole age profile in the Southeast sub-region.

Exhibit 4.90: Southeast Sub-Region Distribution Pole Age Profile

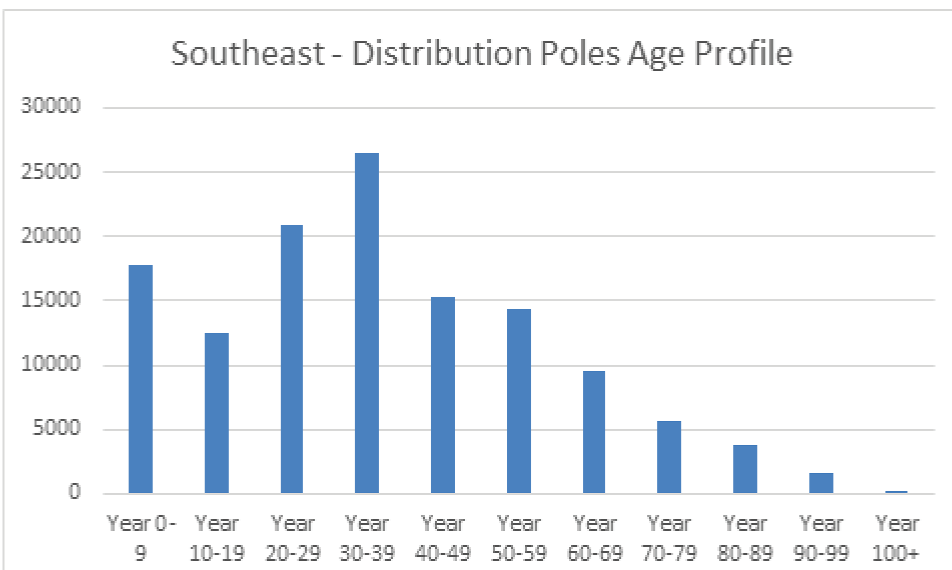
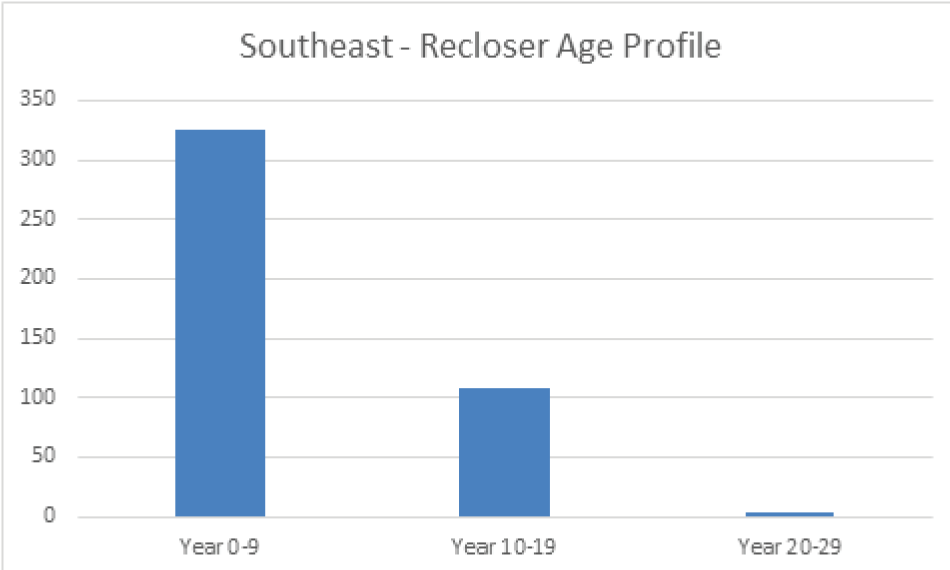


Exhibit 4.91 shows the recloser age profile in the Southeast sub-region.

Exhibit 4.91: Southeast Sub-Region Recloser Age Profile



4.6.9 Reliability and Resilience

This Section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality Guidelines.[27] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this Future Grid Plan. The investments proposed in the Future Grid Plan are driven by load growth and the need to increase system capacity.

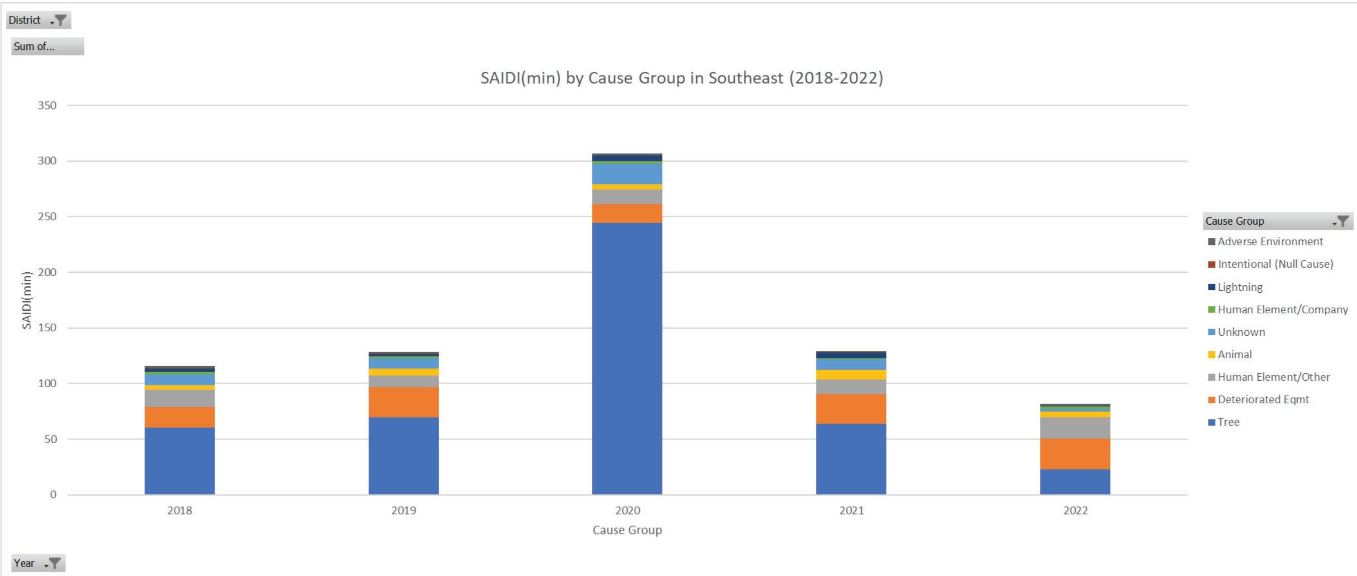
Refer to Section 4.3.9 for background on reliability metrics and performance.

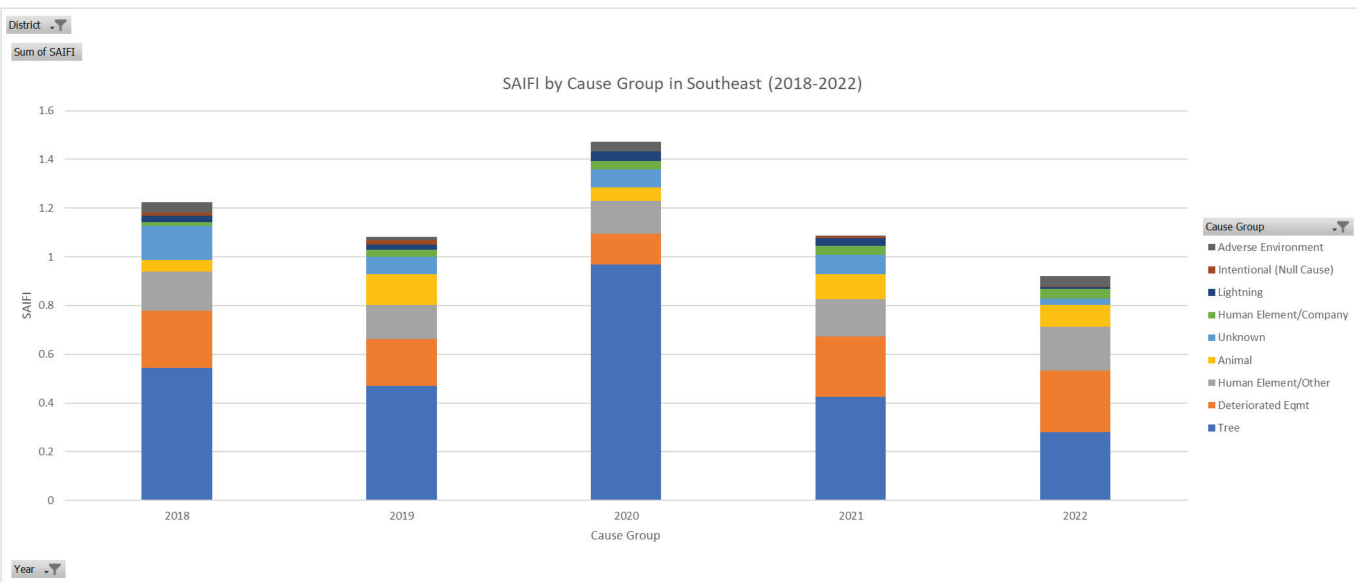
Reliability performance

Exhibit 4.92 show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

[27] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

Exhibit 4.92: Southeast Sub-Region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance





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SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
3rd Quartile	2nd Quartile	3rd Quartile	3rd Quartile	2nd Quartile

Sum of SAIDI Medium Quartile				
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Refer to Section 4.3.9 for background on how reliability metrics are calculated.

Resiliency performance

As described in Section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in Section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs, as defined by the Commonwealth. The exhibits below show the Company’s distribution substation locations within the Southeast sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.93: Southeast Sub-Region Resiliency in EJCs as shown as SAIDI Substation Performance

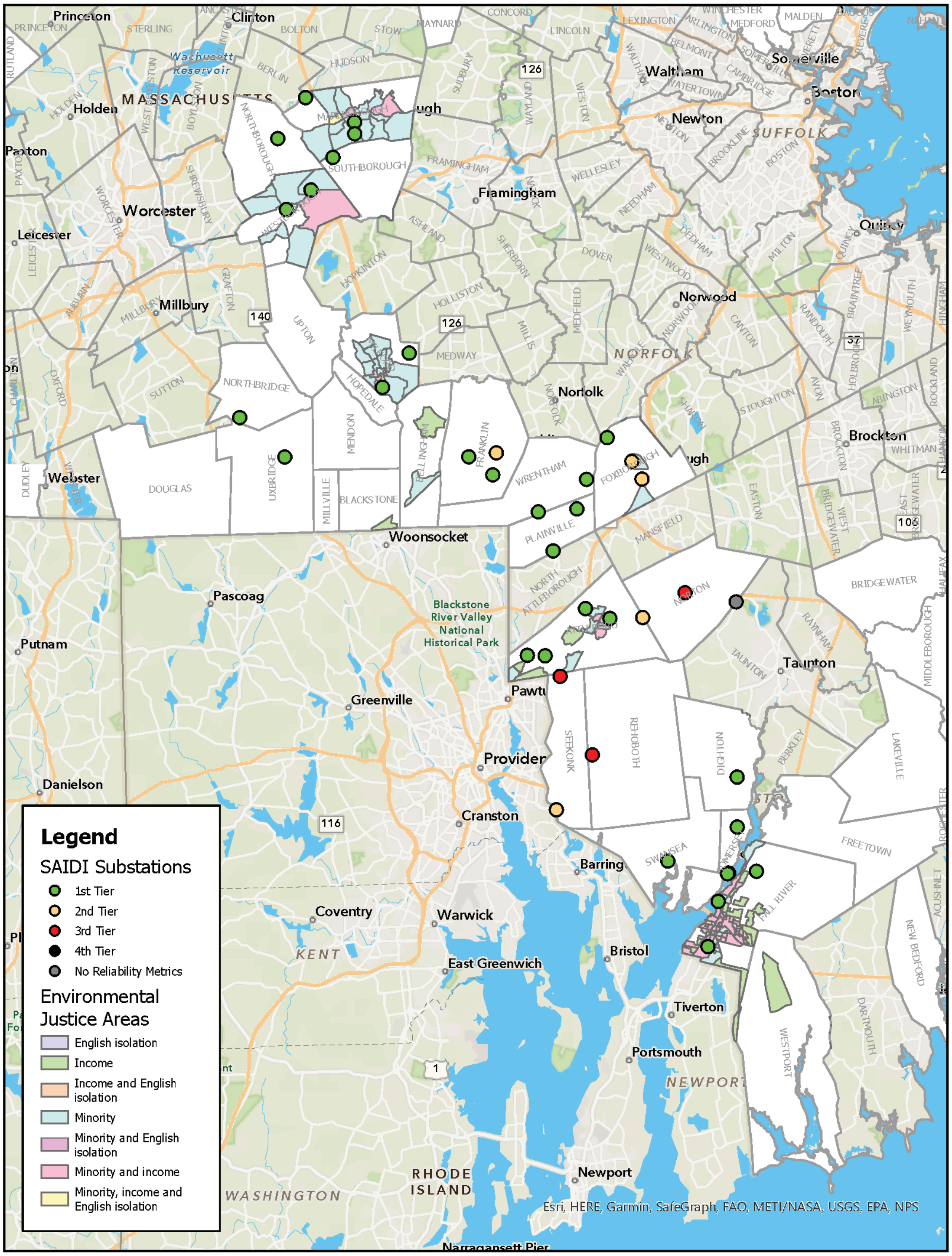
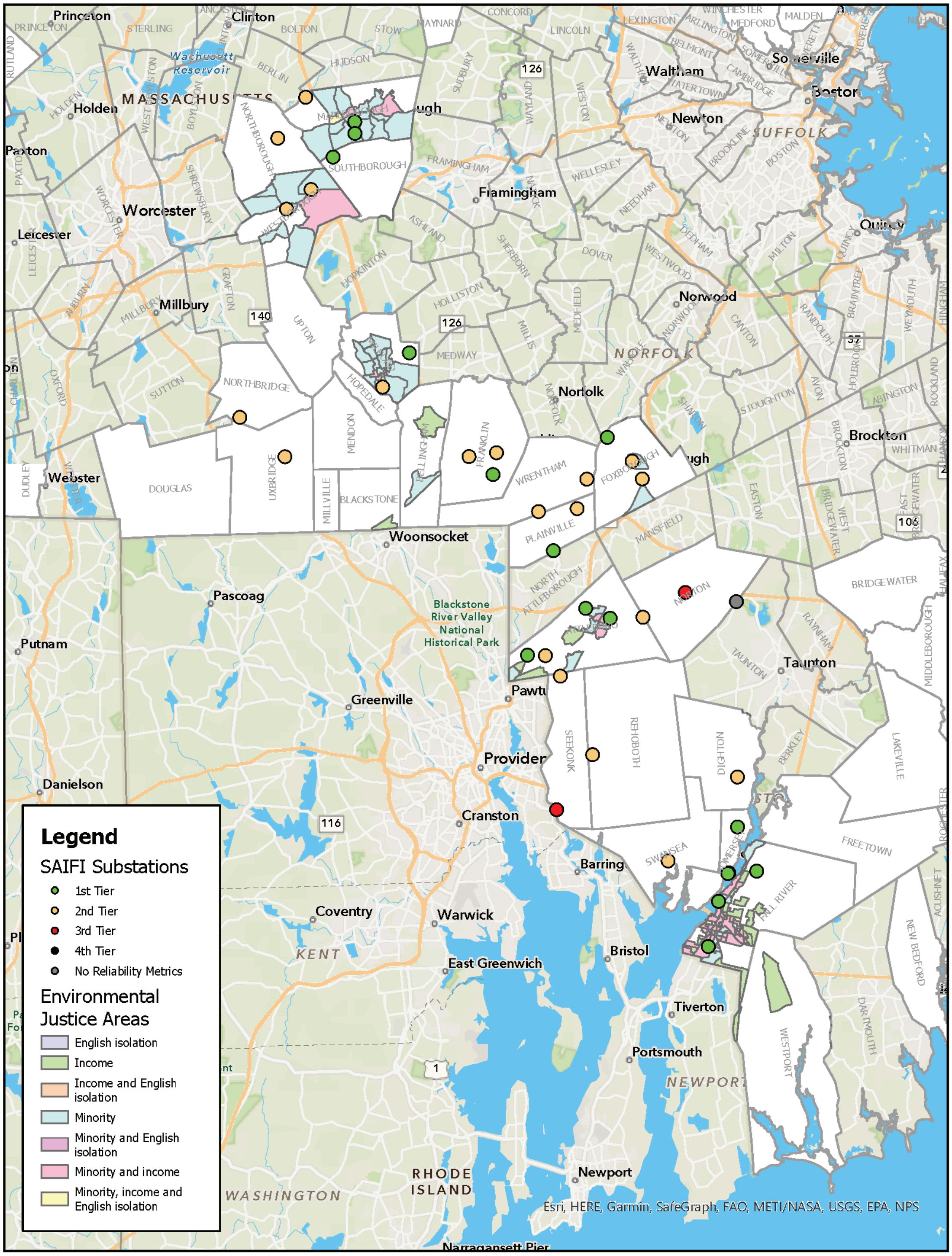


Exhibit 4.94: Southeast Sub-Region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.6.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with state requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

Since the Southeast sub-region is one of the more developed regions, the Company has faced increased challenges in identifying suitable locations for energy infrastructure. Each site presents different siting and environmental considerations, especially given the wetland mitigation requirements for permanently impacted land.

4.7 South Shore Sub-Region

The South Shore sub-region in brief:

Nature of the area: The South Shore sub-region is predominantly suburban, with regional urban centers in Brockton and Quincy.

The Company's customers' energy needs, economic circumstances and demographics in the South Shore sub-region vary, which is why targeted, and culturally competent community engagement is at the core of the Company's plan to help the Commonwealth achieve its goals.

Exhibit 4.95: South Shore Sub-Region Customers by the Numbers

Description	Value	Unit
Number of Substations	39	Count
Number of Feeders	187	Count
Total Length of Feeders	2,932	Miles
Total Peak Load Served	938	MW
Sub-region Area	404	Square Miles
Benefits of EE	1,206,558	MWh
Heat Pump Adoption	1,470	Count
Charging Ports Installed	244	Count
5- Year Residential Population Growth Projections	2.2%	Percent
5- Year Forecasted Load Growth	6.5%	Percent
Existing Connected Rooftop DER (< 25kW)	90	MW

Context of the region

The South Shore sub-region includes several dense urban areas which have a highly integrated network and also some more sparse suburban areas which have a more radial network. The South Shore sub-region has moderate levels of DERs penetration relative to all other sub-regions due to the somewhat limited amount of open space coupled with limited capacity on the distribution system. Due to the growing suburban areas, an approximate 6.5% load growth is expected in the South Shore region in the next 5 years. Additional details can be found in Section 5.

Below are some key characteristics of the South Shore sub-region which will drive future investment needs.

Exhibit 4.96: South Shore Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
Legacy planning and construction practices in the South Shore sub-region led to a high proportion of substations with a single transformer, relying mainly on distribution feeder ties to transfer customers to neighboring substations in the event of a transformer outage. As load has grown in the region these practices have not been sustainable.	To accommodate load growth and continue to provide reliable service to customers, the Company needs to add second transformers at substations throughout the region, many of which were not originally designed to accommodate a second transformer or transmission supply.
Nantucket is a geographical and electrical island supplied by two undersea subtransmission cables which limit the load growth on the island.	Load growth on the Island will require National Grid to establish additional undersea supply cables, which are high cost and high complexity projects.

4.7.1 Maps

The South Shore sub-region consists of 21 municipalities and comprises the study areas below:

Exhibit 4.97: South Shore Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Bridgewater	Bridgewater, Brockton, East Bridgewater, Halifax, Hanson, Pembroke, West Bridgewater, Whitman
2	Brockton	Abington, Brockton, East Bridgewater, Easton, West Bridgewater, Whitman
3	Brockton NW/ Randolph	Abington, Avon, Brockton, Easton, Holbrook, Randolph, Stoughton
4	Hanover	Abington, Brockton, Hanover, Hanson, Holbrook, Norwell, Pembroke, Rockland, Weymouth, Whitman
5	Nantucket	Nantucket
6	Quincy	Quincy
7	Scituate	Cohasset, Hanover, Norwell, Scituate
8	Weymouth/Holbrook	Holbrook, Weymouth

Exhibit 4.98 shows the substation locations within the South Shore sub-region's study areas, indicated with a red dot. Not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.98: South Shore Sub-Region Substation Locations and Study Areas

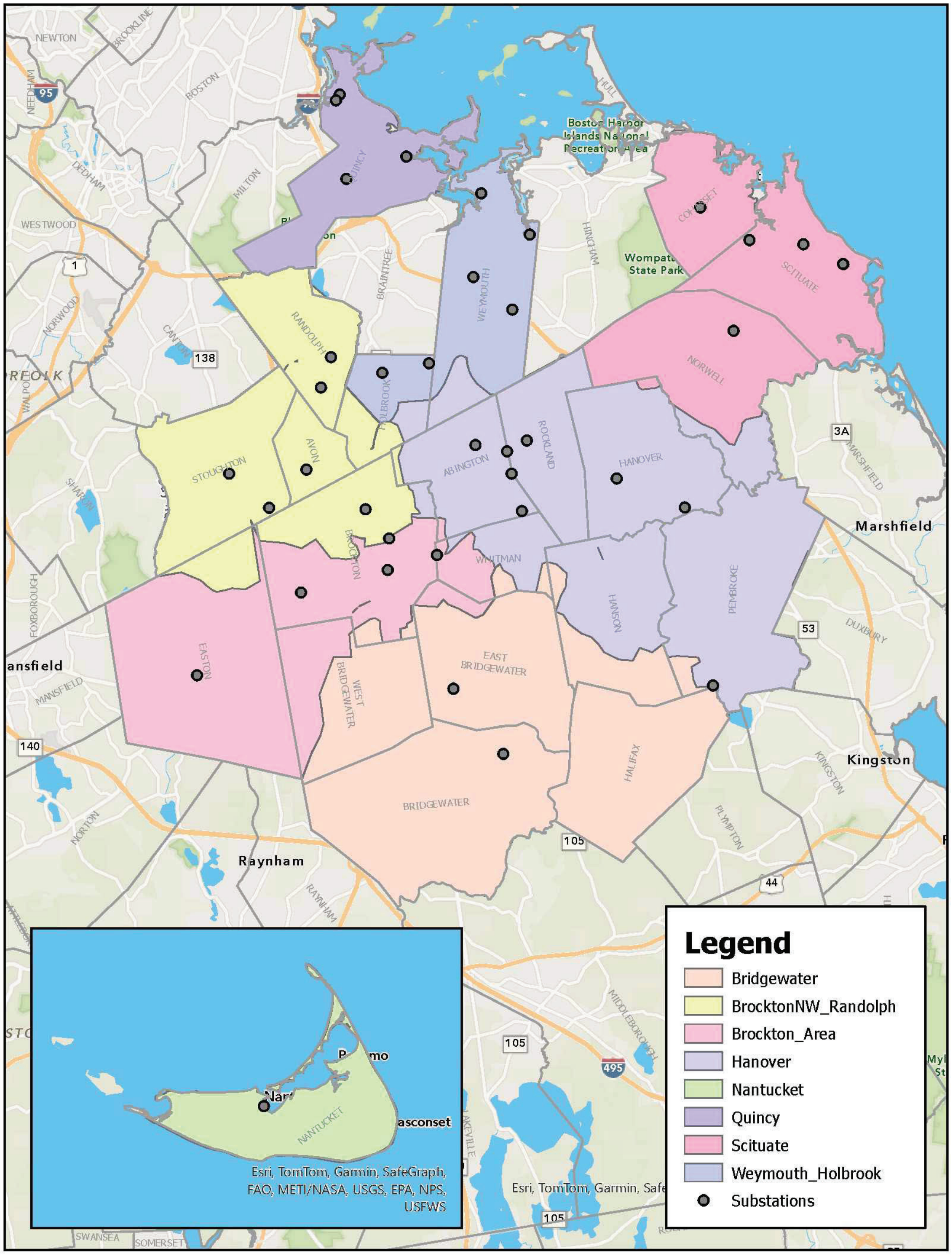
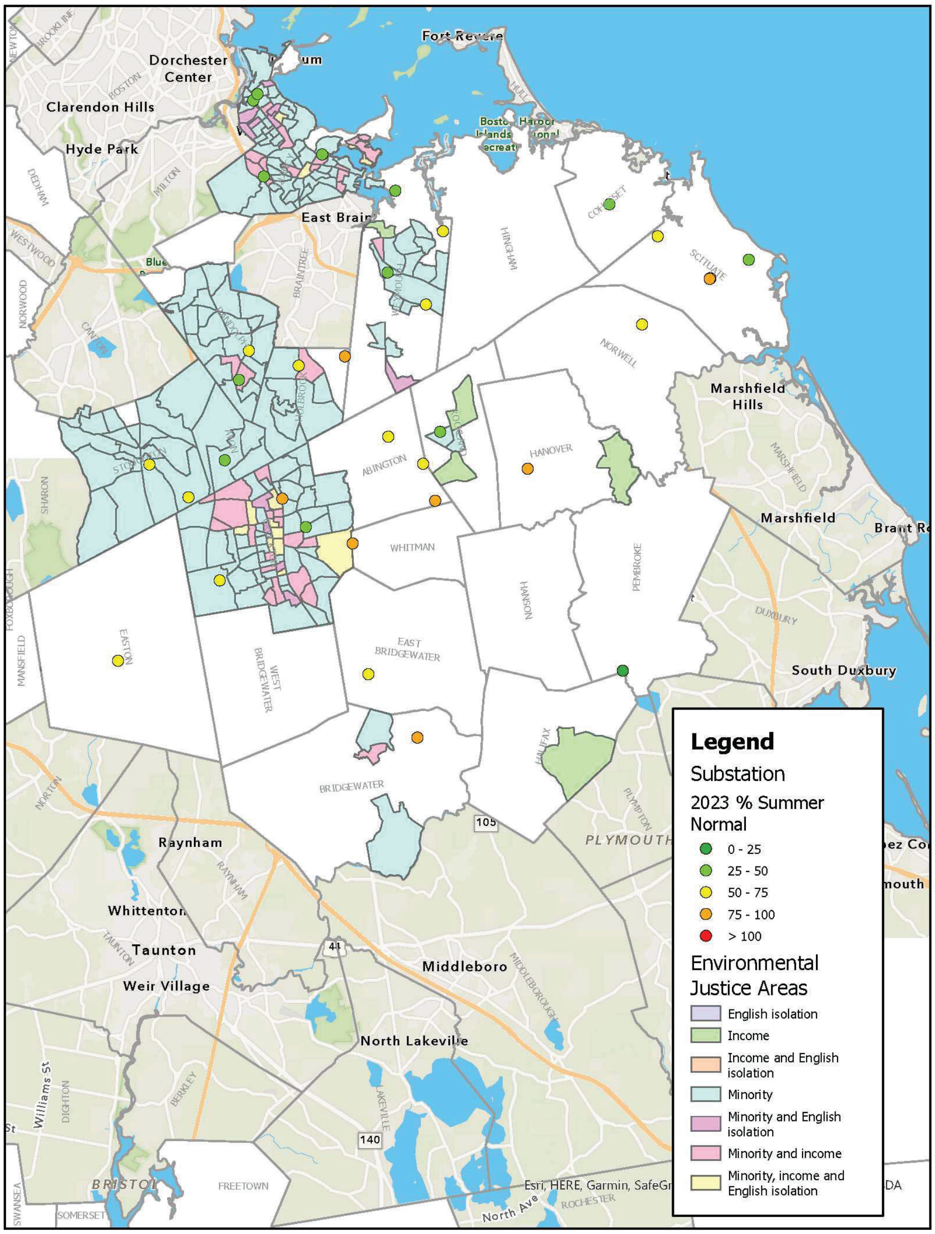


Exhibit 4.99 displays projected 2023 summer normal loading at each substation in the South Shore region.[28] While no transformers were projected to be loaded over their 100% of summer normal ratings, there are seven loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

Exhibit 4.99: South Shore Sub-Region Substation Transformer Loading in 2023



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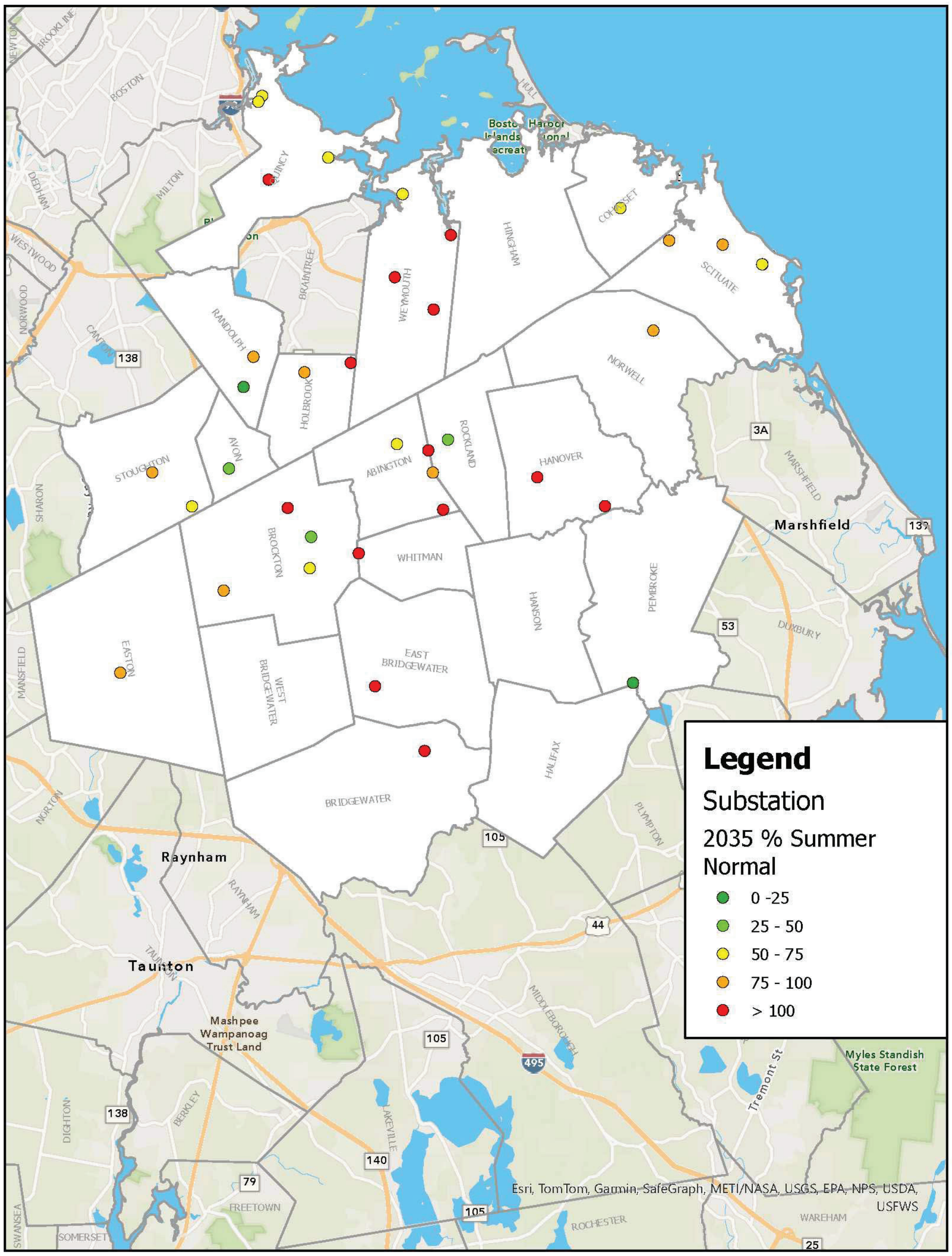
[28] The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Exhibit 4.100 below shows where the projected overloads will happen.

Exhibit 4.100: South Shore Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.7.2 Customer Demographics

Exhibit 4.101: South Shore Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts)*	**239,140**	-
Residential	210,181	88%
Residential – Low Income Rate Participants	*25,105*	-
Business, Commercial, Municipal, or University	28,959	12%

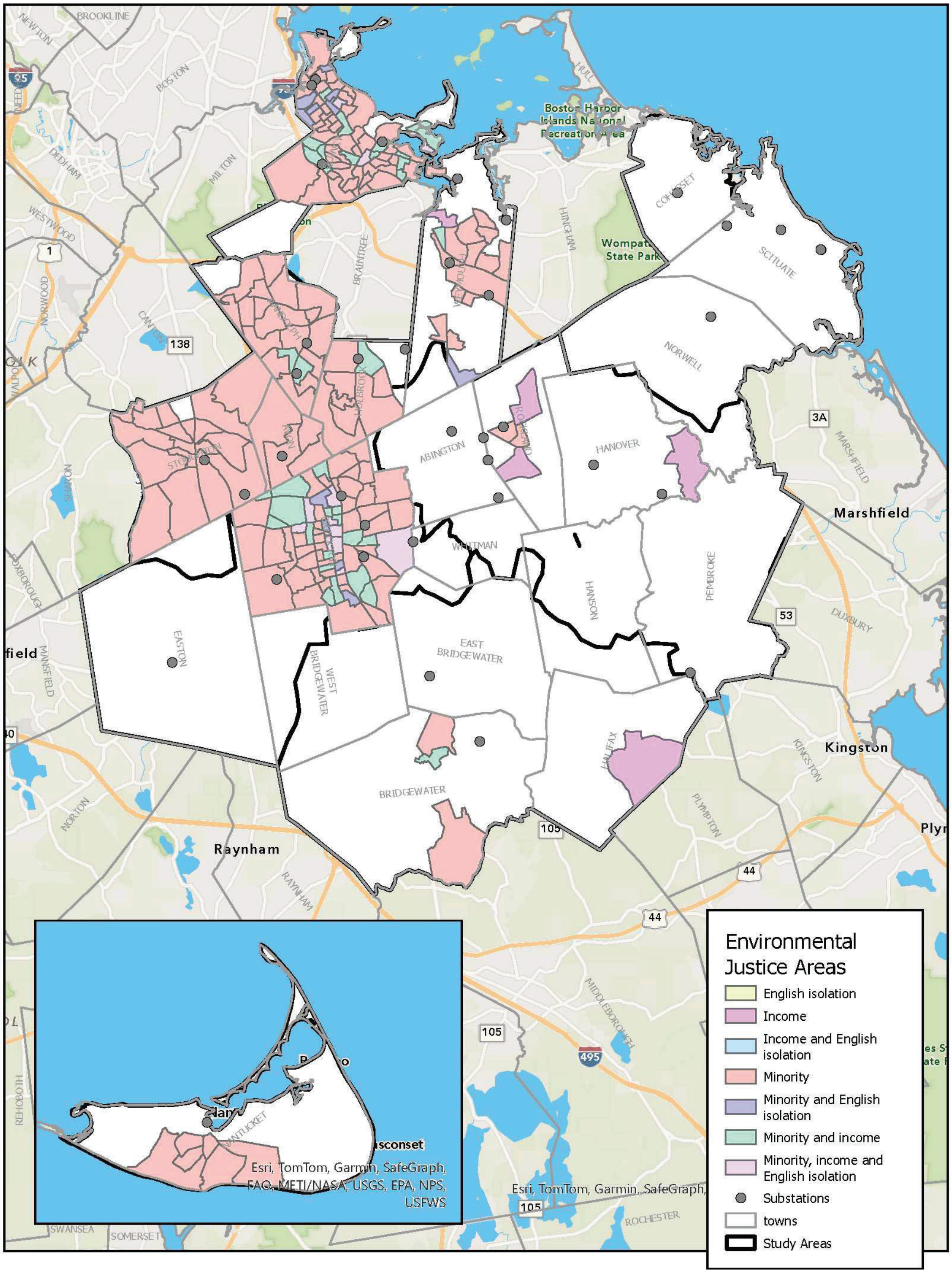
The Company serves a total of 239,140 customers (defined by individual accounts, not the number of people served) – in the South Shore sub-region. Approximately 88% (210,181) of these customers are residential customers and the other 12% are comprised of commercial, municipal, or university customers.

In addition to the Mass Save programs which have benefited customers in the central region, the Company has 24 municipalities statewide identified for targeted outreach per the MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the South Shore region are Brockton, Stoughton, Holbrook, Randolph, and Quincy.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing. Please refer to the Appendix for those drafts.

Exhibit 4.102 is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022. Exhibit 4.102 highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase as well. Many EJCs have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain EJCs, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

Exhibit 4.102: South Shore Sub-Region Substation Locations in Relation to the Commonwealth's EJCs



4.7.3 Economic Development

The development of the Company's Grid Future Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the South Shore sub-region, 20 communities are designated as green communities. In recent years, the region has focused on fostering smart grown and sustainable development, ensuring adequate infrastructure to support economic development, and promoting regional economic self-sufficiency and resilience. Included in the most recent regional CEDS are goals to expand and revitalize commercial land, reuse urban facilities, and support transportation-oriented development to foster economic development and bolster tourism.

4.7.4 Electrification Growth

Heat Electrification - The South Shore sub-region has moderate pump adoption compared to the other five sub-regions. About 1,000 units have been adopted by the end of 2022, of which over 60% are hybrid.

Transportation Electrification – There has been steady growth in LDEV sales in the South Shore sub-region with about 5,000 vehicles as of the end of 2022. However, the total number of MHDEVs is less than 5 indicating very low penetration at present. Since 2019, the Company has installed 244 EV charging ports via their phase I and phase II electric vehicle charging programs in the South Shore region.

4.7.5 DER Adoption (Battery Storage and Solar Photovoltaic)

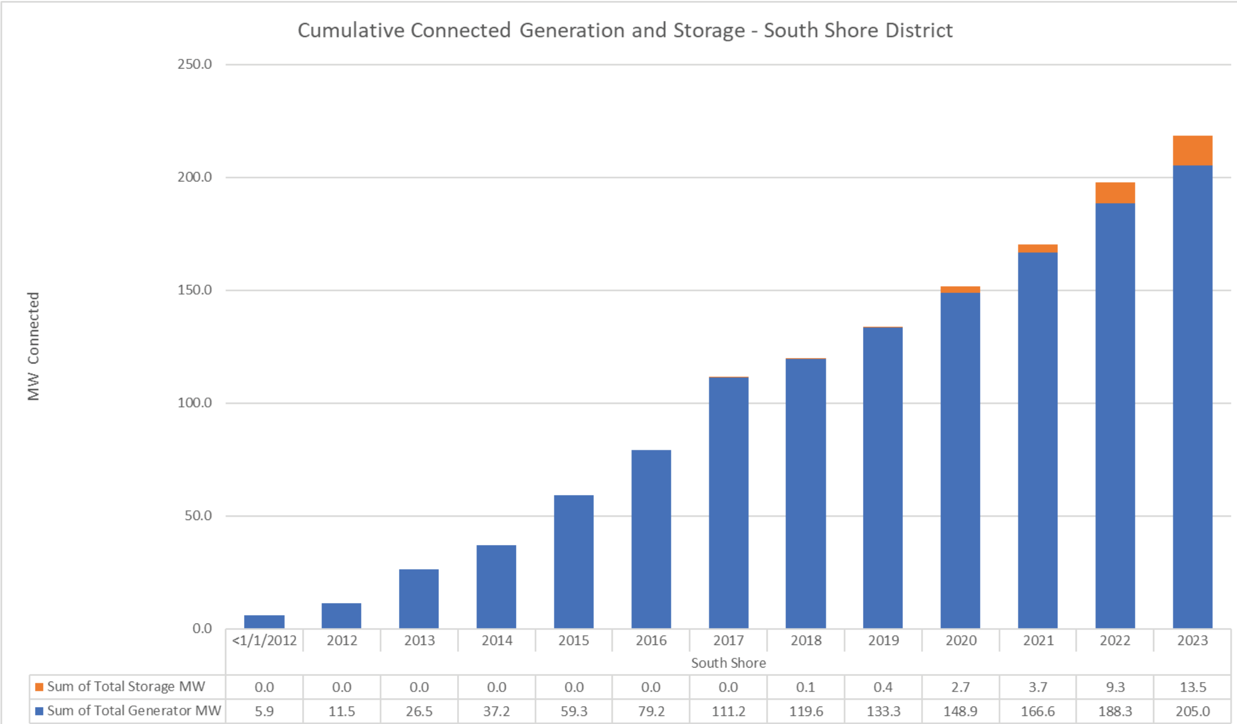
With a total of 218.6 MW of generation connected, the South Shore sub-region has a moderate DER penetration. Connected DER is predominantly solar, representing 94% of the installed DER capacity in the sub-region.

Exhibit 4.103: South Shore Sub-Region DER Capacity Connected and In Queue

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	193.7	60.4
Battery	13.5	194.8
Hydro	0.0	0.0
Wind	2.4	0.0
Miscellaneous	7.5	0.3
Total	**218.6**	255.4

Significant levels of DER have been connected in the South Shore sub-region, predominantly in the past decade. Note that in Exhibit 4.104 below the 2023 value is reflective of year-to-date interconnections as of July 2023. Exhibit 4.104 below shows the cumulative connected DER in the South Shore sub-region.

Exhibit 4.104: South Shore Sub-Region Cumulative Connected Generation and Storage



	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	2.7	3.7	9.3	13.5
Sum of Total Generator MW	5.9	11.5	26.5	37.2	59.3	79.2	111.2	119.6	133.3	148.9	166.6	188.3	205.0

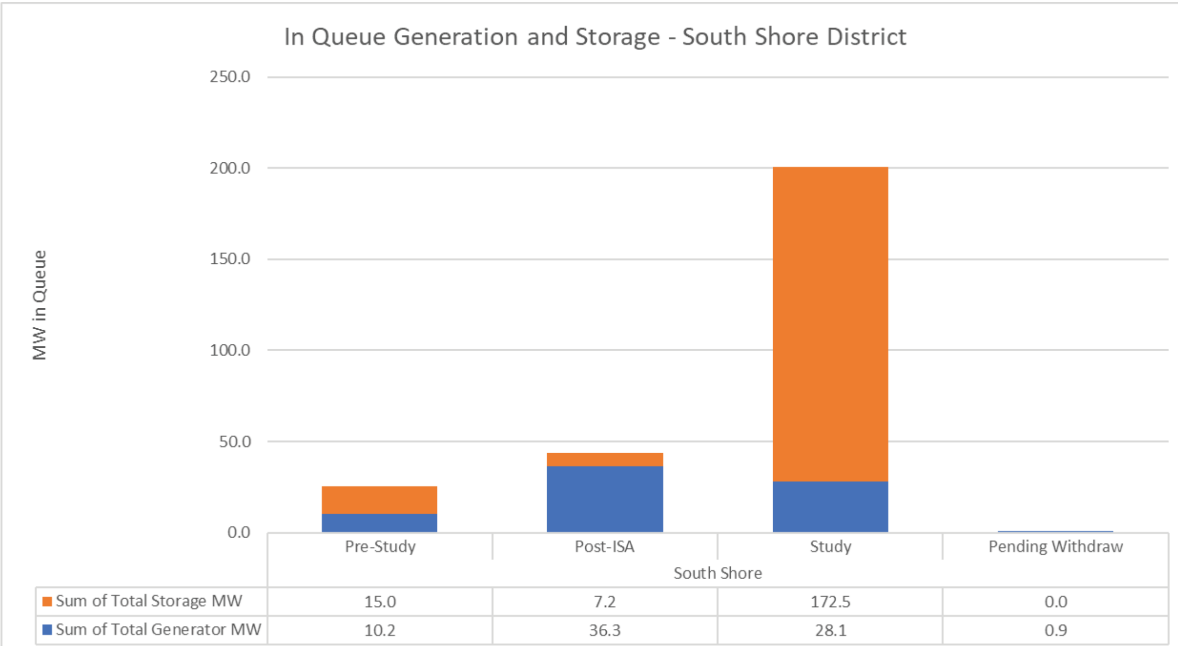
Exhibit 4.104 contains visibility of the current DER interconnection queue in the South Shore sub-region. As shown in the exhibit, recent application trends have demonstrated a shift from largely solar PV applications to mainly battery storage, with batteries representing 72% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.7.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.105 below shows the cumulative queue DER in the South Shore sub-region.

Exhibit 4.105: South Shore Sub-Region Pending DER Generation and Storage in Queue



Combining the 255.4MW in the interconnection queue, and the 218.6MW already connected in the South Shore sub-region, the total for the area would be 474MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion.

In the South Shore sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas[3]:

- Brockton (North and South)
- Bridgewater
- Hanover
- Scituate

The proposed DER and system modifications required for the proposed groups have been included in the base case for the Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the CIP cost allocation methodology, process, and Provisional System Planning Provision to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions

- Enabled electrification: the proposed solution in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.
- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 86 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of three substation transformers and approximately 17 miles of distribution line construction, at an estimated cost of $168M.

4.7.6 Grid Services (Demand Response, Smart inverter Controls, Time-varying Rates)

The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in Sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

In the South Shore region over 7,000 customers currently participate in the Company's ConnectedSolutions DR program and help to reduce approximately 18 MW of load on the grid when the overall grid is at peak.

4.7.7 Capacity Deficiency

The graphs below summarize the asset loading across the South Shore and Nantucket sub-regions in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.106 displays the 2023 forecasted transformer loading in the South Shore sub-region.

Exhibit 4.106: South Shore Sub-Region 2023 Forecasted Transformer Loading Profile

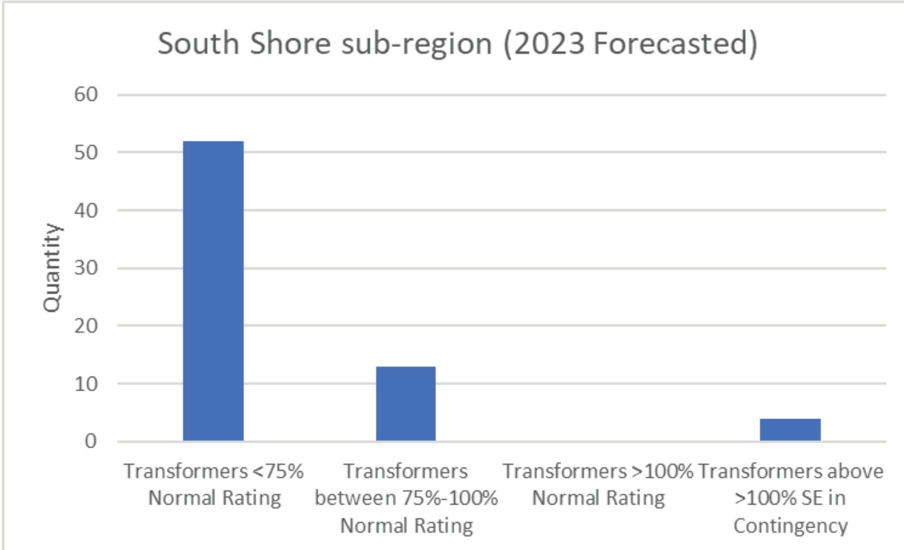
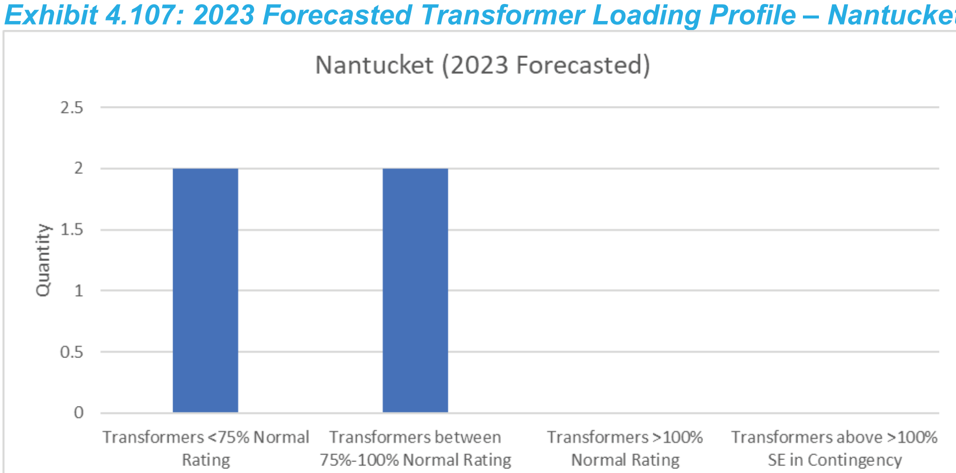


Exhibit 4.107 below displays the 2023 forecasted transformer loading in Nantucket.

Exhibit 4.107: 2023 Forecasted Transformer Loading Profile – Nantucket



Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.108: South Shore Sub-Region 2023 Forecasted Transformer Capacity Deficiencies

Study Area	Substation	Capacity Deficiency
Bridgewater	East Bridgewater	Transformer > 100% Normal Rating
Brockton NW /Randolph	South Randolph 97	Transformers > 100% Emergency Rating in Contingency
Brockton	Dupont 91	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.109: South Shore Sub-Region 2023 Forecasted Feeder Loading Profile

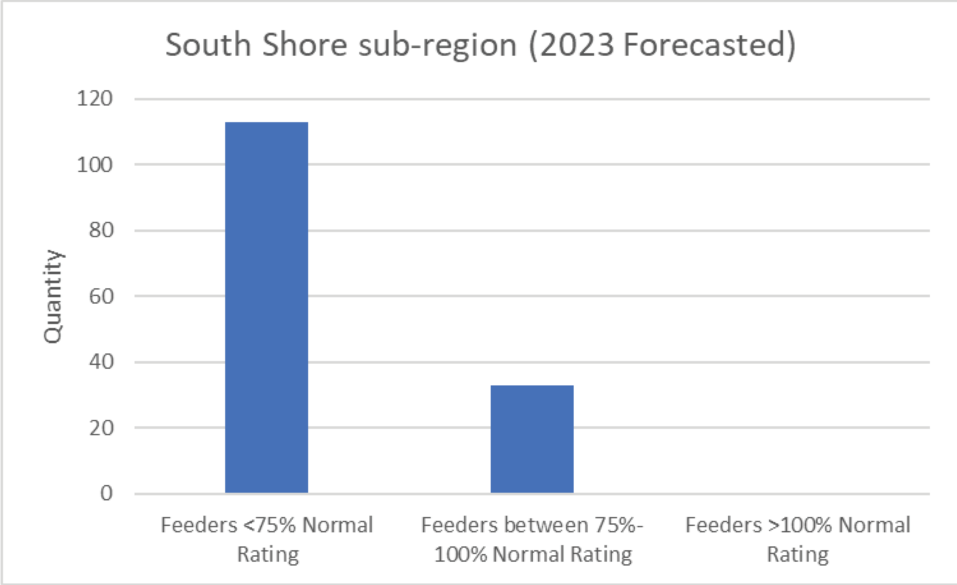
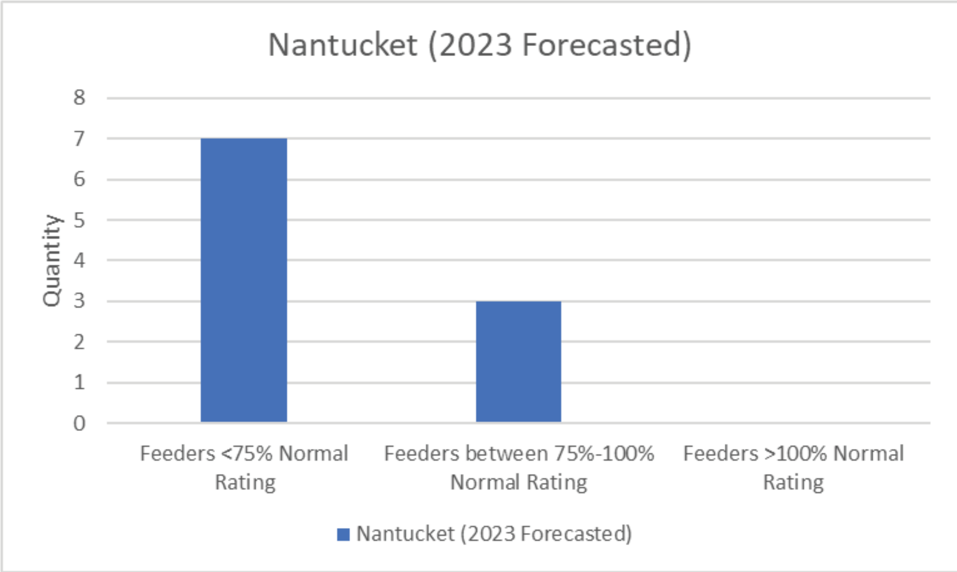


Exhibit 4.110: South Shore Sub-Region 2023 Forecasted Feeder Loading Profile – Nantucket



The South Shore sub-region has two large urban areas of Quincy and Brockton that are experiencing large load growth. Space within these areas is limited, and parcels of land to add and/or upgrade existing infrastructure will prove difficult to accommodate the load growth. Other portions of the South Shore are more suburban and rural with longer distribution circuits, which makes voltage regulation and reliability more difficult to achieve.

There is also a lack of transmission infrastructure in the region. Larger capacity transmission lines, like that of 115 kV supply cables, will need to be extended and/or built in order to serve more areas to accommodate the expected load growth.

The island of Nantucket poses a challenge. The island is currently supplied by only two 46 kV submarine cables from Lothrop Ave and Merchants Way substations from Cape Cod. These cables are reaching their maximum capacity limit and more supply will need to be brought over to the island in the near future. Cost estimates for submarine cables are exceptionally high, making the island both a technical and financial challenge to keep up with the expected load growth.

4.7.8 Aging Infrastructure

This Section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of customers and the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company's approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving its infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 4.111 shows the metalclads age profile in the South Shore sub-region.

Exhibit 4.111: The Metalclad Age Profile – South Shore Sub-Region

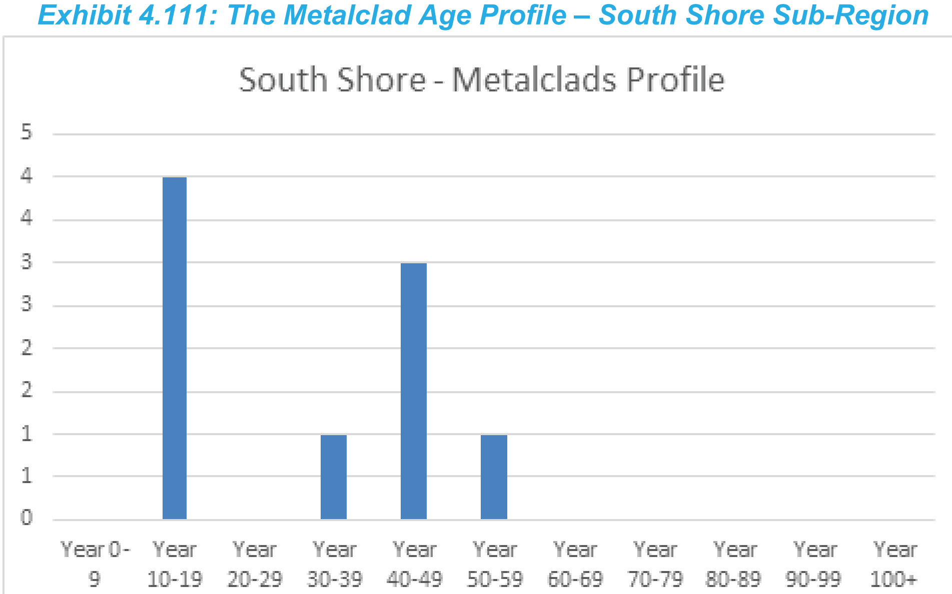


Exhibit 4.112 shows the transformers age profile in the South Shore sub-region.

Exhibit 4.112: South Shore Sub-Region Substation Transformer Age Profile

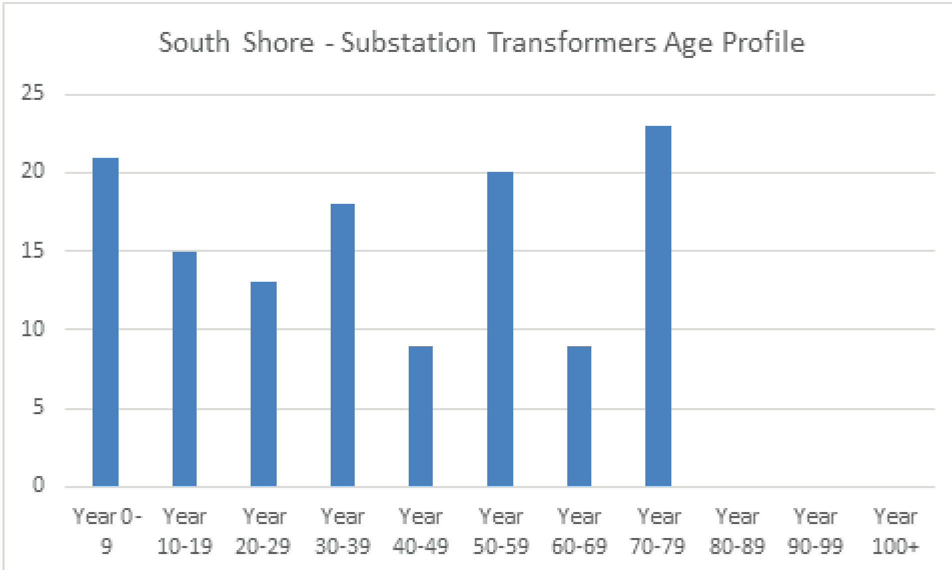


Exhibit 4.113 shows the distribution pole age profile in the South Shore sub-region.

Exhibit 4.113: South Shore Sub-Region Distribution Pole Age Profile

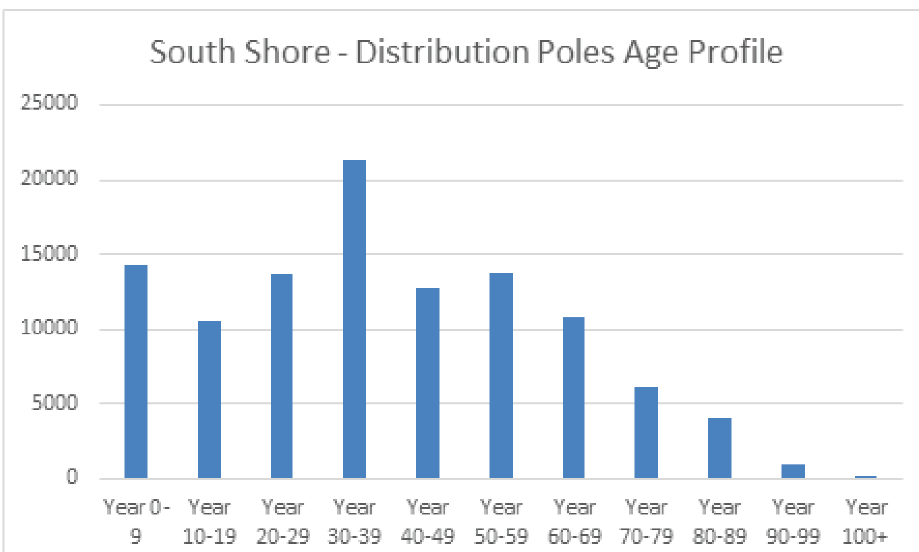
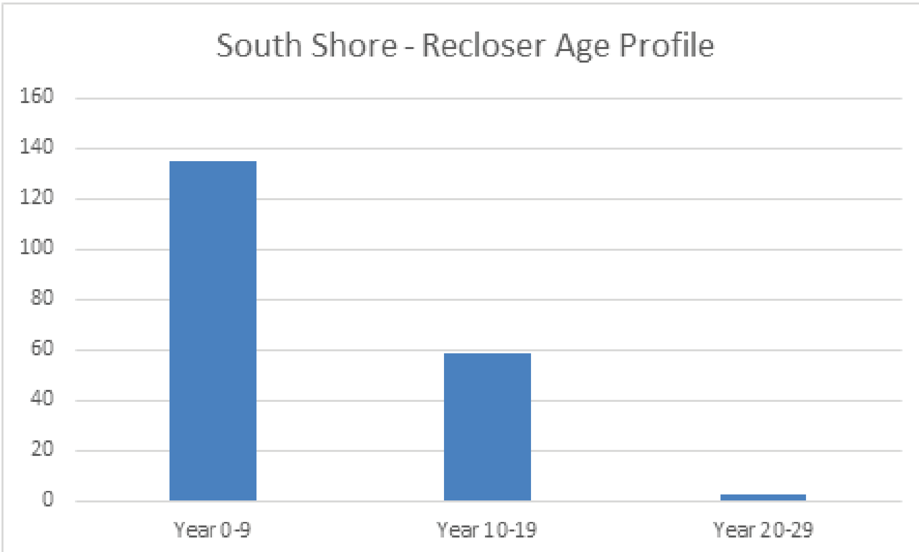


Exhibit 4.114 shows the reclosers' age profile in the South Shore sub-region.

Exhibit 4.114: South Shore Sub-Region Recloser Age Profile



4.7.9 Reliability and Resilience

This Section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality Guidelines.[29] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

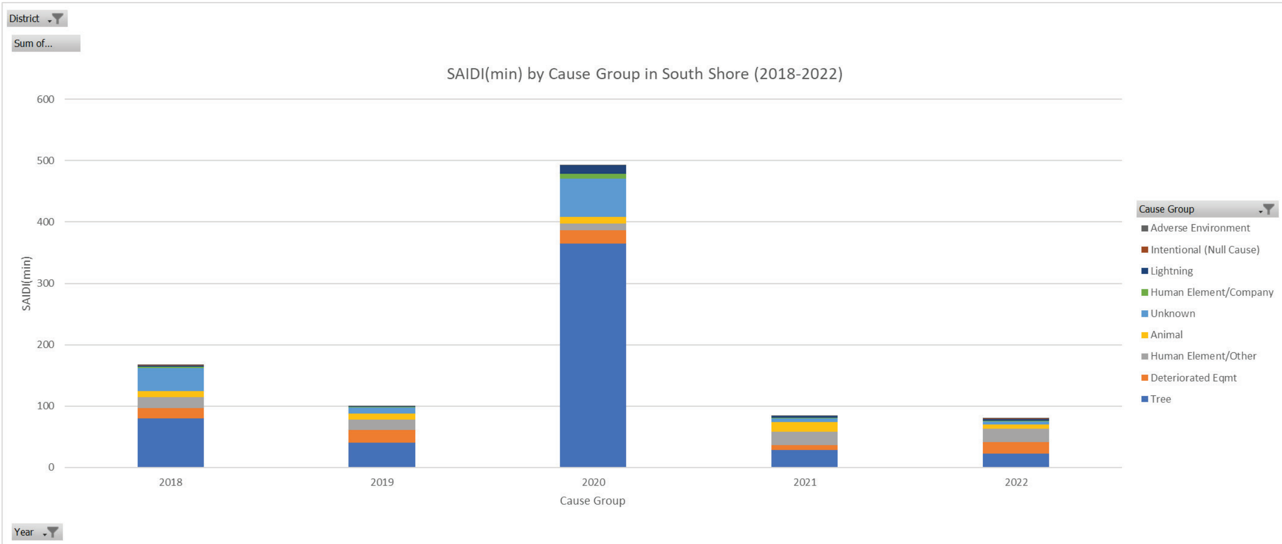
Refer to Section 4.3.9 for background on reliability metrics and performance.

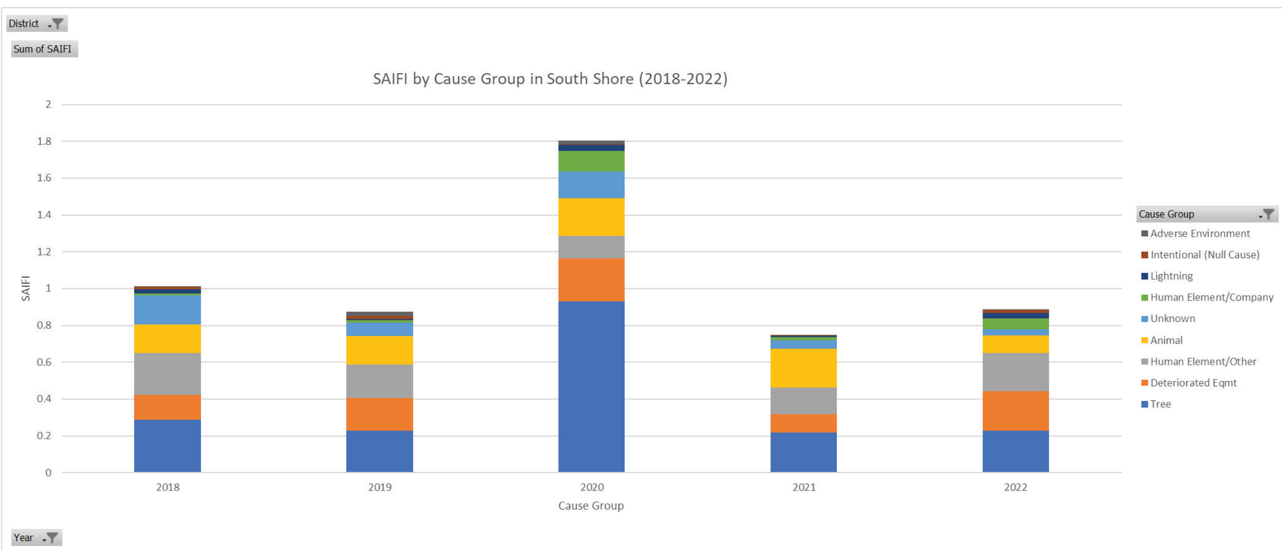
Reliability performance

The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

[29] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

Exhibit 4.115: South Shore Sub-Region Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance





The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company’s regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, the South Shore has been in the first or second quartile for frequency of outages (SAIFI) and has been in the first or second quartile for the past five years for duration (SAIDI).

SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
2nd Quartile	1st Quartile	3rd Quartile	2nd Quartile	2nd Quartile

Sum of SAIDI Medium Quartile				
2018	2019	2020	2021	2022
2nd Quartile	1st Quartile	1st Quartile	2nd Quartile	1st Quartile

Refer to Section 4.3.9 for background on how reliability metrics are calculated.

Resiliency performance

As described in Section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in Section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with EJCs. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the EJCs predominantly fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.116: South Shore Sub-Region Resiliency in EJCs as shown as SAIDI Substation Performance

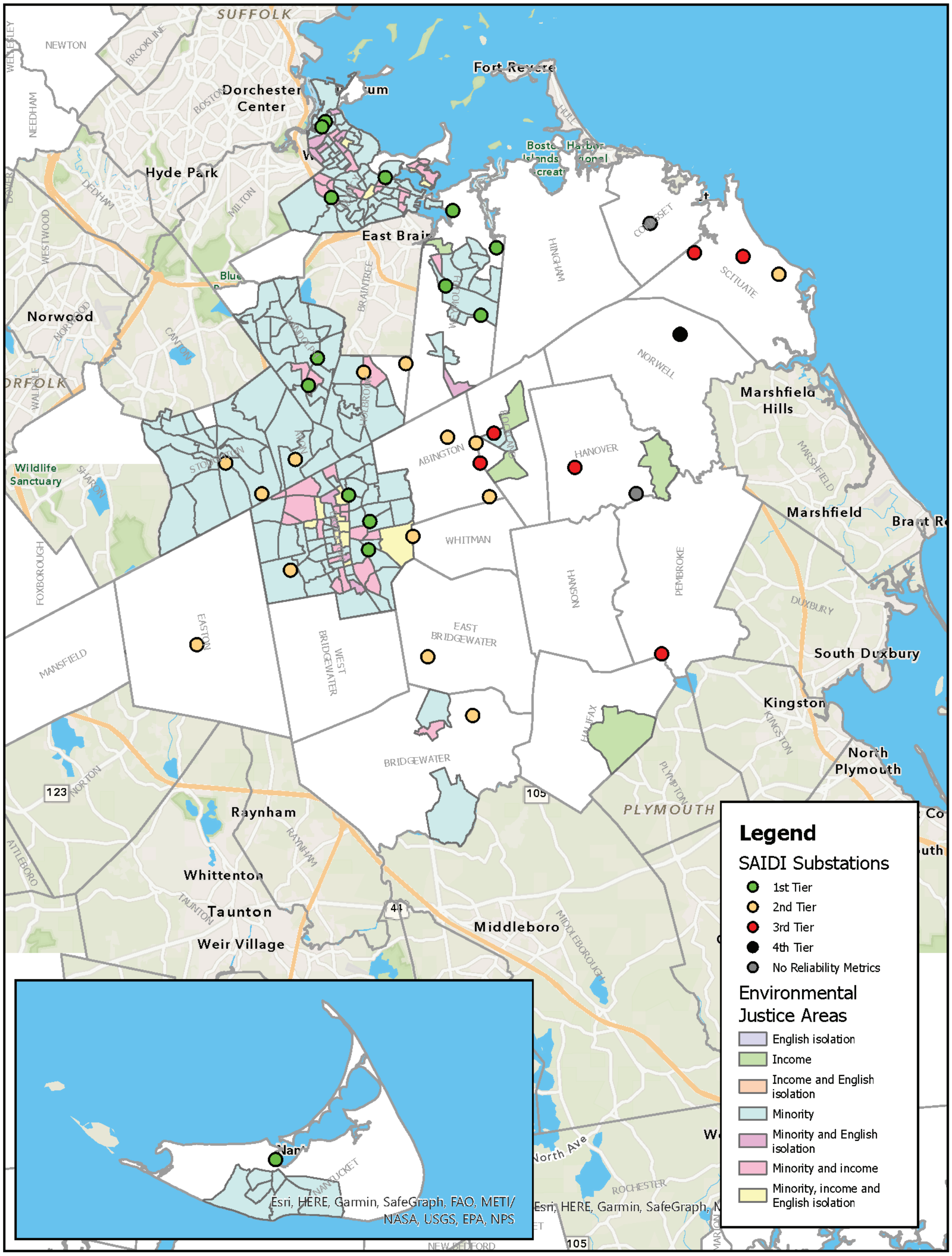
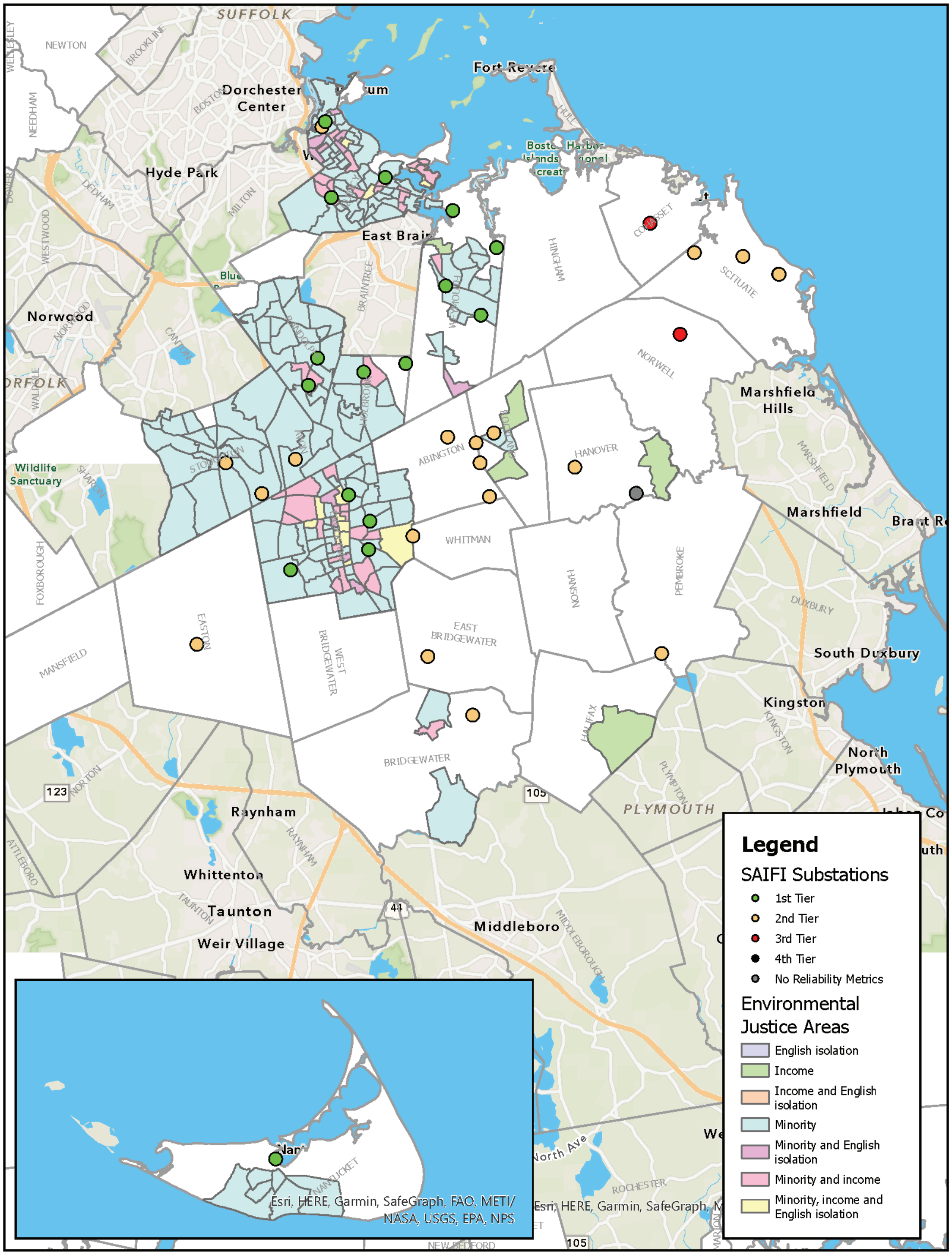


Exhibit 4.117: South Shore Sub-Region Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company's Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.7.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with state requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

There are no noteworthy environmental considerations for the South Shore sub-region except for the island of Nantucket. Nantucket has particular constraints around land scarcity and natural resource conservation. Project-level considerations are taken based on the local environmental considerations.

4.8 Western Sub-Region

The Western sub-region in brief:

Nature of the area: The Western sub-region is overwhelmingly rural, with regional urban centers in North Adams and Northampton.

Exhibit 4.118: Western Sub-Region Network by the Numbers

Description	Value	Unit
Number of Substations	29	Count
Number of Feeders	90	Count
Total Length of Feeders	3,250	Miles
Total Peak Load Served	418	MW
Sub-region Area	1,481	Square Miles
Benefits of EE	613,551	MWh
Heat Pump Adoption	1,971	Count
Charging Ports Installed	135	Count
5-Year Residential Population Growth Projections	0.05%	Percent
5-Year Forecasted Load Growth	12.7%	Percent
Existing Connected Rooftop DER (< 25kW)	79	MW

Context of the region

The Western sub-region is predominantly rural which has a more radial network. There are some more suburban areas in the region, but the network is very constrained in all areas. The Western sub-region has high levels of DERs penetration relative to all other sub-regions due to the large amount of open space compared to other areas of the Commonwealth. Due to growing suburban neighborhoods, an approximate 12.7% load growth is expected in the Western sub-region in the next five years. Additional details can be found in Section 5.

The Western sub-region is served by 29 substations supporting 90 circuits. Because of the way that the networks in the Western area have developed, the Company will need to undertake significant investment to meet the expected load growth. Due to land availability and land prices, this area has seen and continues to see a large number of DER applications interconnecting to the system that was intended to serve a more remote radial type of service.

The Western sub-region has some key characteristics which will drive investment needs in the future.

Exhibit 4.119: Western Sub-Region Key Characteristics that will Drive Future Investment Needs

Network Characteristic	Consequence
The majority of the distribution circuits in the region are 15 kV class circuits, which operate at voltages of 13.2 kV or 13.8 kV. While very few circuits are operated at 4.16 kV at their source, there are many 4.16 kV neighborhoods supplied by pole-mounted transformers that step voltages down to 4.16 kV more locally. This was a common practice in the past when converting circuits from 4.16 kV to 15 kV class voltages, to limit the scope of the conversion by continuing to operate local areas at 4.16 kV.	Areas served by these lower voltages will largely need to be converted to a higher voltage such as 13.2 kV or 13.8 kV in order to meet the significant load growth that is projected across the Commonwealth. Voltage conversions can be costly and complex projects even at this local stepdown level, requiring widescale replacement or upgrade of significant amounts of distribution line facilities.
Population and load density in the Western sub-region leads to average feeder lengths that are 2-3 times the length of the average feeder in other sub-regions to serve approximately the same number of customers. These feeders are predominately overhead construction, through heavily treed areas.	Longer feeders have more exposure to outages, particularly outages due to trees falling over many miles of line exposure. With less dense substation infrastructure and fewer road-side routes available in rural areas, mitigating reliability exposure while accommodating load growth is particularly complex.
Lower historical load levels in the region have led to development of infrastructure with lower capacity. This includes both a sparsity of transmission facilities to supply new substations, and a high proportion of single transformer substations relative to other regions.	Accommodating load growth in the region will require expansion of existing single transformer substations, many of which were not originally designed to accommodate such an expansion, and installing significant new transmission facilities.

There is a high amount of DER penetration relative to load levels within the sub-region.	Many facilities within the sub-region experience power flow "backwards" from the distribution system to the transmission system, particularly during low-load seasons such as spring and fall. At times these backflow levels exceed equipment ratings. Additional DER interconnections in the region that are not offset by increasing electrification demand will require investment to create additional generation hosting capacity.

4.8.1 Maps

The Western sub-region consists of 51 municipalities and comprises the study areas below:

Exhibit 4.120: Western Sub-Region Study Areas and Municipalities

	Study Area	Town
1	Adams/Deerfield	Adams, Charlemont, Cheshire, Clarksburg, Florida, Hancock, Hawley, Heath, Monroe, North Adams, Rowe, Williamstown
2	Barre/Athol	Athol, Barre, Erving, Hardwick, New Braintree, New Salem, Oakham, Orange, Petersham, Phillipston, Royalston, Shutesbury, Ware, Warwick, Wendell
3	Monson/Palmer/Longmeadow	Barre, Belchertown, Brimfield, East Longmeadow, Granby, Hampden, Hardwick, Holland, Monson, New Salem, Palmer, Wales, Ware, Warren, Wilbraham
4	Northampton/southern Berkshire	Alford, Egremont, Goshen, Great Barrington, Lenox, Monterey, Mount Washington, New Marlboro, Northampton, Sheffield, Stockbridge, West Stockbridge, Williamsburg

Exhibit 4.121 below shows the substation locations within the Western sub-region's study areas, indicated with a red dot. Note that not all study areas cleanly follow town lines because they are defined electrically instead of geographically.

Exhibit 4.121: Western Sub-Region Substation Locations and Study Areas

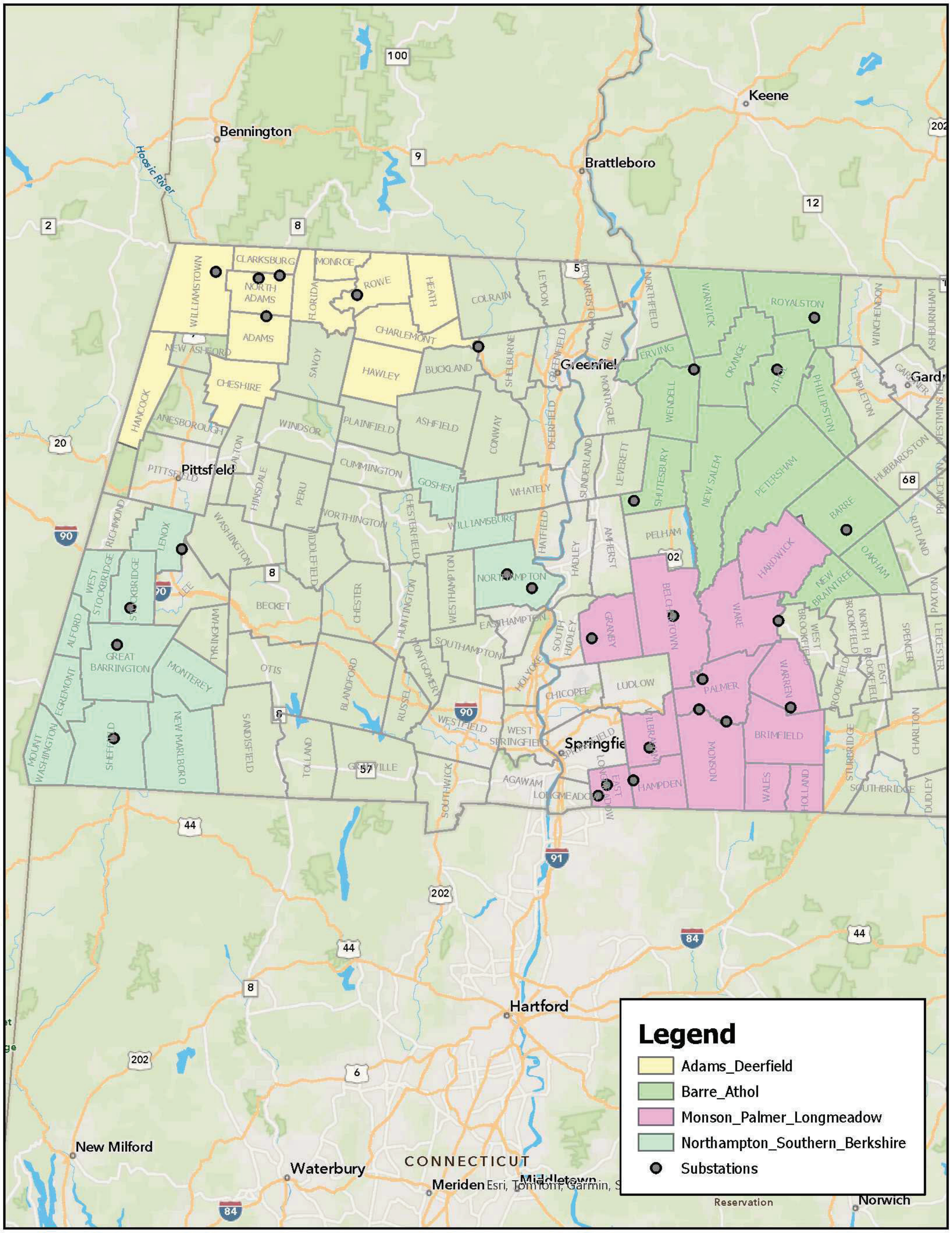
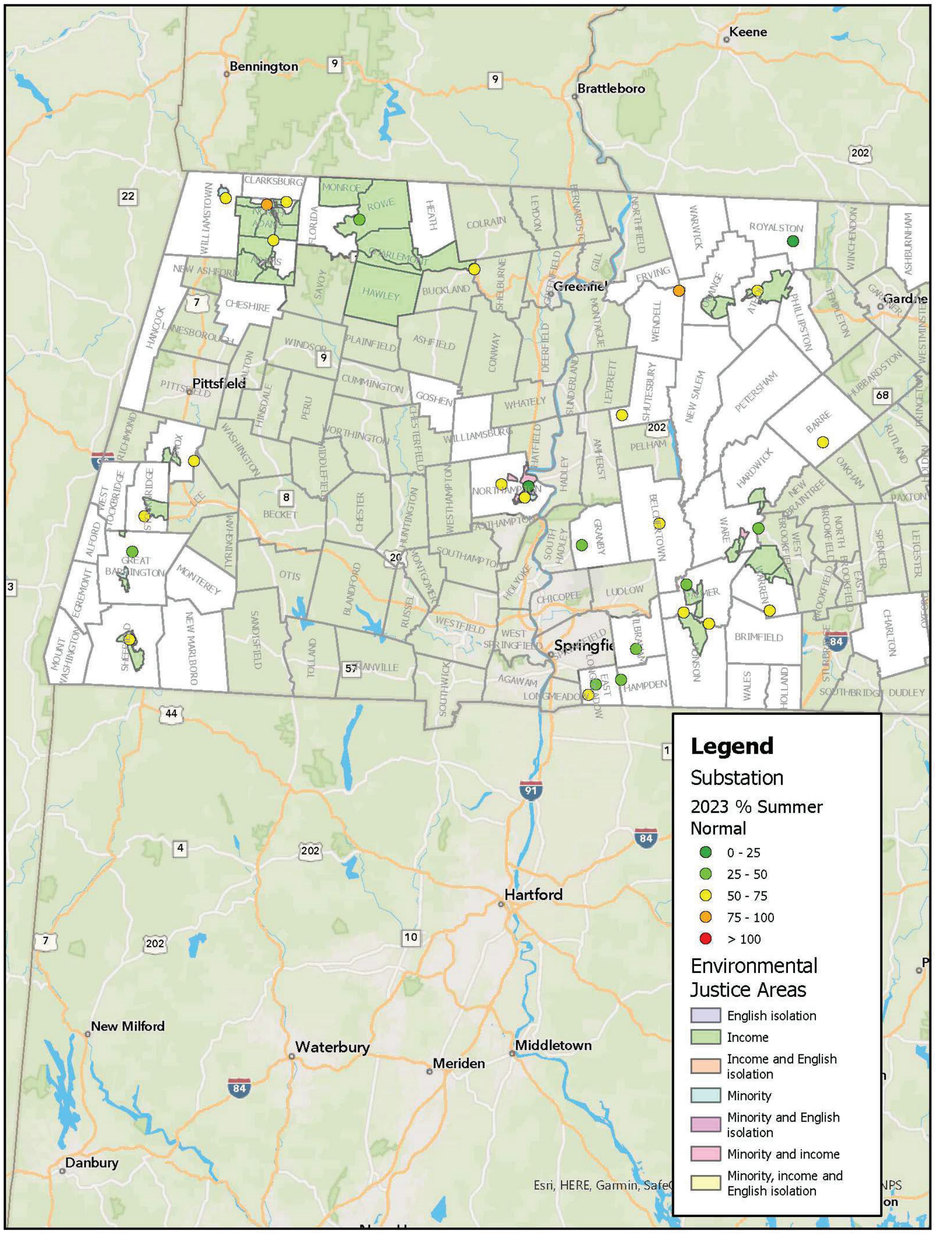


Exhibit 4.122 displays projected 2023 summer normal loading at each substation in the Western region.[30] While no transformers were projected to be loaded over their 100% of summer normal ratings, there are two loaded between 75-100%; this loading level aligns with the Company's Distribution Engineering Planning Criteria but indicates that the transformers are approaching their capacity and significant localized electrification load growth will be difficult to accommodate without major infrastructure development.

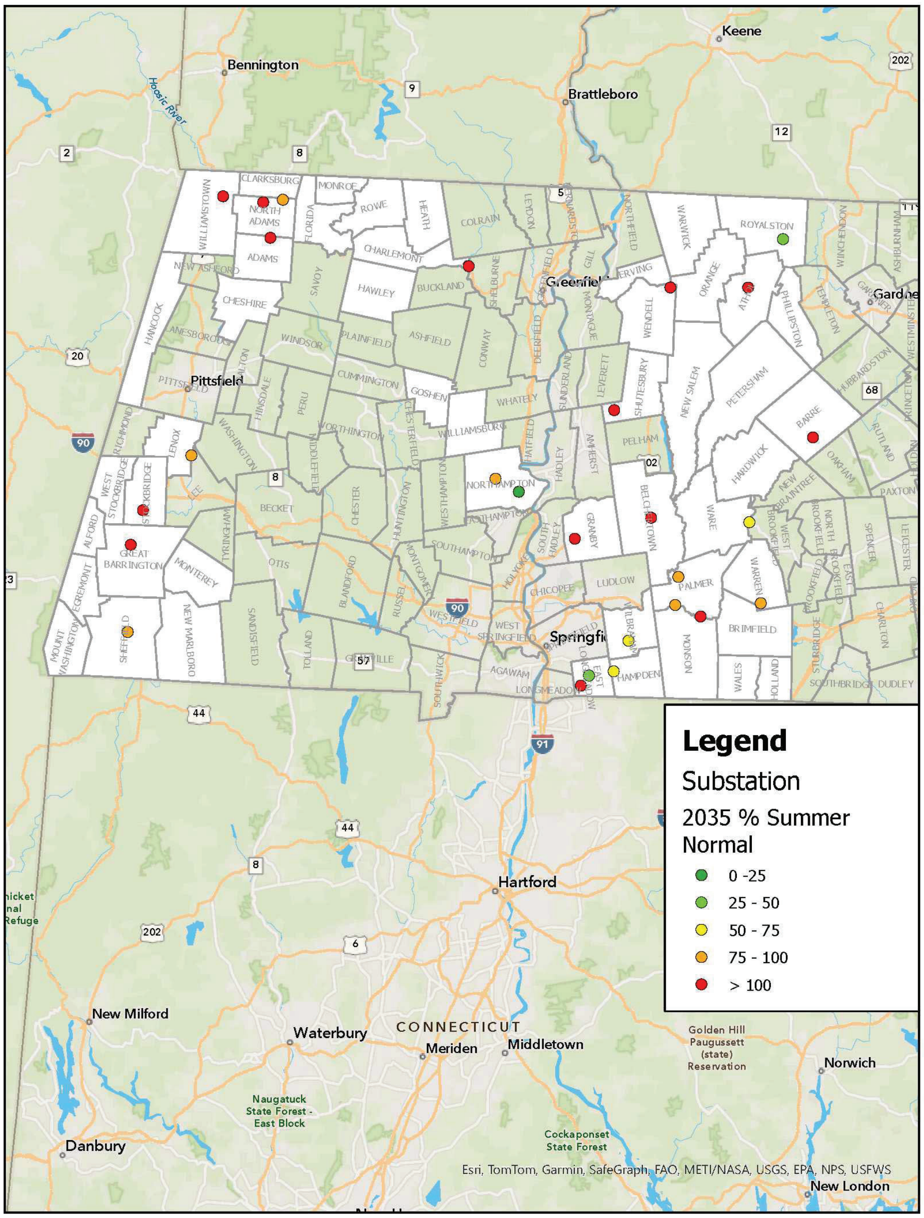
Exhibit 4.122: Western Sub-Region Substation Transformer Loading in 2023



[30] The Company is reporting current loading in terms of the forecast load for 2023. While Summer 2023 has already occurred, as of this filing the annual loading review is still in progress and so updated weather adjusted loads were not available for inclusion.

By 2035, however, this system will be overloaded in several places with the increase in loading on the system if the investments proposed in this Future Grid Plan are not carried out. Exhibit 4.123 below shows where the projected overloads will happen.

Exhibit 4.123: Western Sub-Region Substation Projected Transformer Loading in 2035 if No Investments are Made



4.8.2 Customer Demographics

Exhibit 4.124: Western Sub-Region Customer Demographics

Total Customers	Customer Accounts	Percent of Total
Total Customers (Accounts)*	**121,606**	-
Residential	106,467	88%
Residential – Low Income Rate Participants	*15,509*	-
Business, Commercial, Municipal, or University	15,139	12%

The Company serves a total of 121,606 customers (defined by individual accounts, not the number of people served) – in the Western sub-region. Approximately 88% (106,467) of these customers are residential customers and the other 12% (15,139) are comprised of commercial, municipal, or university customers.

Population growth in this region is forecasted to be considerably lower than the other sub-regions due to historical census data and expected trends in highly rural areas[31].

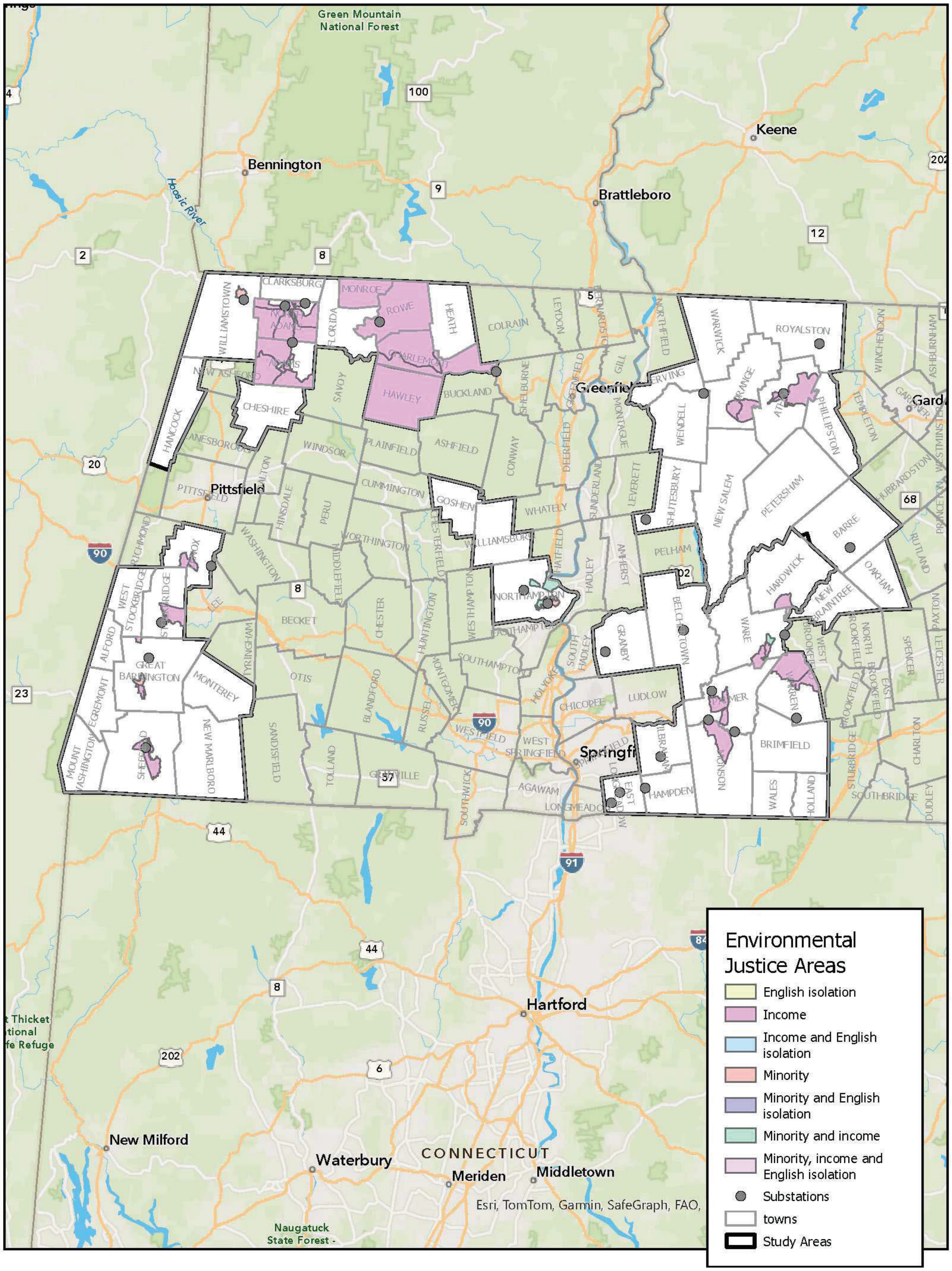
In addition to the Mass Save programs which have benefited customers in the central region, 24 municipalities statewide have been identified for targeted outreach per MA EEAC Equity Working Group plans. Under these outreach plans the Company is specifically working to encourage more Energy Efficiency benefits in low-adoption zones. The municipalities included in the Central region are: North Adams, Palmer, Great Barrington, and Northampton.

The Company recognizes that a significant portion of the Company's customers live in EJCs, which are disbursed throughout the Company's service area. Historically, EJCs have borne the highest energy burdens and been disproportionately impacted by the fossil-based economy. As outlined earlier in Section 3.3, the Company is developing a formal Equity and Environmental Justice Policy and Engagement Framework, as well as complementary policy and framework focused on Indigenous Peoples, which the Company will seek feedback on from those communities prior to finalizing. Please refer to the Appendix for those drafts.

Exhibit 4.125 below is a map that overlays current substation locations with the Commonwealth's Environmental Justice maps, updated in 2022. Exhibit 4.125 below highlights concentrations of substations in many load-dense areas – town centers and other major economic areas with existing industry, or a history of industry. Load density and electric capacity needs are the key drivers to substation density and location. As the load increases, the need for more substations to serve these population centers and expanding rural areas will increase too. Many Environmental Justice Areas have been identified as such by the Commonwealth because they have been historically unduly burdened by infrastructure and related pollution. As discussed in Section 3, the Company is committed to being a trusted partner with all the Company's host communities, including those which contain Environmental Justice Populations, as new infrastructure needs to be built throughout the Commonwealth to reach decarbonization and electrification goals and the associated benefits. Additional infrastructure that has yet to be built per recommendations in this Future Grid Plan can be found in Section 6.

[31] Analysis of data from https://data.census.gov/

Exhibit 4.125: Western Sub-Region Substation Locations in Relation to the Commonwealth's EJCs



4.8.3 Economic Development

The development of the Company's Plan was informed, in part, by the varying levels of readiness within each sub-region. Within the Company's study areas defined in the Future Grid Plan, 14 communities have completed decarbonization plans and 139 are designated as "green communities" under M.G.L. c. 25A §10. In partnership with the Company, the following municipalities have completed a Strategic Energy Management Plan (SEMP): Athol, Beverly, Everett, Gloucester, Lowell, Melrose, Newburyport, and Salem. There are an additional five SEMPs in the development queue.

In the Western sub-region, three communities (North Adams, Athol, and Northampton) have completed decarbonization plans, 38 are designated as green communities, and one community, in partnership with the Company, has completed a SEMP. Over the last decade, the region has focused on reconstructing the North-South "knowledge corridor" and East-West "inland route" rail trail corridors to promote passenger and freight traffic. The FY19-24 CEDS highlighted the region's aspiration to lead the Commonwealth's clean energy transformation, with the specific goals of achieving 600 million kWh of new clean energy generation and a reduction of 3.2 metric tons of GHG. The strategy emphasizes the ongoing challenge posed by the region's fragile infrastructure systems and the need to increase investment levels across the region.

4.8.4 Electrification Growth

Heat Electrification - The Western sub-region has moderate pump adoption compared to the other five sub-regions with about 1,100 units adopted by the end of 2022, of which over 60% are hybrid.

Transport Electrification – There has been steady growth in LDEV sales in the Western sub-region, although with about 3,380 vehicles as of the end of 2022, the Western sub-region has the lowest number of EVs among all sub-regions. Additionally, there are no MHDEVs at present. Since 2019, the Company has installed 135 EV charging ports via their phase I and phase II EV charging programs in the Western sub-region.

4.8.5 DER Adoption (Battery Storage and Solar Photovoltaic)

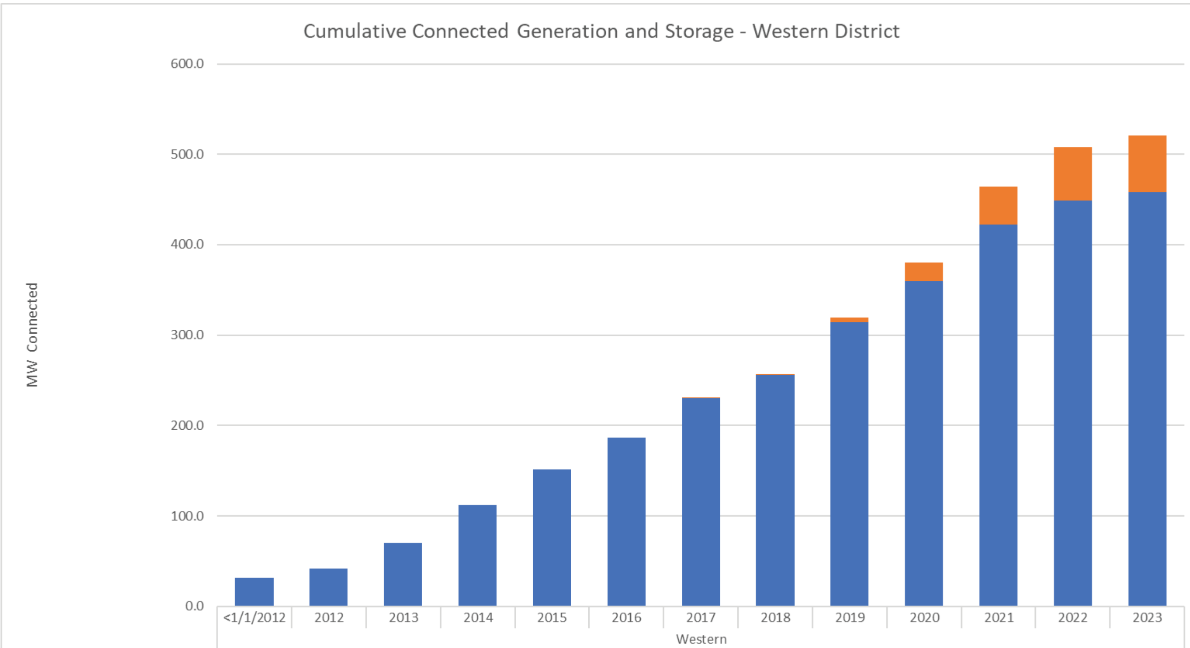
With a total of 521.1 MW of generation connected, the Western sub-region has relatively high DER penetration. Connected DER is predominantly solar, representing 92% of the installed DER capacity in the Western sub-region.

Exhibit 4.126: Western Sub-Region DER Capacity Connected and In Queue

DER Category	Connected Capacity (MW)	Capacity in Queue (MW)
Solar	417.0	167.2
Battery	63.4	253.2
Hydro	1.9	0.2
Wind	9.1	0.0
Miscellaneous	29.8	10.6
Total	**521.1**	**431.2**

Significant levels of DER have been connected in the Western sub-region, predominately in the past decade. Note that in Exhibit 4.127, the 2023 value is reflective of year-to-date interconnections as of July 2023.

Exhibit 4.127: Cumulative Connected Generation and Storage – Western Sub-Region



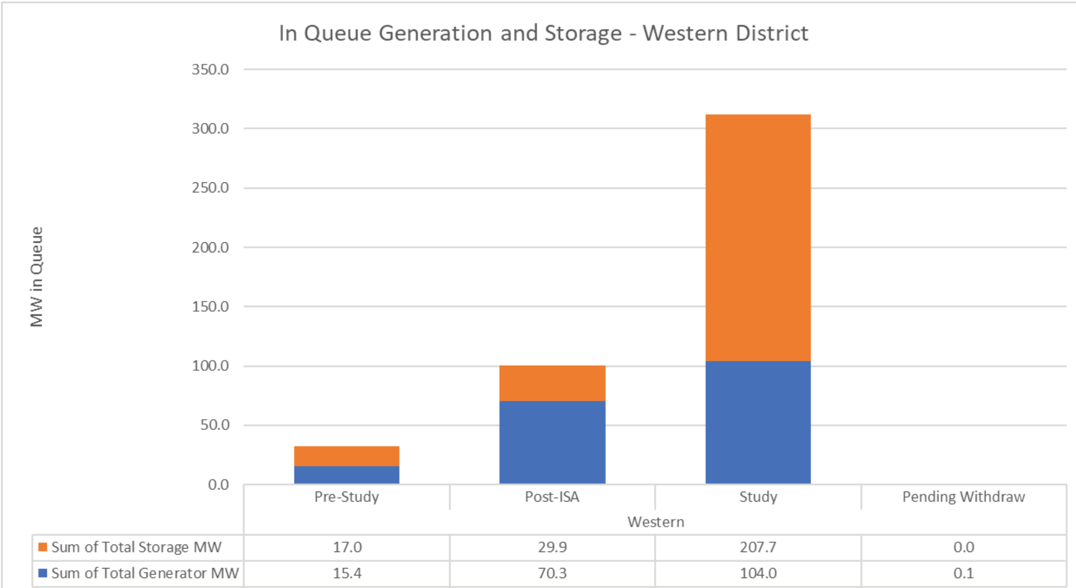
	<1/1/2012	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Sum of Total Storage MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	5.3	21.0	42.0	59.3	63.4
Sum of Total Generator MW	31.8	41.5	69.9	112.3	151.3	186.9	230.5	256.4	313.9	359.3	422.5	448.8	457.8

Exhibit 4.128 contains visibility of the current DER interconnection queue in the Western sub-region. Recent application trends have demonstrated a shift from largely solar PV applications to a split between solar PV and battery storage, with solar PV representing 62% and batteries representing 35% of the current queued DER capacity.

A large majority of the batteries are stand-alone, albeit some are co-located as PV paired with storage. Unlike other forms of DER, which operate solely in a discharge or export capacity, contributing power to the grid, standalone batteries also must charge from the grid. While solar and other forms of DER, excluding batteries, only require there to be sufficient grid *hosting* capacity for their interconnection, batteries require both hosting and load-serving capacity at the location of their interconnection. Therefore, batteries are subject to capacity deficiency (i.e., charge) considerations such as those highlighted in Section 4.8.7 as well as any hosting capacity (i.e., discharge) constraints that may be present.

This significantly increases the complexity of planning and operating the network.

Exhibit 4.128: In Queue Generation and Storage – Western Sub-Region



Combining the 431.2MW in the interconnection queue, and the 521.6MW already connected in the Western sub-sub-region, the total for the area would be 952.8MW if all in-queue projects move forward. While it is unlikely that all will connect, this would be a doubling of interconnected DER in an already constrained area and would therefore require significant infrastructure expansion.

There are CIP proceedings underway in this area under the following dockets:

- Barre Athol (Department Docket No. 23-12)
- Monson Palmer East (Department Docket No. 22-170)
- Shutesbury (Department Docket No. 22-61)

In the Western sub-region, the Company has analysis completed or in progress for group study for the interconnection of DER in the following study areas:[3]

- Monson Palmer Northwest

The proposed DER and system modifications required for the proposed groups have been included in the base case for this Future Grid Plan analysis; should the DER customers in these groups not proceed to interconnection, the investments described will need to be analyzed for the impacts of this attrition and adjusted appropriately. The Company is proposing to apply the CIP cost allocation methodology, process, and Provisional System Planning Provision to group studies that will be finalized and delivered following Department approval of the extension of that methodology.

The high-level benefits of the CIPs to distribution customers include:

- Reliability: the solution proposed to safely and reliably interconnect group study DER, in many cases coincidently, addresses existing or projected system needs. The proposed upgrades, if approved, expedite addressing these reliability concerns. These include:
    - EPS normal configuration thermal loading
    - EPS contingency configuration customer unserved
    - EPS asset conditions
- Enabled electrification: the proposed solutions in some cases also provide thermal capacity beyond the planning horizon and support some loading projects out to 2050.

- Reserved Small DG: the proposed solutions also incorporate a reserved capacity on each study feeder for the small rooftops to interconnect without triggering major EPS upgrades, which typically is a direct benefit to distribution customers.

Note that these areas are in various stages of maturity and the modifications identified below are subject to change pending further analysis through the group study process. Cumulatively, in order to interconnect the 19 MW of DER proposed through the current group studies, the Company anticipates requiring system modifications that include the addition or upgrade of two substation transformers and approximately two miles of distribution line construction, at an estimated cost of $21M.

4.8.6 Grid Services (Demand Response, Smart Inverter Controls, Time-varying Rates)

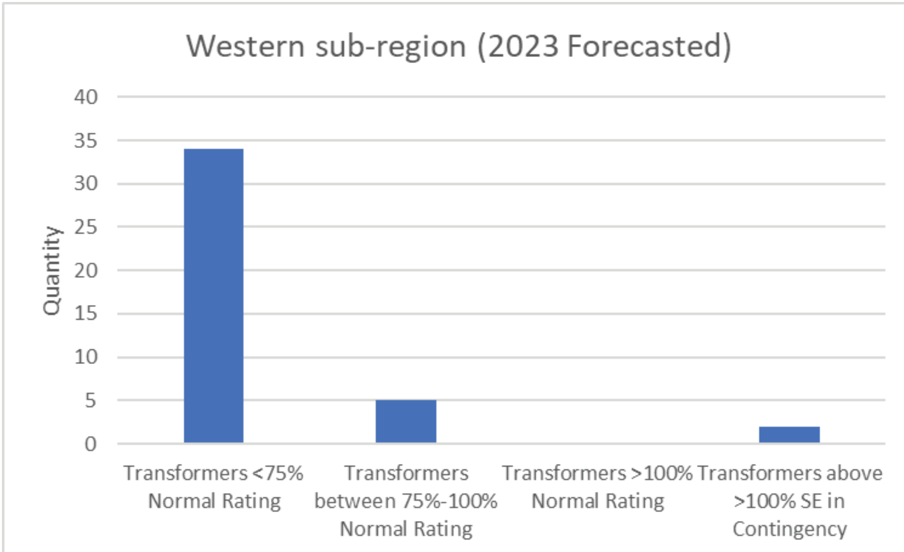
The Company currently offers several grid service participation opportunities to residential and commercial customers through its Demand Response and EV managed charging programs. Customers can earn incentives for curtailing load, pre-cooling with smart thermostats, charging their electric vehicles at optimal times, or shifting energy use with battery storage during peak load periods. As described in sections 6.3, 6.11, and 9.3 and 9.6 the Company is also on a path toward expanding grid services via AMI and time-varying rates, and leveraging DERMS technology investments to offer more dynamic, location-specific grid services as NWA solutions in the future.

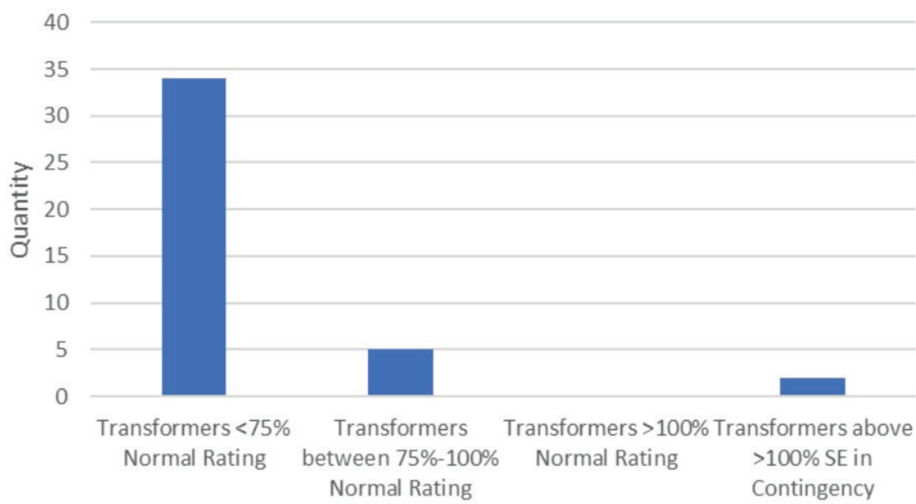
In the Western sub-region, over 2,000 customers currently participate in ConnectedSolutions DR program and help to reduce approximately 19 MW of load on the grid when the overall grid is at peak.

4.8.7 Capacity Deficiency

The exhibits below summarize the asset loading across the Western sub-region in 2023. The 2023 loading profile shows that most assets are loaded below 75% of their normal rating.

Exhibit 4.129: 2023 Forecasted Transformer Loading Profile – Western Sub-Region



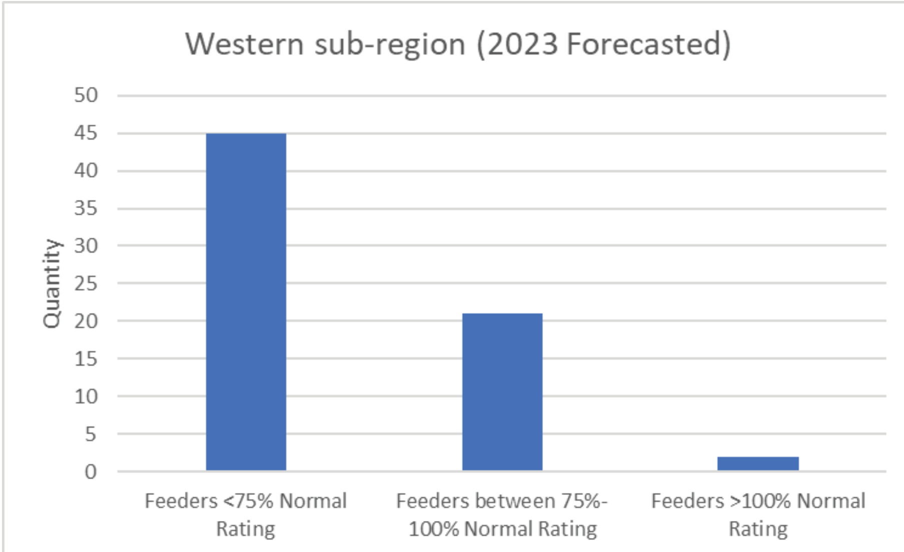


Substation transformer capacity deficiencies exist in the following areas:

Exhibit 4.130: Western Sub-Region Pending DER Generation and Storage In Queue

Study Area	Substation	Capacity Deficiency
Barre-Athol	BARRE 604	Transformers > 100% Emergency Rating in Contingency

Exhibit 4.131: 2023 Forecasted Feeder Loading Profile – Western Sub-Region



Two feeders in the Western sub-region have an identified existing capacity deficiency; this deficiency is being monitored as an anticipated spot load comes into service, and operational mitigations will manage the overload as appropriate. One of the overloaded feeders is a reverse flow overload due to the interconnected DER on the feeder.

The Western sub-region features a 23kV sub-transmission system in the Adams/Deerfield area that supplies most of the study area through the Adams Substation. The Adams Substation serves approximately 70MW of load and supplies three substations which step the voltage down from 23kV to 13kV. The Adams 23kV system has normal and contingency loading concerns that limit the amount of load growth that can be supported by the Adams substation.

The Northampton/South Berkshire study area is primarily supplied by a transmission and sub-transmission network owned by Eversource. The Northampton area is supplied by a combination of 115kV and 13.8kV from the Midway substation. The South Berkshire area is supplied by 23kV supply lines from the Pleasant 16B and Woodland substations. The study area will have normal and contingency loading concerns that limit the amount of load growth that can be supported by the sub-transmission supplies from the Eversource owned network. Infrastructure investments in these areas must consider Eversource as a critical stakeholder.

4.8.8 Aging Infrastructure

This section is only illustrative for completeness of the system, and as such, relevant aging infrastructure investments are defined to be part of “core operations” and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

As energy infrastructure ages, and often consequently, its condition worsens, the risk of equipment failure increases and the reliability of operation decreases. The age of infrastructure is an important consideration when assessing the condition of assets and in efforts to meet the future demands of the network. However, asset replacement is driven primarily by asset condition rather than time of life. The Company’s approach to maintenance has moved from a time-based approach to risk and condition based as a result of digitizing information and having real-time data. Substations and distribution lines are surveyed regularly to assess asset health and to make recommendations for replacement.

Assets are rated based on a range of criteria to assess their health, which drives asset condition replacement projects. Standard maintenance and regular testing (e.g., inspecting and replacing subcomponents of a circuit breaker) can enhance reliability and extend the life of specific assets. Often, assets exceed their life expectancy if their condition and risk profile allow it, enabling the Company to maximize the value of assets while maintaining network reliability.

Additionally, as the Company moves towards modernizing and standardizing the grid and/or substations, existing equipment may need to be modified or replaced in order to digitize current methods. It is important the Company remains diligent in improving its infrastructure with new technologies and remains environmentally focused. (e.g., changing substation support structure design from aluminum to steel due to efficiency and decarbonization).

Exhibit 4.132 below shows the metalclad age profile in the Western sub-region.

Exhibit 4.132: The Metalclad Age Profile – Western Sub-Region

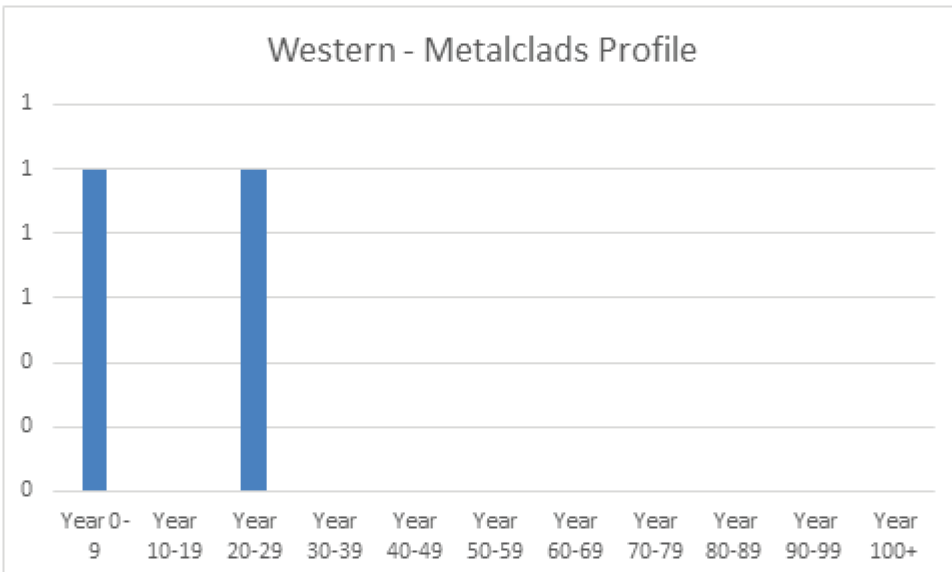


Exhibit 4.133 below shows the transformer age profile in the Western sub-region.

Exhibit 4.133: Substation Transformer Age Profile – Western Sub-Region

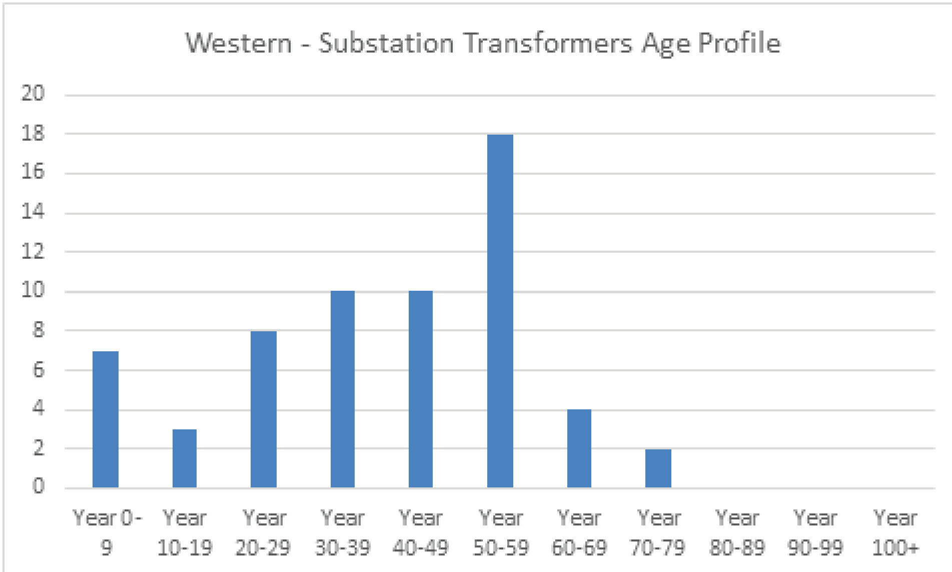


Exhibit 4.134 below shows the distribution pole age profile in the Western sub-region.

Exhibit 4.134: Distribution Pole Age Profile – Western Sub-Region

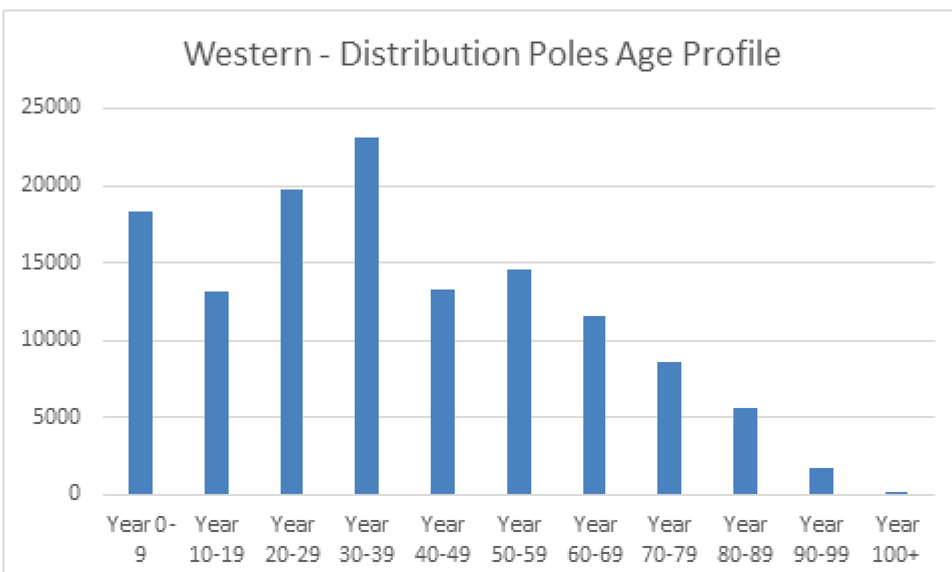
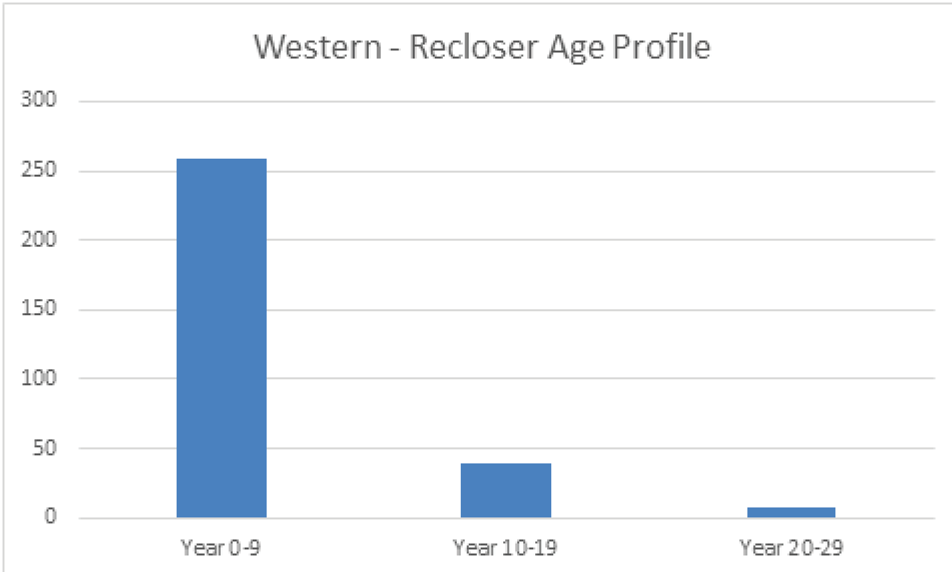


Exhibit 4.135 below shows the recloser age profile in the Western sub-region.

Exhibit 4.135: Recloser Age Profile – Western Sub-Region



4.8.9 Reliability and resilience

This Section will describe how the Company reports reliability and what the current reliability metrics are for this given sub-region. Additional information can be found in the EDCs' Service Quality Guidelines.[32] This Section is only illustrative for completeness of the system, and as such, relevant reliability investments are defined to be part of "core operations" and additional funding is not proposed in this plan. The investments proposed in this Future Grid Plan are driven by load growth and the need to increase system capacity.

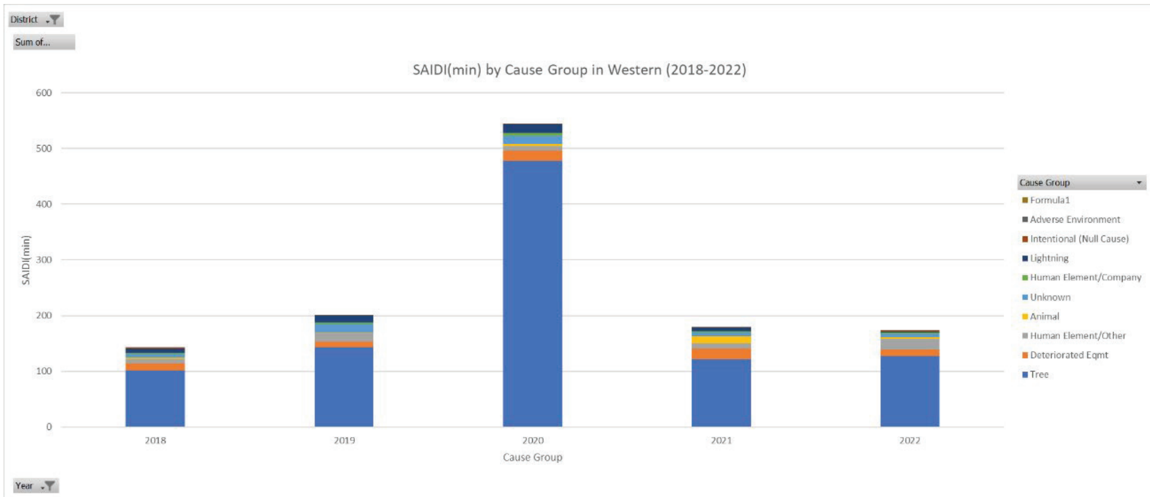
Refer to Section 4.3.9 for background on reliability metrics and performance.

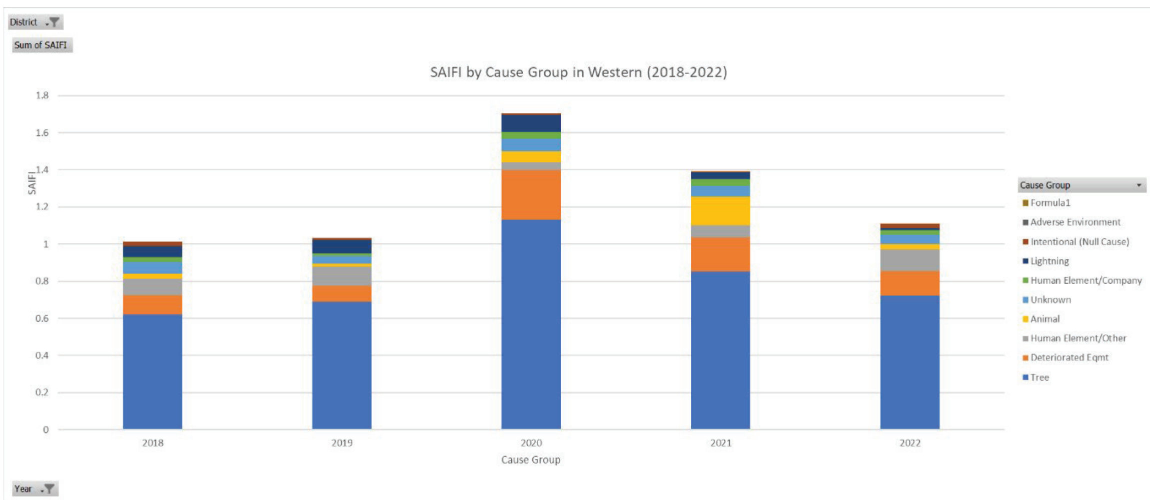
Reliability performance

The exhibits below show the reliability performance of the sub-region in terms of duration (SAIDI) and frequency (SAIFI) of outages. The data in these Exhibits excludes major events, consistent with the Company's regulatory reporting criteria and call out leading causes of blue-sky outages for the region. Tree-related events caused most outages across this sub-region, in terms of duration and frequency.

[32] D.P.U. 12-120, D.P.U. 12-120-D, Attachment A.

Exhibit 4.136: Western Leading Causes of Blue-Sky Outages and SAIDI and SAIFI Reliability Performance





The IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366) was developed to facilitate uniformity in distribution service reliability indices and to aid in consistent reporting practices related to distribution systems, substations, circuits, and defined regions. While this methodology differs from the criteria applied to the Company's regulatory reliability reporting obligations, this approach was utilized to demonstrate the performance of the Company's distinct sub-regions as compared to similar size utilities responding to the survey (>100,000 - <1,000,000 customers). The benchmarking analysis showed that for four out of the last five years, Western has been in the second or third quartile for frequency of outages (SAIFI) and has been in the second or third quartile for the past five years for duration (SAIDI).

SAIFI Quartile by Calendar Year				
2018	2019	2020	2021	2022
3rd Quartile	2nd Quartile	3rd Quartile	4th Quartile	3rd Quartile

Sum of SAIDI Medium Quartile				
2018	2019	2020	2021	2022
3rd Quartile	2nd Quartile	3rd Quartile	3rd Quartile	3rd Quartile

Refer to Section 4.3.9 for background on how reliability metrics are calculated.

Resiliency performance

As described in Section 4.3.9, outage impacts from major events are traditionally excluded from reliability reporting, as described above. The Company calculated “all-in” SAIDI and SAIFI indices across its service territory to facilitate comparison of the resiliency and reliability challenges experienced in each sub-region relative to the others. This comparison highlights areas where emerging resiliency challenges have been experienced in the past five years. The methodologies that went into these calculations are described in Section 4.3.9. Substations may have no reliability data for several reasons, including no recorded events over the time period or if they do not directly serve load to customers.

The following maps illustrate the substation resiliency of this sub-region overlaid with EJCs. The exhibits below show the Company’s distribution substation locations within the given sub-region overlaid with Environmental Justice Areas. Each distribution substation is color-coded indicating its 5-year historical SAIDI or SAIFI performance relative to the Company’s entire population of substations. A greater density of distribution substations typically results in shorter distribution feeders with less outage exposure and increased numbers of feeder ties, resulting in better overall reliability. As can be seen in each of these Exhibits, substations in the Environmental Justice areas fall within the top first and second quartile of SAIDI and SAIFI performance relative to the entire population of the Company’s distribution substations.

Exhibit 4.137: Resiliency in EJCs as shown as SAIDI Substation Performance

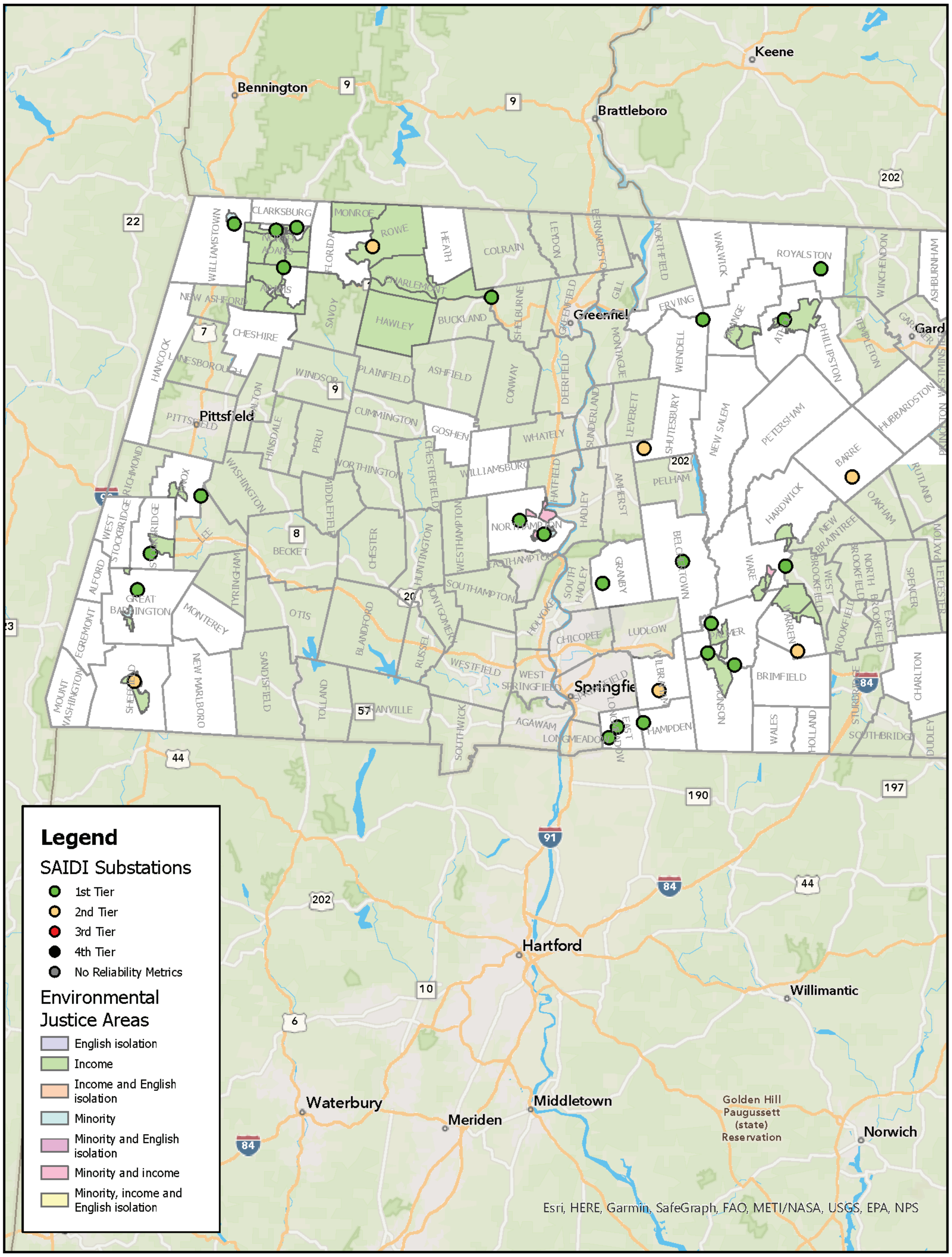
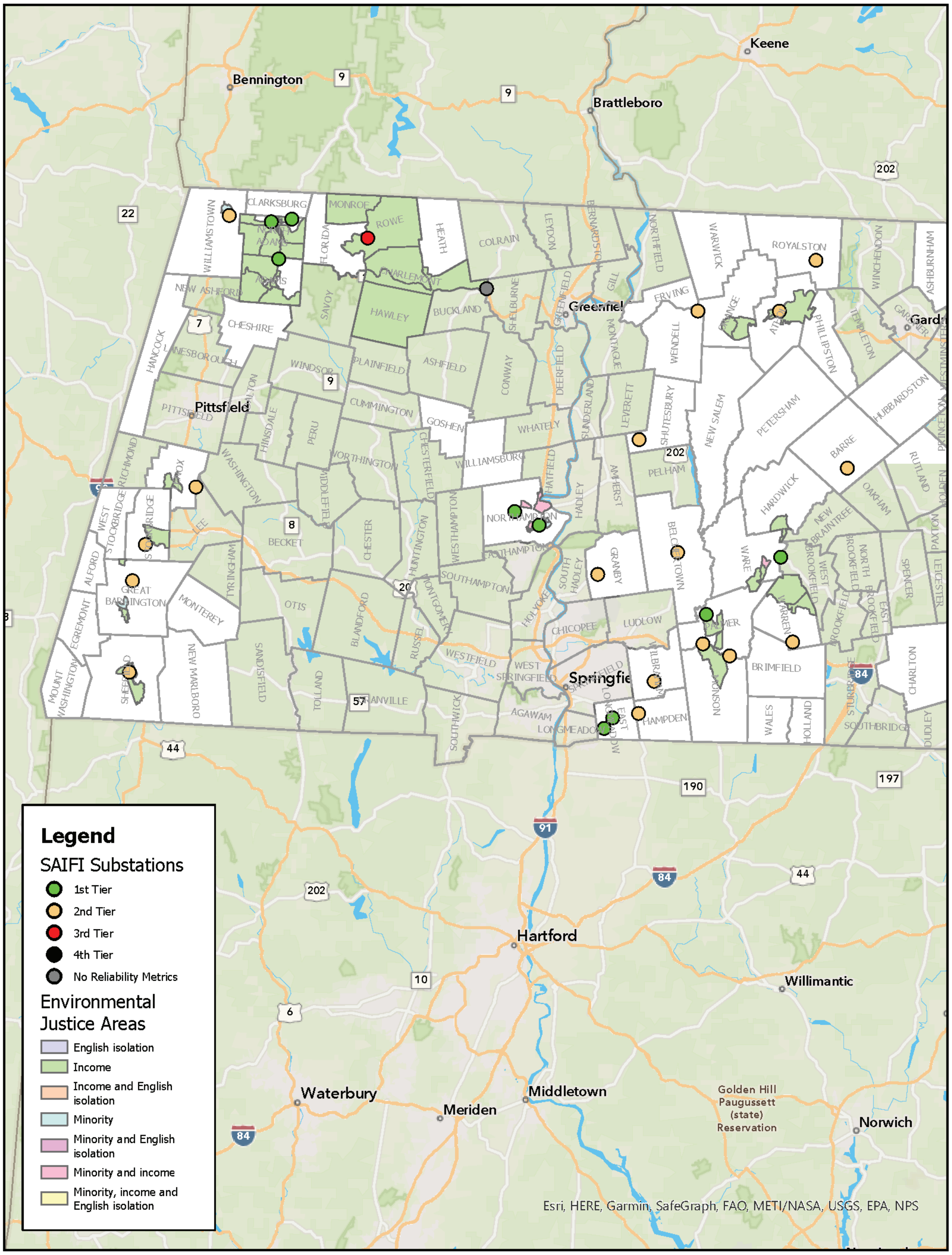


Exhibit 4.138: Resiliency in EJCs as shown as SAIFI Substation Performance



When looking at the 5-year performance, 2020 was particularly a bad year as the Company experienced 18 storm events that were not classified as major events. The impact of each event added together reflects the bad reliability performance at the system level. Also worth noting was that 2018 and 2021 were bad years of performance for the eastern part of the Company’s

Commonwealth service territory given three back-to-back storms occurring in early 2018 and a Nor'easter occurring in October 2021. As a result, substations in the fourth quartile of SAIDI/SAIFI performance can be seen in South Shore, Southeast and Merrimack Valley region maps.

4.8.10 Siting and Permitting

Energy infrastructure siting and permitting processes are generally consistent across the Commonwealth; therefore, siting and permitting challenges do not vary significantly by region. When projects require considerable underground transmission work, the EFSB review process is triggered to ensure the work is in compliance with state requirements. This EFSB review process is intended to take twelve months (see G.L. c. 164, Section 69J); however, the review timeline for recently submitted transmission line projects is trending toward 30 to 36 months.

Environmentally, the largest differences are at a municipal level rather than regionally. At the project-level, Conservation Commission impacts uniformly across the Commonwealth but there is a high degree of variability town to town and year to year, which makes it challenging to generalize regionally.

There are no noteworthy environmental considerations for this sub-region. Project-level considerations are taken based on the local environmental considerations.

4.9 Technology Platforms that the Company Has in Place Today

To operate, manage and control the network for the benefit of customers the Company uses a range of technology and communication platforms. Many of these systems were designed to operate a simpler network and need to be upgraded to meet the needs of the clean energy transition.

This section will briefly highlight several of the technology platforms that are in place today, which are discussed in the following sub-categories.

1. **Network management and communications** includes the technologies used to communicate with, monitor and control assets on the network and to manage and respond to grid outages and abnormal system conditions.
2. **Metering and billing systems** includes the technologies used to measure customer energy usage on the grid and issue accurate bills based on those meter reads.
3. **Customer portals** includes the customer-facing and internal systems leveraged today to manage customer programs such as those related to Energy Efficiency, EVs, and new customer interconnections.
4. **Data** includes the type of data that the Company's network planning and operations and customers have access to, as well as the ability to manage, integrate, and operationalize that data to transform how the grid is operated and planned.
5. **Asset planning, management, and work execution** includes the systems that the Company uses to support grid planning and design, construction and capital deployment, and regular system maintenance and field operations.
6. **Security** includes measures in place to ensure the security of technology systems from potential cyber threats and attacks.

Network management and communications

- Energy management system: The Company for several years has leveraged a centralized Energy Management System (EMS), which provides remote interval monitoring and control for a variety of substation and circuit equipment on both the transmission and distribution system for assets where real-time telemetering has been installed. The tool is relied on heavily by control room operators in the Company's distribution and transmission control centers to provide the best available "real-time" feeds of system conditions. While the EMS includes many distribution network assets, the EMS is primarily designed around transmission use cases. For instance, the EMS performs balanced load flow analysis for the transmission system, though it is not capable of implementing load flow analysis for the unbalanced systems (i.e., single phase systems) that comprise the majority of the distribution network.

- Outage Management System (OMS): In addition to EMS, the Company has utilized an OMS to manage calls and outages. OMS tightly integrates with the call center to provide timely, accurate and customer-specific outage information. OMS also takes these calls and aggregates them on a connected network model of the distribution grid and makes outage predictions to the next level interruptible device to assist in routing crews for response and repair. OMS tracks customer estimated time of restoration, crew assignment and arrival details and outage cause and condition information to supply other downstream reporting and communications.
- Communications: The Company utilizes a combination of private telecom networks and leased wired and wireless circuits and services to meet its mission-critical communications needs such as corporate enterprise functions, teleprotection, Supervisory Control and Data Acquisition (SCADA) communications, physical security required at facilities, grid edge devices, off-site data center connectivity, and Company facility interconnections. These networks are also used to support telemetered communications to larger scale DER (500 kw+) based on current interconnection requirements. The telecom backbone consists of private fiber optic and high-capacity microwave networks. While the existing communications network has supported legacy grid data requirements, it must be upgraded and expanded to support future grid modernization efforts and enable greater reliability, control, monitoring, and security of the assets. In particular, as will be discussed in Section 6, the existing communications network is not fit for purpose for the envisioned future intelligent network operation that involves more dynamic and interactive network management, particularly as DER adoption expands and creates new opportunities to better integrate customer devices into grid operations.

Metering and billing systems

- The Company's meters today are part of an Automated Meter Reading (AMR) system. Deployed in the early 2000s to replace manual meter reading processes, this technology sends a radio signal to a fleet of service vans as they drive by to collect monthly meter reads. The AMR technology contains core features that the Company relies on for identifying customer load, issuing accurate customer bills based on their electricity consumption, and managing customer connections to the Company's infrastructure. The meters function like an odometer in a car, keeping a total tally of net energy consumption on a monthly basis. However, the meters do not have the functionality to collect interval meter reads (i.e., hourly, or sub-hourly energy usage) and support TVR, provide customers with detailed energy insights on the devices in their homes and businesses, or automatically notify the Company's control centers of an outage. Similarly, the Company's billing systems are designed to collect and issue bills based on monthly volumetric energy usage (i.e., how much total energy did I consume this month?), and do not have the functionality today to support TVR. The Company has also received approval to install AMI which is discussed in more detail in Section 6.

Customer portals

- Interconnection portals. The Company has a series of related Salesforce-based customer portals (at different states of maturity) enabling trade partners (e.g., electricians, plumbers, solar installers) to login and submit application materials, check statuses, receive automated email notifications, and correspond directly with employees regarding generation, storage, electric load, and gas connection requests as well as EV incentive program requests. Once a trade partner has submitted an application, the Company's billing customers (and other application stakeholders identified by the trade partner) are able to check statuses, receive automated email notifications, and use the Contact Us form to also correspond with employees about their applications as well as DER billing and incentive program requests after the connection is completed.
- Demand side management program management. Today, the Company utilizes a Demand Side Management system called InDemand to fulfill and deliver on customer requests for clean energy products and programs. This program was originally designed to support implementation of the Company's Energy Efficiency programs. However, with the rapid growth of clean energy, this platform has become antiquated and led to inefficient manual processes, lack of data uniformity and poor customer/trade partner/employee experience. A new platform (Clean Energy 2.0) is in development to greatly improve upon this portal, which will be described in Section 6.

Data

Data is the foundation of much of what the Company does as a utility, including planning, network management and operations. Maintaining and improving interoperability among different software systems to allow diverse datasets to be merged or aggregated in meaningful ways can support better customer, operations, and business outcomes. Historically, the Company's network operation, planning, and customer empowerment have been somewhat limited by data availability. This is changing considerably with, for instance, expansion of feeder monitoring, deployment of ADMS, and new advanced metering systems. The ability to leverage data as a resource to plan and operate a more intelligent grid and create meaningful and valuable opportunities for customers requires continuous investment in data management.

Asset planning, management, and work execution

System planning leverages the CYMDIST software which is used to model and run analyses on the Company's distribution system and the Siemens PTI PSS/e load flow program. ASPEN RDB for Distribution Equipment serves as the centralized repository to record electric distribution device settings information. For asset management, Geographic Information System (GIS) is a technology that combines the power of maps with the function of a database. The Company utilizes GIS as its authoritative source for distribution asset information and as designed network configuration (i.e., "connected model"). GIS information is utilized in several business processes including distribution system project design, load flow modeling, outage management, and analysis models. Cascade is the software application that serves as the asset repository for substation equipment. Maintenance and inspection records are stored in Cascade, which drives the condition-based maintenance programs for substation equipment. STORMS is the foundational work order creation and management system employed by all Electric Line (Tx and Dx) business functions. The platform accepts data inputs from a multitude of different business and IT-owned systems today and transforms this information into dispatchable work orders that field crews use to complete job tasks, ranging from repairing a leaning pole to triggering the design process for replacing an entire feeder.

Security

The protection of both physical and cyber assets is fundamentally important for the Company with its ownership and management of Critical Energy Infrastructure. Examples of existing physical security measures include fences and security cameras, and cybersecurity measures include ubiquitous two factor authentication, next generation firewalls, data loss prevention and intrusion detection. With the shift to digitalization and the integration of telecommunications-based systems, security becomes increasingly important, and these demands continue to grow.

Section 5

5- and 10-Year Electric Demand Forecast

This section describes the methodology and details of the 5- and 10-year electric demand forecasts that underly the proposed Future Grid infrastructure investments.

Key Take-Aways

- The Company uses a robust approach, based on industry best practice, to develop demand forecasts that consider underlying economic and demographic drivers of customer demand as well as increasingly important clean energy policy drivers--namely, energy efficiency, demand response, solar PV, energy storage, EV charging, and heat electrification.
- The 5- and 10-year demand forecasts align with the Commonwealth's ambitious clean energy and GHG emission reductions goals for 2030, modeling acceleration in adoption of EVs and EHPs and expansion of solar, energy storage, and other DER.
- The Company and its customers face an inflection point where 15 years of relatively flat demand will give way to annual peak load that expected to grow by 8% by 2029 and 26%by 2034 relative to 2022 levels--even after accounting for the offsetting impact of energy efficiency, demand response, solar PV, and energy storage—as policy-driven heat and transportation electrification accelerate in the Commonwealth.
- Given the critical role that the demand forecast plays in determining the need for infrastructure investments in the Future Grid Plan, the Company routinely benchmarks its forecast by comparing to independent forecasts from peer EDCs and the Commonwealth.

5.0 5- and 10-Year Electric Demand Forecast

What is demand forecasting and why is it important?

Electric demand, also referred to as load, is the amount of electrical power required at any given time to meet the needs of consumers, businesses, and industries. Electric demand is dynamic and can vary throughout the day, week, and year. Demand is typically highest at temperature extremes (hot or cold), when heating or cooling needs are highest. Peak demand refers to the period of time when demand is highest during the year and is a critical metric for planning electric network infrastructure, as the grid must have enough capacity to serve peak demand.

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and provides system planners with information to prioritize and focus their efforts. These forecasts are an important tool to meet the Commonwealth's climate goals, as they will ensure that the Company is prepared to handle expected increases in load from electrification. This Section focuses on near-term 5- to 10- year forecasts, with investments proposed by these forecasts outlined in Section 6. Section 8 will discuss long-term forecasts from 2035 to 2050.

5.1 5- and 10-Year Electric Demand Forecast at the EDC Territory Level

Summary

The demand forecast demonstrates that the Company is at an inflection point in electricity usage. Peak demand for electricity has remained flat over the last 15 years because any load growth was offset by the Company's nation-leading energy efficiency, demand response, and solar PV programs.[1] While these programs will continue to offset demand, the Commonwealth's decarbonization goals require immediate increased electrification of transportation and heating – which will cause forecasted load to increase by 8% in 2029 and 26% by 2034 relative to 2022 levels. Variability in load growth by subregion is discussed later in this Section.

Methodology overview

The Company uses an econometric modeling approach to generate forecasts of peak demand for its Massachusetts service territory, consisting of two electric distribution companies: Massachusetts Electric Company (MECO) and Nantucket Electric Company (Nantucket). Each peak demand model is developed based on deconstructing past load and the impacts of distributed energy resources (DERs) and modeling each component separately; for the purposes of forecasting, DERs are defined to include demand response (DR), energy efficiency (EE), photovoltaics (PV), energy storage systems (ESS), electric heat pumps (EHP), and electric vehicles (EV). The load forecasts are generated from the "reconstructed" data set.

The 5- and 10- Year Forecasts presented in this Section illustrate a single scenario based on the goals set by the Commonwealth as they require immediate action by the Company. However, the Company did generate scenario sensitivities for the 5- and 10- Year Forecast, which were not considered as part of the plan, the details of which can be found in the Appendix. The longer-term 2050 Electric Demand Assessment in Section 8 presents base, high, and low sensitivities around different technology or policy scenarios due to greater uncertainty in the long

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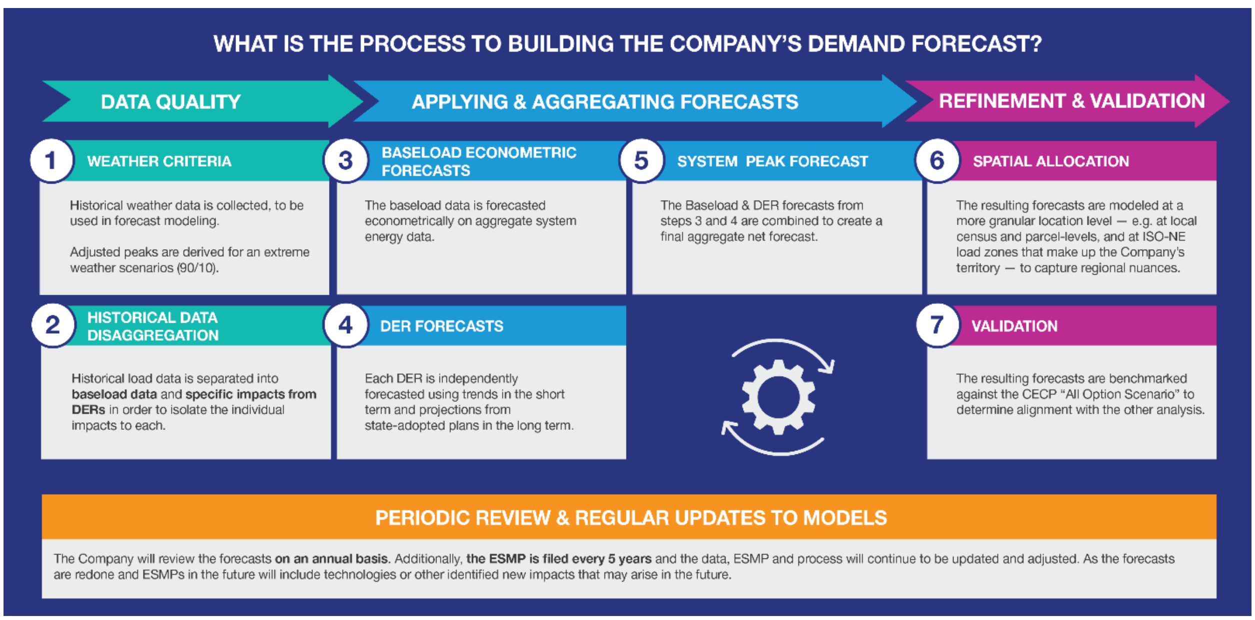
[1] See Section 6 for a discussion of how an increased focus on DR can help reduce, but not eliminate, the need for new infrastructure investment.

run. The full forecast and underlying analysis, both near and long-term, can be referenced in Appendix 9A: Detailed reports on National Grid's Load Forecasting.

The Commonwealth released several pathways over time in which the Commonwealth's decarbonization goals can be achieved and the Company's forecast is primarily based on two Benchmark / Preferred pathways the Commonwealth defined[2]. The **All Options Pathway** is a benchmark pathway that is defined in the Massachusetts 2050 Decarbonization Roadmap. It optimizes for least cost approaches to achieve deep decarbonization. This pathway results in a high degree of building efficiency and electrification and DG penetration. The **Phased Pathway** is a preferred pathway defined in the Massachusetts 2025 and 2030 Clean Energy and Climate Plan (CECP 2025 and 2030). It targets a similar long-term building electrification goal but updates the modeling to consider the electrification of building will be "phased-in" over the next three decades. Thus, it presents both near-term and long-term benefits. Within the Company's illustrated scenario, DERs are benchmarked against these two Benchmark/Preferred Pathways: The EHP forecast aligns with the Phased Pathway. EV adoption is aligned with the adopted California Clean Car rule and Clean Truck rule and meets both pathways. The PV forecast aligns with the All Options Pathway. Finally, ESS forecast lands in-between the All Options Pathway and the Phased Pathway.

The Company's demand forecasting methodology is illustrated in Exhibit 5.1.

Exhibit 5.1: Illustration of Demand Forecasting Methodology



[2] The "Phased" Scenario is a refinement of the "All Options" Pathway with a focus on residential space heating. The "Phased" approach was used as the basis for the CECP's emissions targets and the lowest cost scenario that was modeled. (Massachusetts Clean Energy and Climate Plan for 2025 and 2030, Published June 30, 2022 - https://www.evolved.energy/post/massachusetts-clean-energy-and-climate-plan).

1. **Weather design criteria:** In the first step, the Company analyzes historical weather to determine the weather design criteria. Electric infrastructure needs to be able to reliably provide power in the most extreme conditions – the hottest days in the summer and the coldest days in the winter. The peak demand forecast is therefore calibrated to peaks that occur under extreme temperatures – the 90th percentile. For the summer, this means a design temperature such that the hottest day of the year will exceed it only once every 10 years, on average. In the winter, the coldest day of the year will be colder than the design temperature only once every ten years, on average.
2. **Historical Data Disaggregation:** In this step, the Company disaggregates the historical demand data to separate out historical baseload demand and the historical impact of DERs. Historical demand that the Company has observed has been embedded in its underlying customer energy requirements (referred to here as baseload), as well as the effects of DERs. Over the last 15 years, net demand (i.e., demand that is actually measured) has been flat to declining because the impacts of EE, DR, and PV have offset underlying customer demand growth from new customers and economic growth. If only net demand were modeled, as opposed to the separate effects of baseload and DERs, the Company's modeling would miss the nuances of the effects of baseload and the various DERs, and the Company would be less able to project the effects on net demand of changes in customer growth or DER penetration going forward. Instead, the Company disaggregates historical baseload and DERs and forecasts them each separately, then recombines them to get a single net load forecast.
3. **Baseload Econometric Forecasts:** The underlying customer energy requirements, or baseload, are projected using an econometric forecast. This forecast is developed by looking at the historical trends and relationships between historical baseload and macro-economic, demographic, and pricing variables. These historical relationships are then used in conjunction with expectations for future changes (e.g., projected customer growth, expected demographic changes) to forecast future demand. Customer counts and use-per-customer are forecasted separately to disaggregate their effects – for example residential customer counts may increase due to new construction projects, but residential use-per-customer may be flat-to-declining due to energy efficiency. Forecasting of customer count and use-per-customer is done separately for residential, commercial, and industrial customers since each sectors' growth rates are driven by different factors and may be best reflected by different macroeconomics/demographics. For example, residential customer count is most tightly correlated with the number of households, while commercial use-per-customer is best correlated with gross state product, reflecting overall economic strength. The Company obtains macro-economic historical and forecast data from Moody's Analytics at the county and metro-area level.
4. **DER Forecasts:** Each DER is independently forecasted. In the short-run, forecasts for DERs are consistent with current trends, policies, and programs. However, the outer-year DER forecasts align with the Commonwealth's relevant clean energy goals. The DER forecasts align with the preferred State decarbonization pathway, which the Company models based on the "All Options" scenario from the Commonwealth's CECP for DG and the "Phased" scenario for EH. See Section 5.1.4 - 5.1.7 for further discussion of forecasting for each of the DERs.

A summary of the Company's approach to how each DER is independently forecasted is as follows:

EE	**Post-2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year. The residential savings growth rate slows by 15% annually to account for saturation of claimable savings until 2035 and stays flat thereafter until 2050 whereas the commercial savings growth rate slows by 5% annually until 2050.**
PV	Near-term (2023-2027) predictions leverage the information on the projects in the Company's interconnection queue and the insights from PV subject matter experts at the Company, and also assumes National Grid fills its share (45%) of the Commonwealth's existing solar standards of 3.2 GW by mid 2020s. In the longer-term, continuous growth is projected to achieve the Company's share (45%) of the Commonwealth policy target under the "All Options scenario" as stated in its 2050 decarbonization roadmap.
ESS	Throughout the forecast horizon, leverages information on the projects in the Company's interconnection queue, to meet the Company's share of the statewide energy storage policy goals. In Massachusetts, the state policy is 1,000 MWh by 2025. Beyond 2025, the Company leverages assumptions in the CECP and "Energy Pathways to Deep Decarbonization 2050" studies. The base scenario will be between "All Options" and "100% renewable" scenarios.
EV	**Light Duty:** The base case is developed around California's Advanced Clean Car II (ACC-II) rules, which have been adopted by Massachusetts. **Medium Duty/Heavy Duty:** The base case for the adoptions of medium-duty EV (MHDEV), heavy- duty EV (HDEV) and E-buses is based on the California's Advanced Clean Trucks (ACT) rules through 2035, which have been adopted by the Commonwealth.
EHP	The Company's three-year plan approved by the Department guides EHP adoption projections through 2024. Post 2024, the Company assumes the Company's pro rata share of CECP Phased pathway's target in 2050 will be met. Thus, about 1.34 million units will be installed by 2050 and about 80% of those will be installed as full applications. Penetration rates are expected to be about 86% of residential homes and 58% of commercial space heating capacity by 2050.

5. **System Peak Forecast:** The econometric forecast (Step 3) and DER forecasts (Step 4) are combined into the aggregate demand to create a final system peak forecast of total net load. The results of this forecast are used as input into various system planning studies, including distribution planning (and transmission planning), in conjunction with the weather design criteria defined in Step 1.
6. **Spatial allocation:** In addition to the demand forecast at the system level, the Company also develops forecasts at a more granular level. The econometric and DER forecasts are independently allocated to different planning areas based on local census and parcel-level characteristics. Each DER is allocated independently at this granular level since DER penetration is not assumed to be uniform across the Company's service territory. For example, large PV installations may be more likely to be developed in areas where land is more plentiful and less expensive and closer to interconnection points. For presentation and reporting purposes in the ESMP, the granular forecasts are aggregated to the sub-region

level and discussed further below (Sections 5.2 to 5.7).

7. **Validation:** The Company benchmarks its forecast against the CECP. The underlying assumptions for the DERs in the Company forecast align with the targets in the CECP "Phased" and "All Options" Pathways (see Sections 5.1.4 - 5.1.7 for additional detail). The CECP Pathways Analysis[3] expects approximately 10% growth in peak demand from 2020 – 2030 which matches the expected growth in the Company's forecast over the same period, validating the Company's work aligning with the CECP.

Comparison with Eversource and Unitil:

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 methodologies employed by each individual EDC are aligned for the baseload econometric forecast, design weather conditions, and DERs. The table below provides a high-level comparison of the methodologies used by the EDCs. More detail specific to each EDC is in section 5 of the respective Plans.

Category	National Grid	Eversource	Unitil
Weather Data	Utilize more than a decade of historical weather data to develop the design weather – the 90th percentile – and use it as the primary planning case. The specific weather stations used are region dependent.		
Forecasting Model – Baseload	Econometric forecast model for the baseload.	Econometric forecast model for the baseload.	Projects recent historic growth forward for baseload.
DER Forecasts	Each DER is independently forecasted considering their current market trend, policies, programs, and State decarbonization pathways.		
Regional Forecasts	Produce the forecasts at the jurisdiction level and allocate to more granular geospatial areas based on regional characteristics.		
Energy Efficiency	Near term: Company three-year plan approved by the Department. Long-term: continued growth reflecting market saturation.	Company three-year plan approved by the Department continues to 2033.	Near term: Company three-year plan approved by the Department. Long-term: continued growth at similar rates.

[3] CECP, June 2022, page 72 Pathways Analysis: Electrification and Electric System Needs

Demand Response	Continuation of Company's DR programs with growth.	Not considered.	Not considered.
EV Adoption Forecasts	LDEV adoptions based on the Commonwelath's adoption of California's Advanced Clean Car Act II Regulation. MDEV and HDEV and E-buses based on Commonwealth's adoption of California's Advanced Clean Truck Act.	Following a trajectory that meets the 2050 MA CECP.	Near-term: Follow NE-ISO assumptions. Long-term: Align with Commonwealth goal under "All Options" Scenario.
Heat Pump Adoption	Near-term: three-year plan approved by the Department. Long-term: following a trajectory that meets the CECP "Phased" electrification scenario.	Following a trajectory that meets the "All Options" electrification scenario.	Near-term: three-year plan approved by the Department. Long-term: following a trajectory that meets the "All Options" electrification scenario.
Storage	Near-term: based on interconnection queue and meeting State policy target of 1,000 MW by 2025, with continued growth after.	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "High Electrification" scenario.	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "All Options" scenario.
Solar adoption	Near-term: based on interconnection queue. Long-term: Following a trajectory that meets the "All Options" scenario.		

Sections 5.1.1 - 5.1.7 will provide details on components of peak forecast across the entire jurisdiction (i.e., the Company's Massachusetts service territory), before diving into this same information broken down by six planning sub-regions in Sections 5.2 - 5.7.

5.1.1 Aggregate Demand – Summer and Winter

Aggregate demand refers to the net demand on the system (i.e., the sum of the baseload and DERs) that the infrastructure must be sized to meet. Historically, the annual demand peak has occurred in the summer season, typically during a very hot summer weekday afternoon. In recent years, the peak hour has gradually shifted to early evening as increasing penetration of DERs has begun offsetting the load earlier in the afternoon and becomes less available or unavailable later in the day towards sunset.

Historical aggregate peak demand is illustrated in Exhibit 5.2. Aggregate peak demand has remained relatively flat for over the last 15 years, since growth in baseload demand has been offset by increases in DERs. However, over the next 10 years, aggregate demand is projected to increase at a Compound Annual Growth Rate (CAGR) of 1.1% through 2029 and 2.1%[4] through 2034 due in large part to increasing electrification. Furthermore, the winter peak is increasing at a faster rate than the summer peak due to growth of EHPs. The system remains summer peaking through the near-term forecast period (2025 – 2034) discussed in this section. However, the system is projected to switch to winter peaking during the long-term demand forecast period (2035 – 2050) described in Section 8.

Exhibit 5.2: Historical and Forecasted Aggregate Peak Demand for Summer and Winter

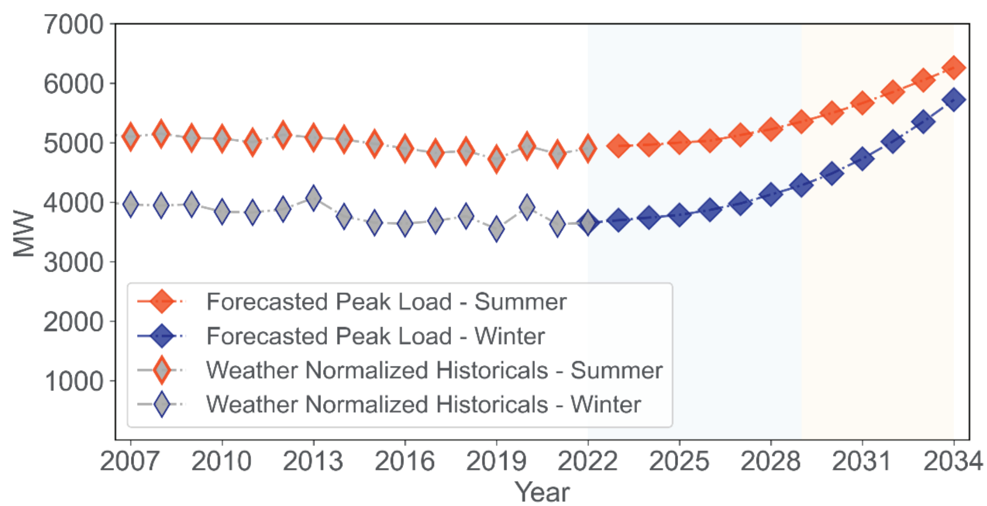


Exhibit 5.3: 90/10 Summer Peak Forecasts by Region

Forecast Year	Central	Merrimack Valley	North Shore	South Shore	Southeast	Western
2023	883.9	1018.6	724.2	887.5	932.9	397.4
2024	902.6	1025.7	733.1	890.8	939.5	402.1
2025	909.6	1037.3	743.8	899.6	949.3	406.1
2026	919.2	1044.9	752.1	905.6	956.5	413.3
2027	938.3	1061.7	766.2	918.5	967.2	425.1
2028	971.9	1077.7	779.0	933.2	985.0	436.9
2029	984.5	1098.1	795.8	950.7	1003.2	451.9
2030	1008.3	1122.7	813.7	971.0	1026.2	468.0

[4] The starting year is 2022 for all CAGR calculations in Section 5.

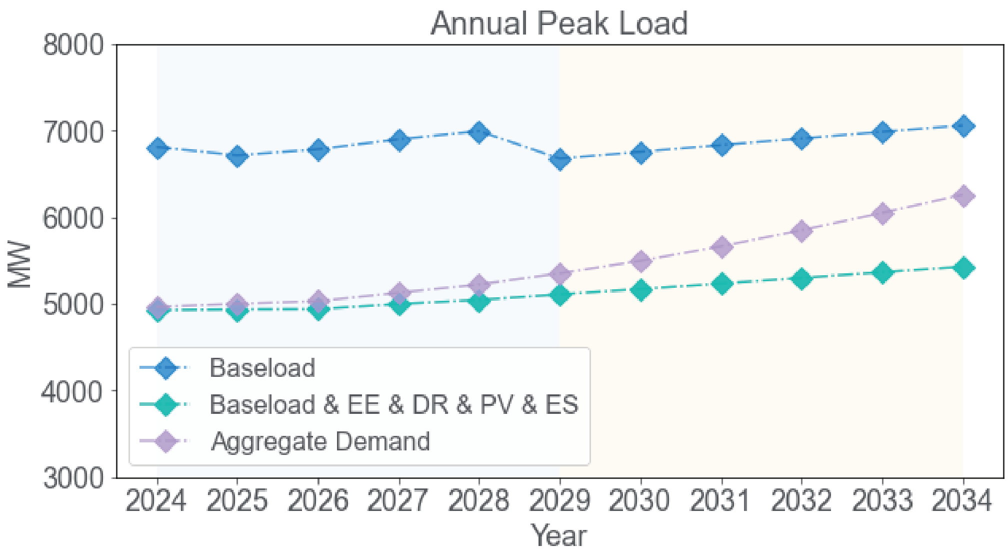
2031	1041.1	1150.9	834.6	998.0	1053.8	484.8
2032	1075.3	1177.3	856.7	1032.2	1084.8	503.6
2033	1110.1	1208.4	881.0	1068.7	1120.0	527.1
2034	1155.4	1244.4	908.1	1105.9	1156.4	551.4

Exhibit 5.4: Territory Wide Peak Demand Forecast Component Overview in MW

Forecast Year	Baseload	EE Impact	Solar Impact	EV Load	Heating	BESS	DR	Net-Forecast
2023	6709	-1338	-207	20	4	-161	-83	4944
2024	6812	-1375	-226	31	8	-196	-89	4965
2025	6717	-1407	-32	55	10	-247	-94	5001
2026	6785	-1435	-34	79	14	-280	-98	5032
2027	6900	-1458	-36	111	19	-306	-102	5129
2028	6996	-1477	-39	154	25	-327	-107	5225
2029	6678	-1494	0	215	28	9	-84	5352
2030	6757	-1508	0	292	35	10	-88	5497
2031	6834	-1521	0	390	42	10	-90	5665
2032	6910	-1531	0	503	51	10	-93	5851
2033	6987	-1540	0	627	62	10	-95	6052
2034	7061	-1547	0	760	74	10	-98	6261

The projected demand growth is primarily due to projected increased beneficial electrification from EVs in accordance with the State's climate goals, as well as cumulative EE savings that are beginning to grow at a slower rate as incremental EE savings become harder to come by due to long-term program success. Moreover, while PV adoption continues to grow, the peak hour shifts later in the day when PV has less of an impact on peak demand. Exhibit 5.2 illustrates how the saturation of EE and the shift to a later peak hour when PV has limited impact mean that DERs (excluding EV and EH) are not projected to offset the underlying growth in electricity demand in the future. To see this, compare the roughly parallel tracks of the top and bottom lines, (where the kink in the baseload demand is from PV and EV charging load pushing the peak hour later in the day), which demonstrates that EE, DR, PV, and ESS are not offsetting increases in baseload. In addition, comparing the middle line in the exhibit to the bottom line shows the substantial uptick in demand driven by EVs.

Exhibit 5.5: Annual Peak Load by Components



The waterfall charts in Exhibits 5.6 to 5.8 show the breakdown of aggregate demand in years 2022, 2029, and 2034, respectively. The red bars represent DERs that offset aggregate demand (EE, DR, PV, and ESS), while the blue bars represent net contributors to peak load (EVs and EHPs). Out of the DERs, EE has by far the biggest impact offsetting aggregate demand through this time horizon. The impact of EVs grows rapidly during this period before becoming the second largest factor offsetting baseload demand by 2029. Both EVs and EHPs increasingly contribute to peak load over the years.

Exhibit 5.6: Aggregate Peak Load by Components in 2022

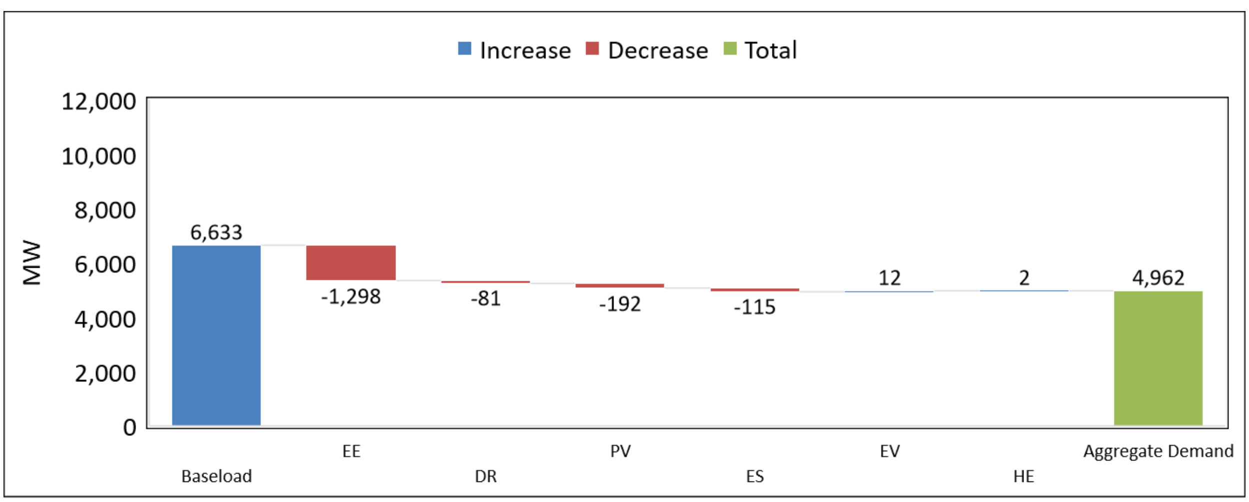


Exhibit 5.7: Aggregate Peak Load by Components in 2029

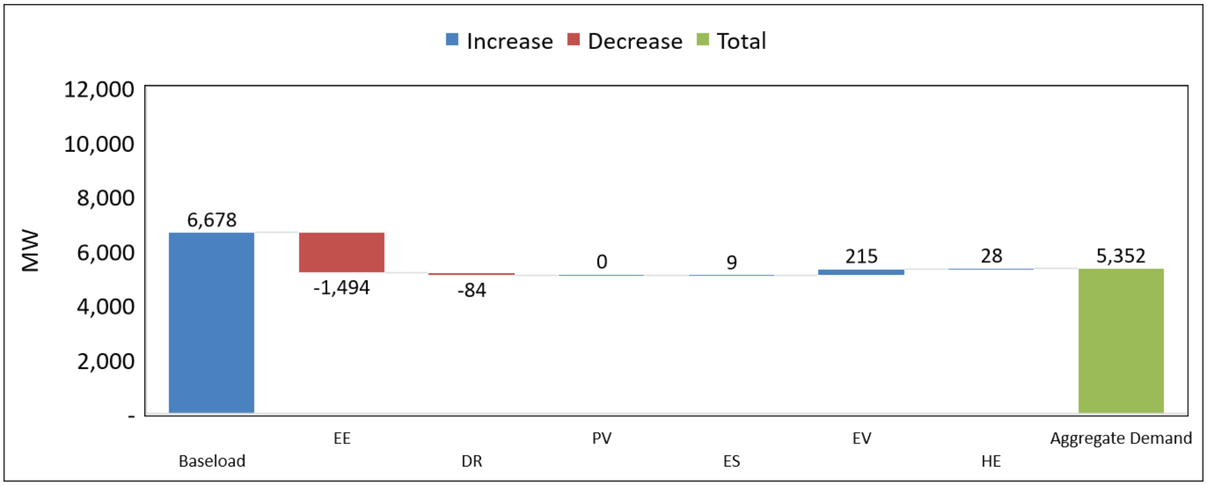
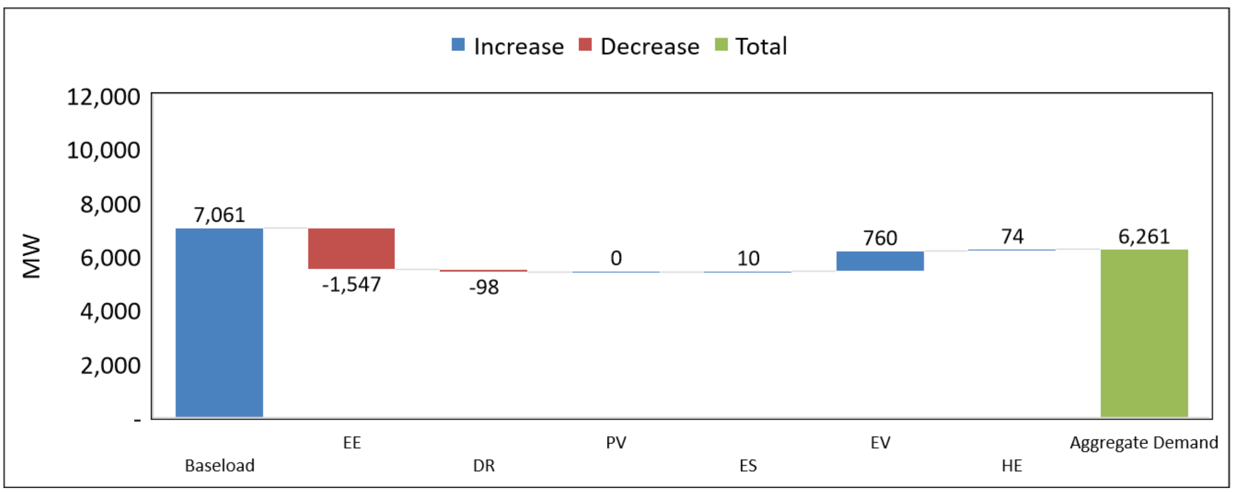


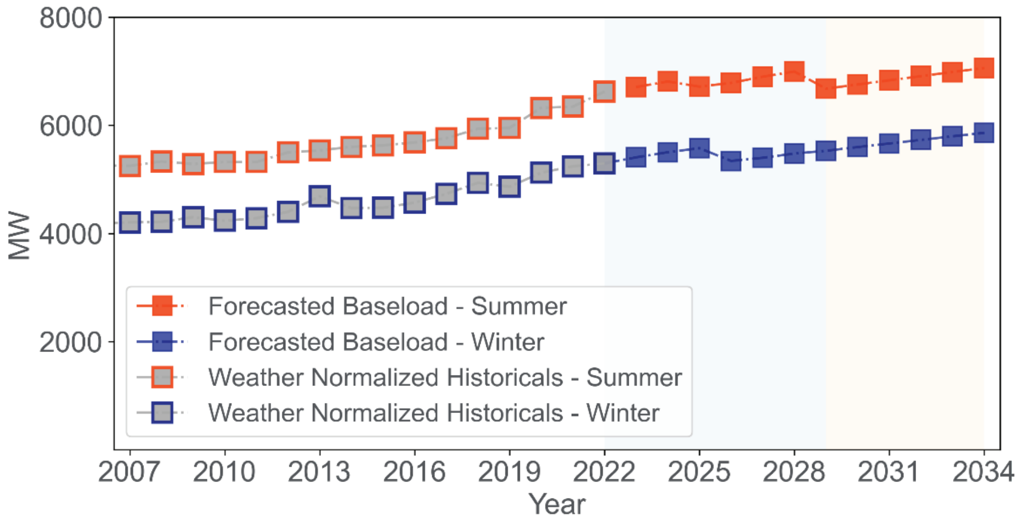
Exhibit 5.8: Aggregate Peak Load by Components in 2034



5.1.2 Weather Normalized Econometric Forecast

Exhibit 5.9 presents the historical and forecasted baseload at the hour of peak demand. The peak hour is expected to shift from the late afternoon (17:00-18:00) to the evening due to PVs offsetting load during the day. This shifting of the peak hour shows up as the two step-downs of the forecasted summer baseload in 2025 and 2029. The peak baseload is forecasted to grow at a CAGR of 1.1% over the forecast horizon and is primarily driven by the economic outlook. Note that the baseload at the new evening peak hour will continue to be lower than forecasted baseload at the current peak hour in the afternoon, but because afternoon demand is partially offset by PV, aggregate demand will be highest in the evening.

Exhibit 5.9: Historical and Forecasted Baseload



5.1.3 Large Load (Step/Spot Load)

The demand forecast shows long-term trends in baseline demand growth from underlying economic activity and DER dynamics. Some of those demand drivers are service-territory-wide (e.g., the energy savings from widespread residential EE measures) and others are specific large loads located in one particular community (e.g., a new factory or data center). The Company does not forecast specific large loads. Rather, any new infrastructure needed to serve large loads is captured through the Company's interconnection and distribution planning processes.

5.1.4 Energy Efficiency

The Company has operated EE programs in Massachusetts for many years, contributing to Massachusetts being recognized as a national leader in implementing high-quality EE programs.[5] The Company will continue to operate its nation leading EE programs for the foreseeable future with support from state policies and funding. In the short-term (i.e., through year 2024), EE targets in the forecast are based on the Company's three-year EE plan approved by the Department. Beyond the year 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year reflecting market saturation and uncertainties in policies and funding as shown in Exhibit 5.10.

The Company's demand forecast does not explicitly model building code changes. However, the historical evolution of building codes to become more energy efficient is captured in the underlying econometric baseload forecast (see Section 8.2.3 for more discussion).

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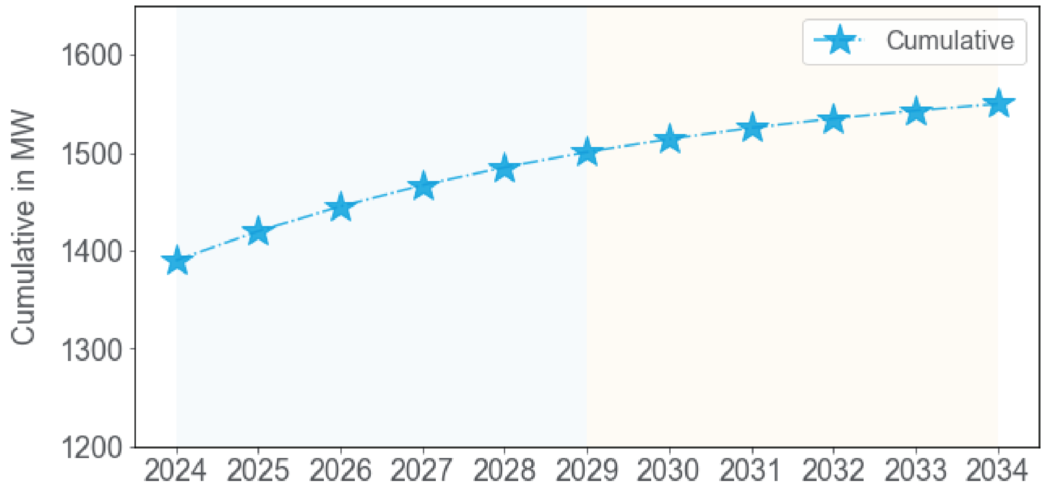
[5] https://www.aceee.org/state-policy/scorecard

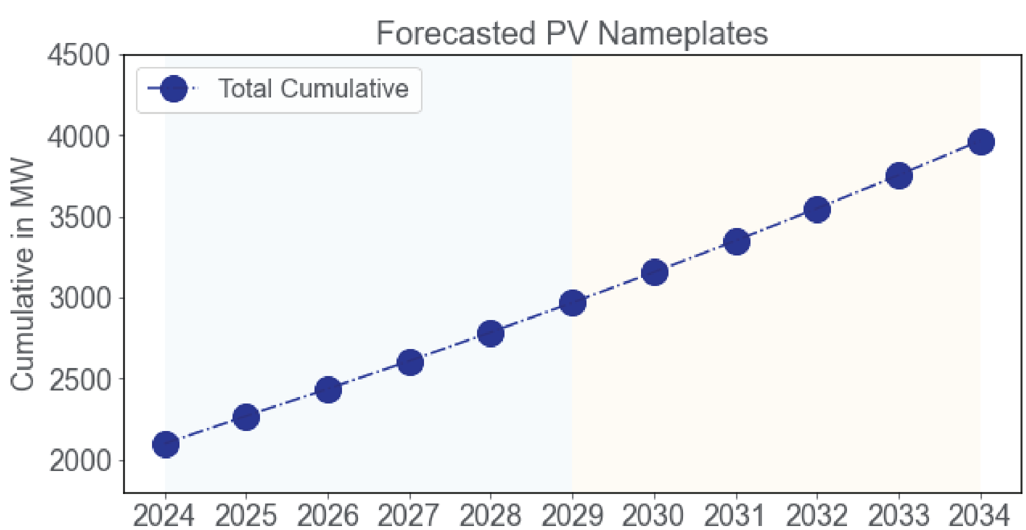
Exhibit 5.10: Forecasted and Cumulative EE Savings



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

There has been a rapid increase in the adoption of **Solar PV** throughout the Commonwealth. The near-term (2023 – 2027) predictions leveraged the information on the PV projects from the Company's interconnection queue and insights from the Company's PV subject matter experts, and assumes the Company fills its share of the Commonwealth's existing solar target of 3.2 GW by the mid 2020s.[6] In the longer term, continuous growth in PV is projected to achieve the Company's share of the policy target under the "All Options" scenario, as stated in the Commonwealth's 2050 decarbonization roadmap[7]. See Exhibit 5.11 for additional details on the forecasted PV Nameplate Capacity**.**

Exhibit 5.11: Forecasted PV Nameplate Capacities



[6] CECP, page 68, June 2022.
[7] https://www.mass.gov/info-details/ma-decarbonization-roadmapDecember 2020.

Energy Storage (ESS) deployment is still at a relatively early stage across the Commonwealth. Growth has been rapid for only a few years. The forecast leverages information from the Company's interconnection queue and assumes continuous growth in ESS connection to meet the Company's share of the statewide policy target of 1,000 MW by 2025.[8]

The Company currently runs a Mass Save summer **Demand Response** (DR) program to reduce electricity demand during hours with high expected demand and/or reliability problems. During a DR event, customers can participate by either cutting their consumption (e.g., turning down/off their air conditioners, not charging their EV) or by supplying energy (e.g., by turning on a generator or discharging a battery (ESS) to supply their demand). The Company offers various ways (e.g., thermostat controls, batteries, and programs to encourage C&I customers to fall back to alternative generators) for customers to participate. As of 2022, it is estimated that the Company's DR program helped reduce the peak by about 1.3%. Through the year 2025, projected growth of the program is informed by the Program Administrator. Beyond that and through the forecast horizon, a similar incremental growth is assumed, leading to growth of about 60% by 2034 compared to 2022.

5.1.6 Electric Vehicles

The EV forecast includes both plug-in hybrid electric vehicles (PHEVs) and battery-only electric vehicles (BEVs) since they both impact electric demand. Below are the modeling assumptions for forecasting light-duty and medium- and heavy-duty vehicles:

Light-Duty EV (LDEV) adoption is modeled off California's Advanced Clean Car II (ACC-II) rules, which have been adopted by Massachusetts[9] and is consistent with the "All Options" scenario and the 2025/2030 CECP. This regulation requires auto manufacturers to ensure that every new light-duty car sold in the Commonwealth is a zero-emission vehicle (ZEV) by 2035. This is in line with the requirement for all new passenger cars and light-duty trucks sold in Massachusetts to be zero-emission starting in 2035, that was signed into law in the 2022 climate bill *An Act Driving Clean Energy and Offshore Wind*.[10]

Medium-Duty EV (MHDEV), Heavy-Duty EV (HDEV), and E-buses are similarly modeled off the California's Advanced Clean Trucks (ACT) rules through 2035, which have been adopted by Massachusetts[11] and are consistent with the "All Options Scenario" and 2025/2030 CECP. Exhibit 5.12 shows annual incremental and cumulative EV counts through the forecast period.

The Company recognizes that bidirectional charging is a developing technology and has the potential to affect future grid loading. That said, the market is nascent, and the Company does not expect it to have a material impact on demand by 2035. For more on directional charging and vehicle-to-grid (V2G) after 2035, please refer to Section 9. The Company will continue to monitor the bidirectional charging developments to best reflect them in its demand forecast and system planning.

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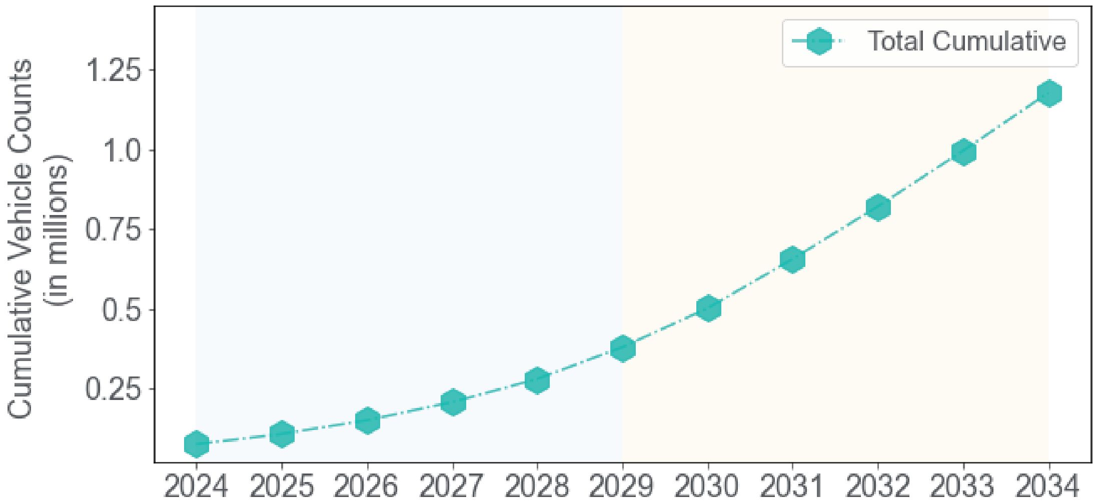
[8] https://www.mass.gov/info-details/esi-goals-storage-target, retrieved November 2022
[9] https://www.mass.gov/doc/310-cmr-740-low-emission-vehicle-regulation-amendments/download
[10] https://malegislature.gov/Laws/SessionLaws/Acts/2022/Section179
[11] https://www.mass.gov/doc/310-cmr-740-low-emission-vehicle-regulation-amendments/download

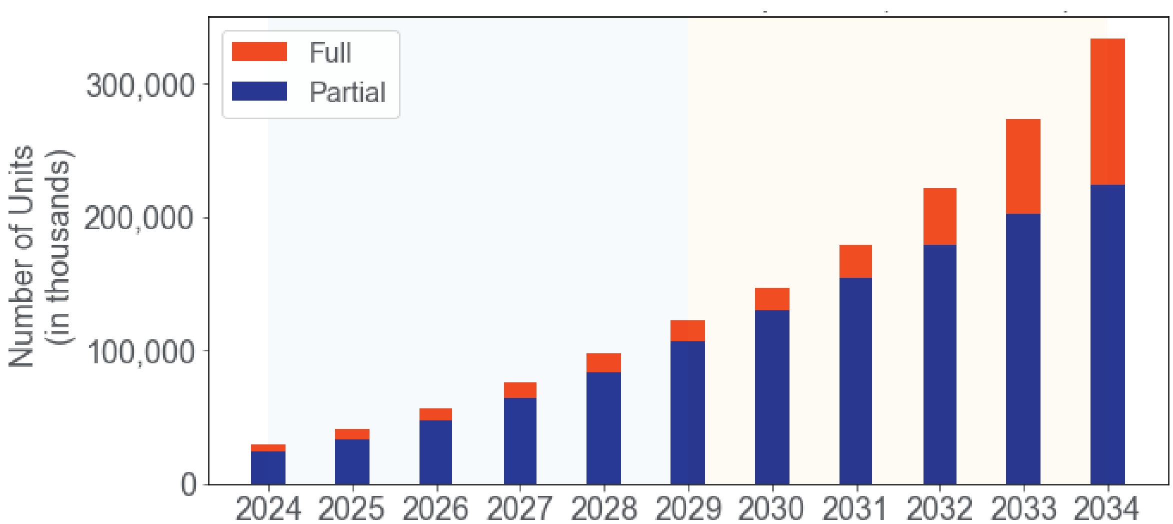
Exhibit 5.12: Forecasted Number of EVs in Operation



5.1.7 Heat Electrification

The Company's three-year Energy Efficiency plan approved by the Department starting in year 2022 guides Electric Heat Pump (EHP) adoption projections through the year 2024. Post year 2024, the forecast follows a trajectory that meets the Commonwealth's CECP "Phased" electrification scenario target by 2050, roughly aligning with interim state goals for 2030 and beyond. See Exhibit 5.13 for a graphical representation of EHP projections. Notably, all regions will remain summer peaking before 2034, hence the load impact on summer peaks from heat electrification is not meaningful compared to EV and other DERs.

Exhibit 5.13: Forecasted Electric Heat Pump Units (Cumulative)



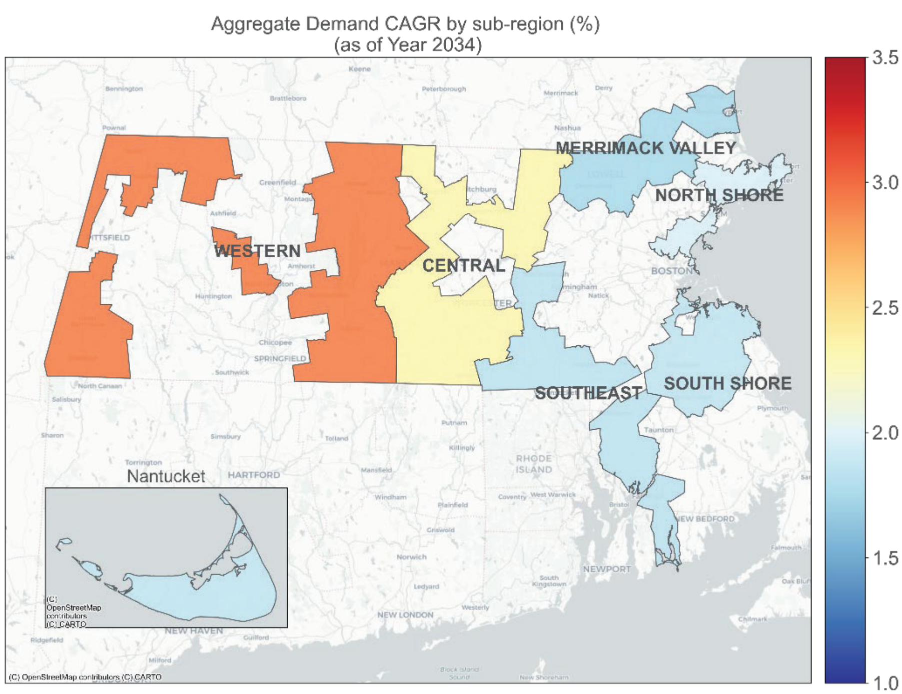
Planning Sub-Regions

Starting in Section 5.2 below, the details of the Company's demand forecast are presented for the same six sub-regions described in Section 4. Exhibit 5.14 illustrates the six sub-regions and shows their Aggregate Demand CAGR through 2034. Some key takeaways from the forecasts by sub-region are described below:

- The **Western sub-region** has the most significant growth (about 2.9%) due to faster baseload growth and considerable EV adoption projected.
- The **Central sub-region** has about 2.3% CAGR with relatively high EV adoption and moderate baseload increase.
- The **North Shore sub-region** is projected to experience 2% CAGR aggregate demand growth with moderate EV adoption and baseload growth.
- The **South Shore sub-region** has about 1.9% CAGR because of high growth in EV penetration, high EE savings, and moderate PV increases.
- The **Southeast** and **Merrimack Valley sub-regions** have the lowest overall CAGR (about 1.8%) with lower EV penetration and lower baseload growth compared to other sub-regions.

For each sub-region, we will describe the components of aggregate demand from the previous Sections.

Exhibit 5.14: Aggregate Demand CAGR by Sub-Region



5.2 Central Sub-Region

5.2.1 Aggregate Demand – Summer and Winter

The Central sub-region currently has the second largest electricity demand and is expected to witness steady load growth with significant DER adoptions, especially in PV.

The Central sub-region remains summer peaking through the forecast horizon. Cumulative peak load change is illustrated in Exhibits 5.15 and 5.16 below. For the 5-year horizon, peak baseload demand is expected to increase by 98 MW, which is the main driver for the peak increase. Transportation electrification has the second largest impact, adding an additional 39 MW of demand at peak. Both EE and PV are expected to result in moderate reductions to final net peak load, each reducing peak net load by 17 MW. Collectively, all of the load component variations lead to 107 MW growth in net peak demand for the Central sub-region.

For the 10-year forecast ending in 2034, baseload remains the largest driver with a 156 MW increase. EV sales are expected to rapidly ramp up, resulting in an additional 150 MW of demand on the distribution system at peak. Similar trends for EE and PV are forecasted as in the previous horizon with overall limited peak shaving impacts due to the relatively late peak hour (ending at 18:00) and thus reducing the role of PV. The final net increase to peak hour demand for the Central sub-region is projected to be about 278 MW.

Exhibit 5.15: Load Change from 2022-2029 – Central Sub-Region

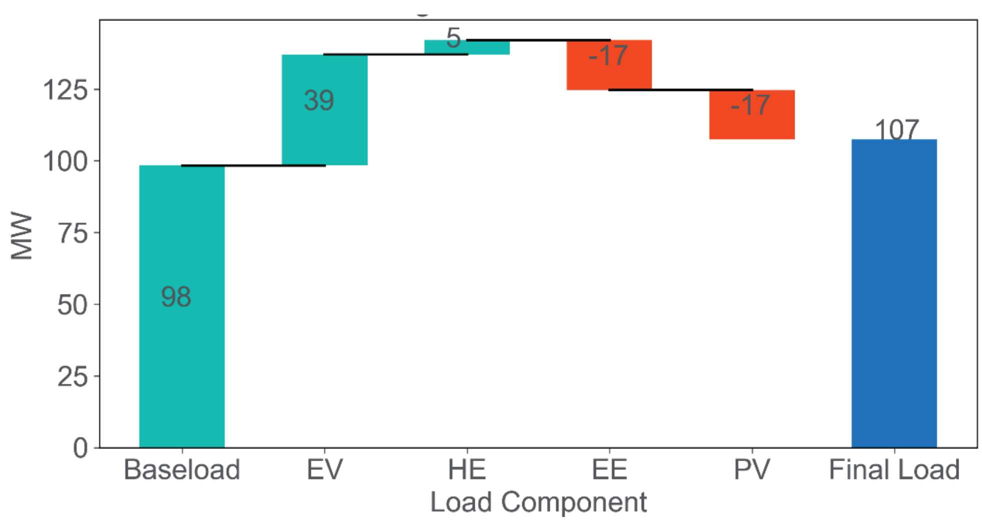
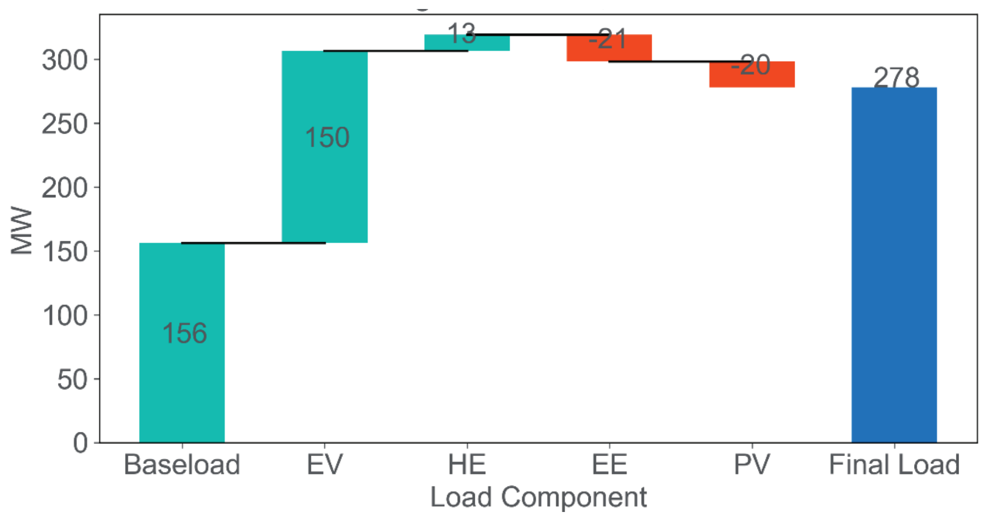


Exhibit 5.16: Load Change from 2022-2034 – Central Sub-Region



5.2.2 Weather Normalized Econometric Forecast

The baseload growth in each sub-region is derived from the Company's outlook on the ISO load zone[12] that the sub-region falls into and the sub-region's recent growth within the zone. The zonal level outlook captures the macroeconomic impacts, while within the load zone, each sub-region's recent growth reflects the variation among sub-regions in the same load zone. The Central sub-region mostly falls into the Western Central Massachusetts (WCMA) load zone. The forecast on WCMA is discussed in the Appendix. The CAGR expectations for the WCMA load zone are 1.2% by 2029 and 1.1% by 2034. The Company's CAGR projections for the Central sub-region are 1.8% annual growth by 2029 and 1.6% through 2034, which are relatively high compared to other sub-regions.

5.2.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.2.4 Energy Efficiency

There are substantial EE savings projected in the Central sub-region due to its high energy consumption. The EE saving trend is depicted in Exhibit 5.17 with a CAGR of 1.9% ending in 2029 and 1.4% for the Company's 10-year horizon ending in 2034, resulting in the sub-regional EE savings increasing from 350 MW to about 390 MW.

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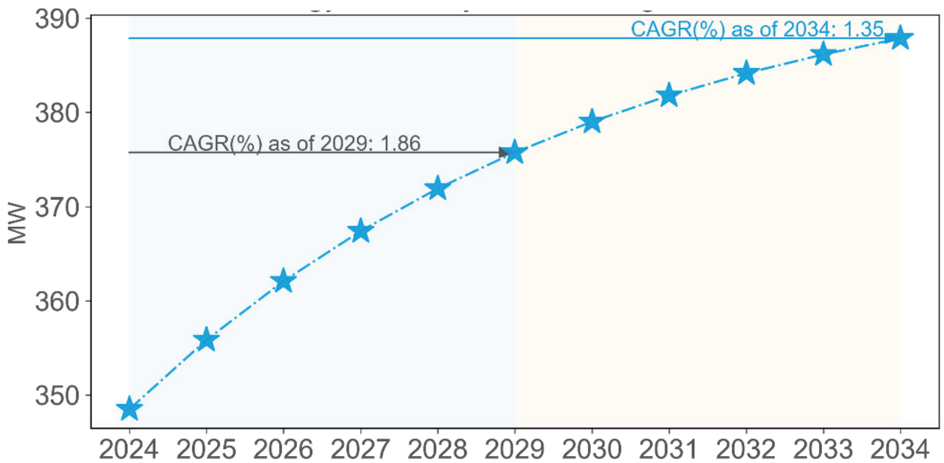
[12] https://www.iso-ne.com/about/key-stats/maps-and-diagrams#load-zones

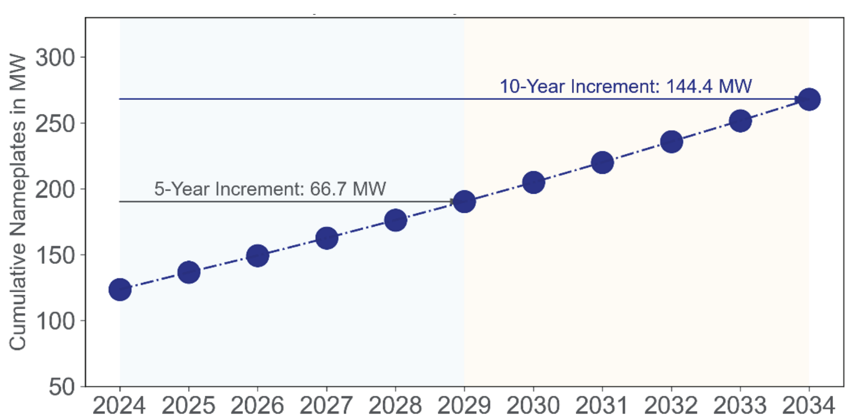
Exhibit 5.17: EE Peak Savings – Central Sub-Region



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

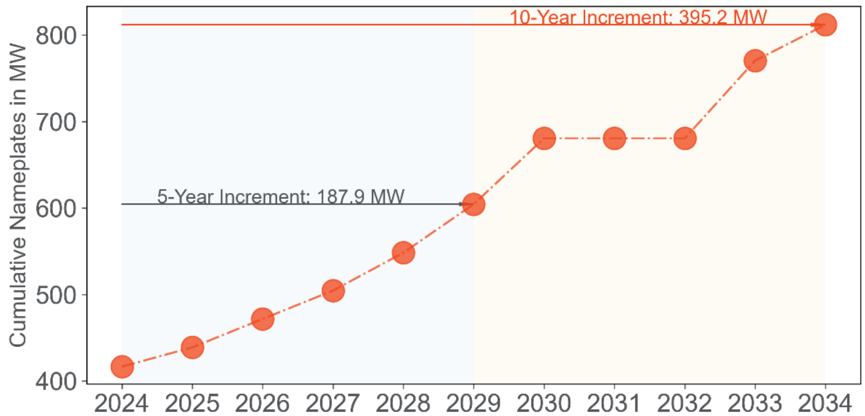
With the dense population in Worcester and its surrounding medium- to high-income neighborhoods, rooftop solar is projected to grow steadily within the Central sub-region. The 5-year incremental growth is forecasted to be 66.7 MW and the 10-year growth is 144.4 MW starting from the end of 2024 (Exhibit 5.18). For non-rooftop solar, this region has ample and affordable land parcels that meet Guideline Regarding Land Use, Siting, and Project Segmentation,[13] which results in a large growth margin for solar projects. Based on the current project queue information, 187.9 MW growth is expected through 2029 and 395.2 MW growth is expected by the end of 2034 (Exhibit 5.19). Combining rooftop solar with other solar, projections show total growth in solar reaching over 1000 MW. This causes the Central sub-region to become the sub-region with the largest cumulative PV capacity.

Exhibit 5.18: Rooftop Solar Adopting Trend – Central Sub-Region



[13] Guideline Regarding Land Use, Siting, and Project Segmentation revised September 22, 2021 (225 CMR 20.00) https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program#program-guidelines-

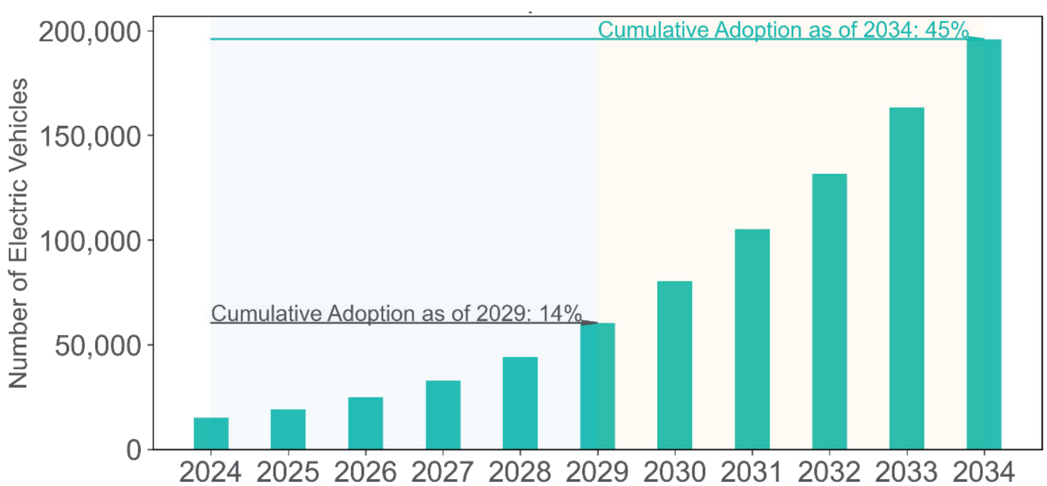
Exhibit 5.19: Non-Rooftop Solar Adopting Trend – Central Sub-Region



5.2.6 Electric Vehicles

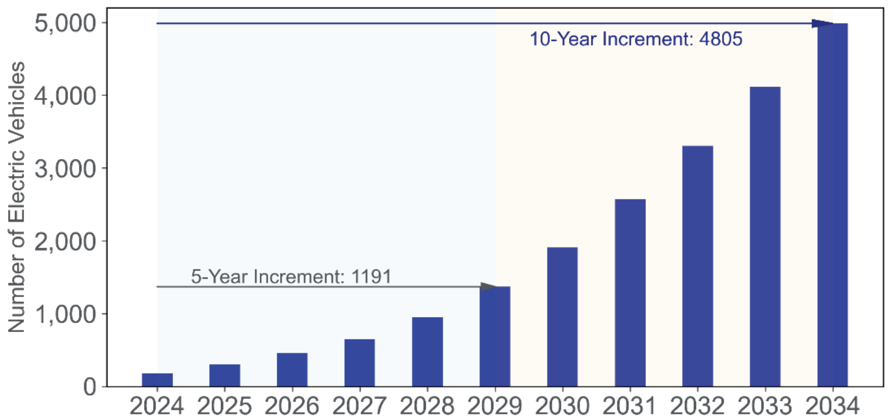
As one of the most populous regions within the Company's service territory, projections for EV adoption in the Central sub-region show about 50,000 additional LDEVs to be on the road by 2029 (compared to 2024). This is about 14% of all LDEVs on the road in the service territory by the end of 2029 (Exhibit 5.20). With an accelerating growth trend, LDEVs are projected to account for about 45% of all light duty vehicles in the Central sub-region by the end of the 10-year forecast horizon.

Exhibit 5.20: LDEV Adoption Trend – Central Sub-Region



The MHDEV forecast combines both medium and heavy-duty vehicles as well as buses, and the sub-regional forecast for the Central sub-region indicates about 1200 additional medium and heavy-duty vehicles will be electrified within the 5-year forecast horizon (Exhibit 5.21a). More rapid growth will take place afterwards with an additional 4800 MHDEVs in the Central sub-region by the end of 2034.

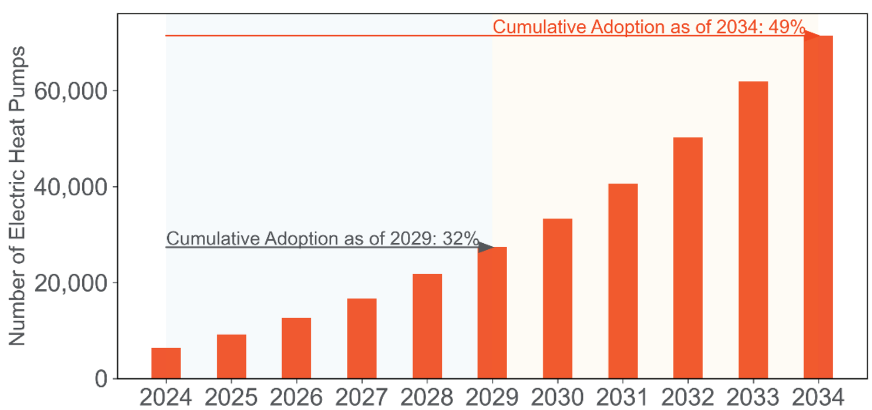
Exhibit 5.21a: MHDEV Trends – Central Sub-Region



5.2.7 Heat Electrification

There is currently a high penetration of delivered fuels (i.e., fuel oil and propane) for household heating in the Central sub-region. As a result, the Company projects relatively rapid EHP growth and a higher share of EHP adoption relative to other sub-regions. This is due to the economic and climate benefits heat electrification has for customers currently utilizing delivered fuels. Based on the Commonwealth's policy goals, EHP adoption is projected to reach 32% of all customers[14] by the end of 2029, and about 50% by the end of 2034 with about 70,000 units (including both full and partial) installed (Exhibit 5.21b). Because this sub-region remains summer peaking through the forecast horizon, EHPs have minimal impact on the peak forecast through 2034; however, this rapid EHP adoption puts the Central region on a trajectory to become winter peaking in the later 2030's (see Section 8).

Exhibit 5.21b: Electric Heat Pump Adoption Trend – Central Sub-Region



[14] This is the percentage EHPs divided by the number of electric customers forecasted at each year, including residential and commercial customers, excluding those who currently have electric heating (same for all regions).

5.3 Merrimack Valley sub-region

5.3.1 Aggregate Demand – Summer and Winter

The Merrimack Valley sub-region is forecasted to witness moderate load growth with overall moderate DER adoptions across all DER categories, as shown in Exhibits 5.22 and 5.23. The 5-year aggregate growth is 90 MW, and the 10-year growth is 236 MW.

Exhibit 5.22: Load Change from 2022-2029 – Merrimack Valley Sub-Region

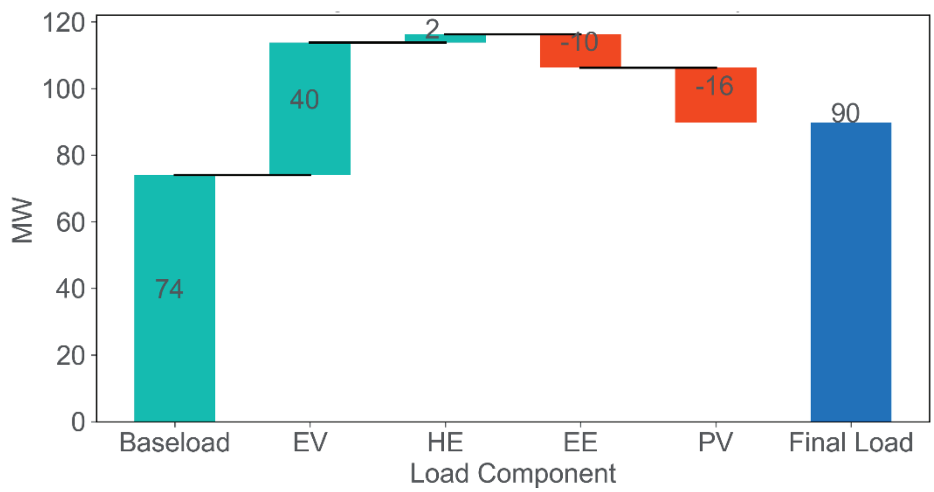
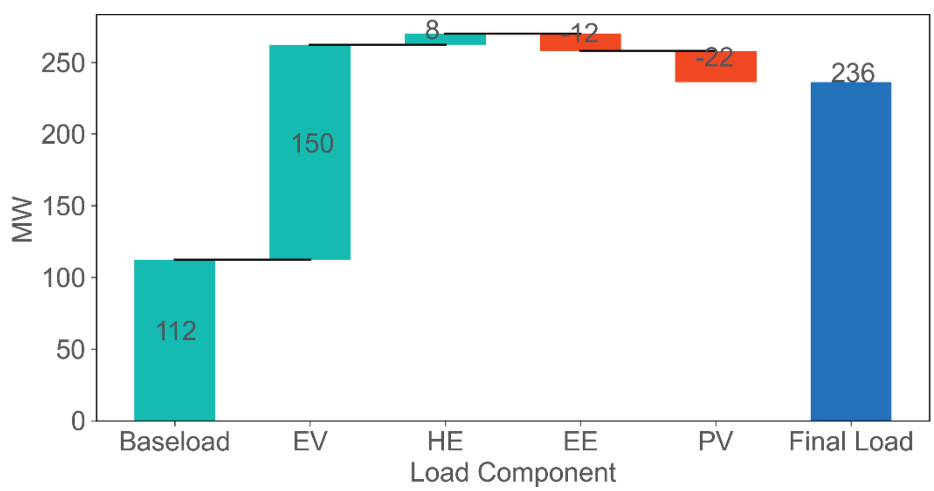


Exhibit 5.23: Load Change from 2022-2034 – Merrimack Valley Sub-Region



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5.3.2 Weather Normalized Econometric Forecast

The Merrimack Valley sub-region falls partially into the WCMA load zone and partially into the Northeastern Massachusetts (NEMA) ISO-NE load zone. The econometric forecasts for the WCMA and NEMA load zones are discussed in the Appendix. Overall, the CAGR expected for both the WCMA and NEMA load zones is 1.2% by 2029 and 1.1% by 2034. The CAGR expected for the

Merrimack sub-region is an average annual growth of 1.1% by 2029 and 1.0% through 2034, a moderate increase.

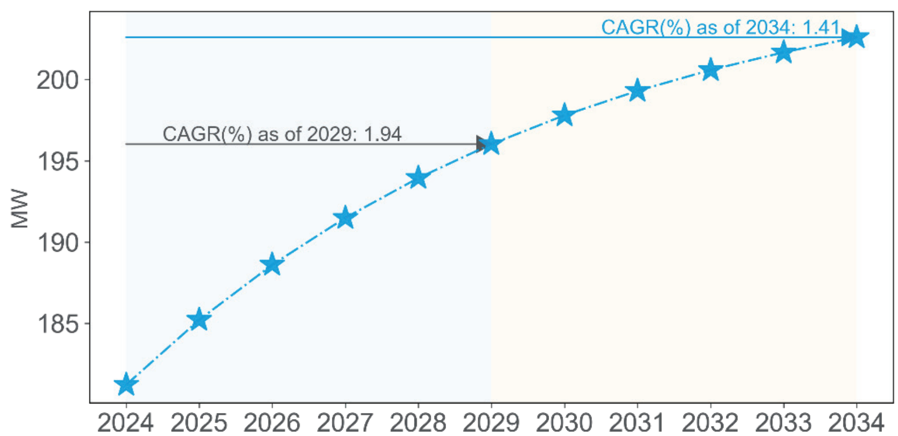
5.3.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.3.4 Energy Efficiency

The Merrimack Valley's EE savings forecast exhibits a steady growth pattern. The CAGR for the Merrimack Valley EE savings is 1.9% through 2029, and, for the Company's 10-year forecast until 2034, it stands at 1.4%, reaching a cumulative peak savings of 206 MW.

Exhibit 5.24: Energy Efficiency Peak Savings – Merrimack Valley Sub-Region



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

The Merrimack Valley sub-region is anticipated to experience a consistent increase in rooftop solar installations given the large number of residential customers. The forecast shows a 5-year increment of 74 MW and a 10-year increment of 163 MW (Exhibit 5.25). Non-rooftop PV (Exhibit 5.26) has continuous growth through 2029, surpassing 170 MW in cumulative installation, and then slows down between 2029 and 2034, resulting in moderate growth.

Exhibit 5.25: Rooftop Solar Adoption Trend – Merrimack Valley Sub-Region

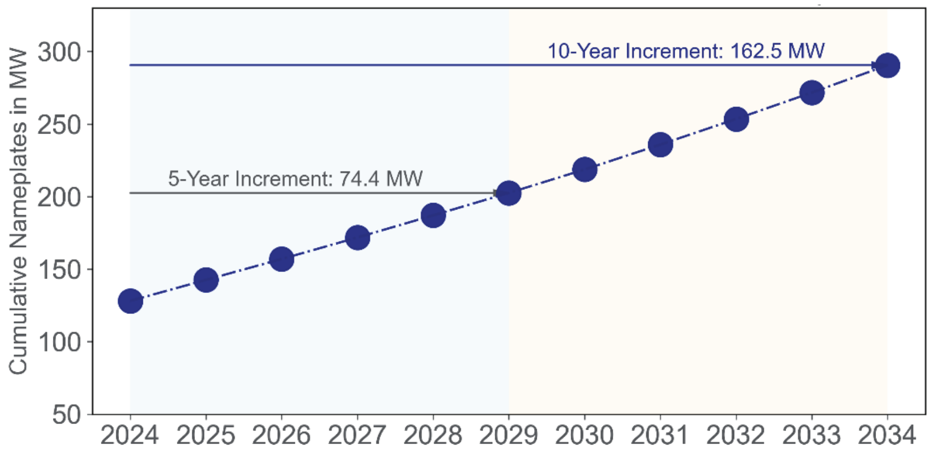
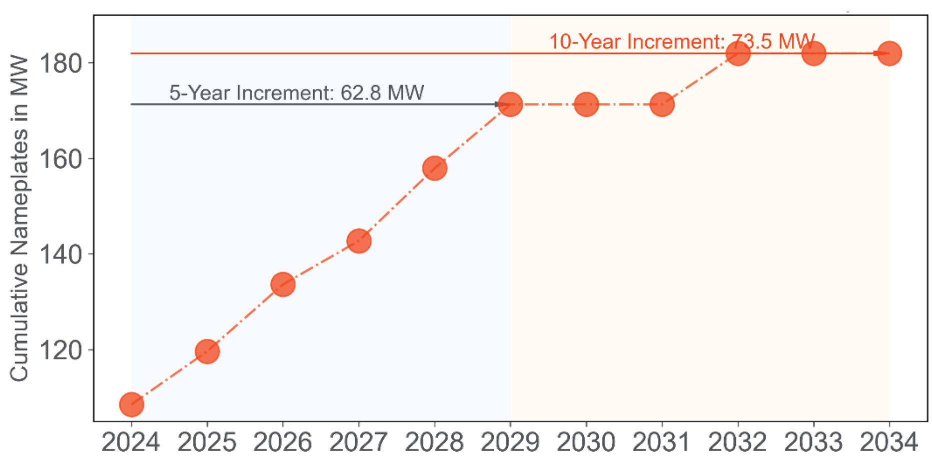


Exhibit 5.26: Non-Rooftop Solar Adoption Trend – Merrimack Valley Sub-Region



5.3.6 Electric Vehicles

Moderate LDEV penetration is expected to take place in the Merrimack Valley sub-region, with about 13% and 43% of light-duty vehicles on the road being electric by the end of 2029 and 2034, respectively, (Exhibit 5.27). The total number of LDEVs is forecasted to exceed 200,000 within the Merrimack Valley sub-region by the end of 2034. Approximately 1,000 medium and heavy-duty vehicles are expected to transition to electrification by the end of the Company's 5-year horizon (Exhibit 5.28). A more accelerated growth pattern will follow in alignment with Commonwealth policy, leading to an additional 2,500 MHDVs being electrified in the next 5 years through 2034.

Exhibit 5.27: LDEV Adoption Trend – Merrimack Valley Sub-Region

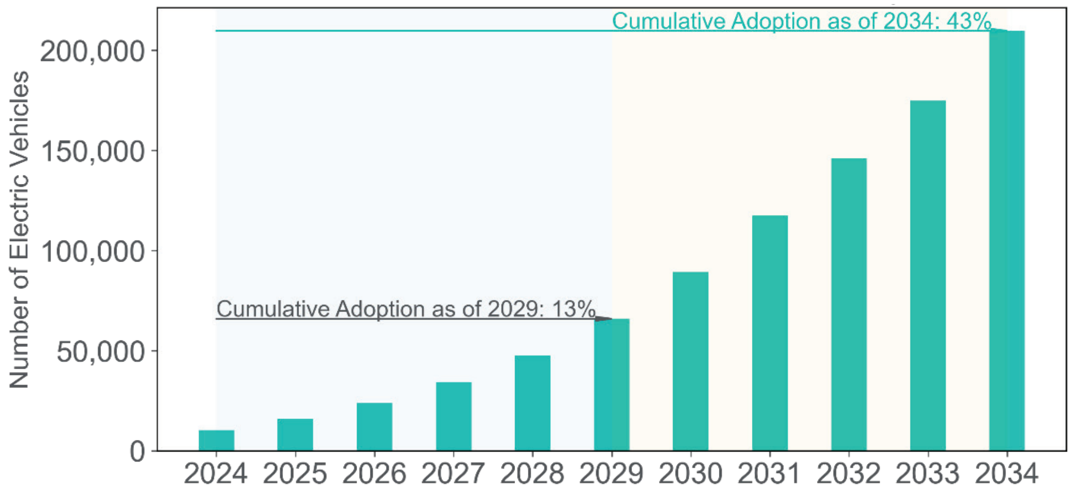
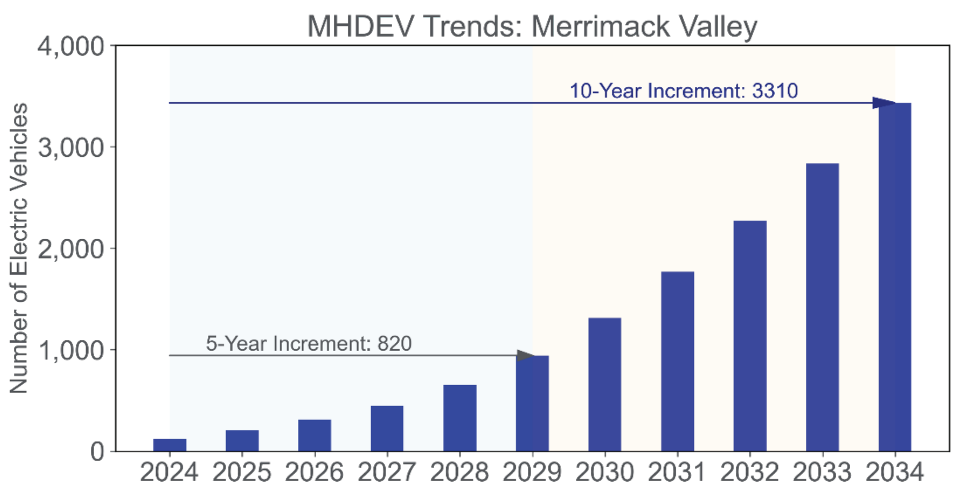


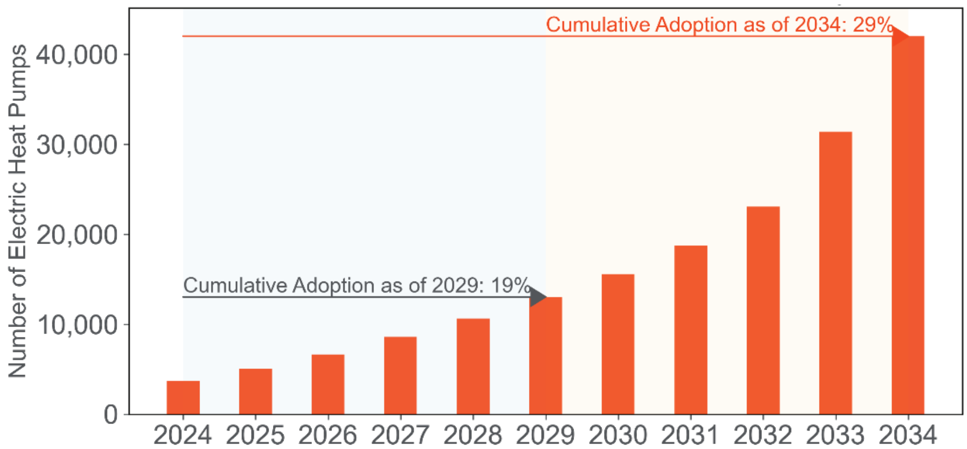
Exhibit 5.28: MHDEV Trends – Merrimack Valley Sub-Region



5.3.7 Heat Electrification

Given that the Merrimack Valley sub-region has both modest current EHP adoption as well as the lowest percentage of households utilizing delivered fuel for residential heating of any sub-region, it is expected to experience the mildest growth of heating electrification among all sub-regions, reaching about 30% EHP adoption across all electric customers by the end of 2034.

Exhibit 5.29: Electric Heat Pump Adoption Trend – Merrimack Valley Sub-Region



5.4 North Shore sub-region

5.4.1 Aggregate Demand – Summer and Winter

The North Shore sub-region is forecasted to witness moderate load growth due to a moderate EV adoption trend and low PV installation, reaching 78 MW of peak load growth through 2029, and 190 MW of aggregate peak load growth through 2034.

Exhibit 5.30: Load Change from 2022-2029 – North Shore Sub-Region

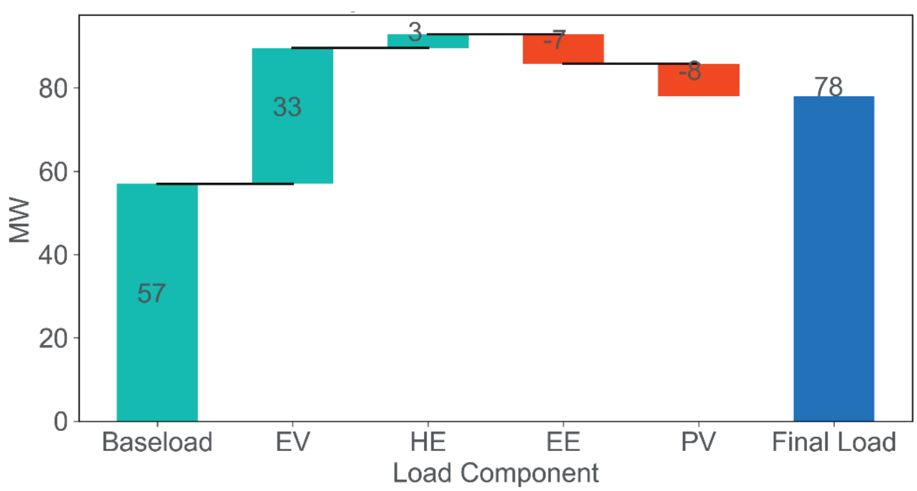
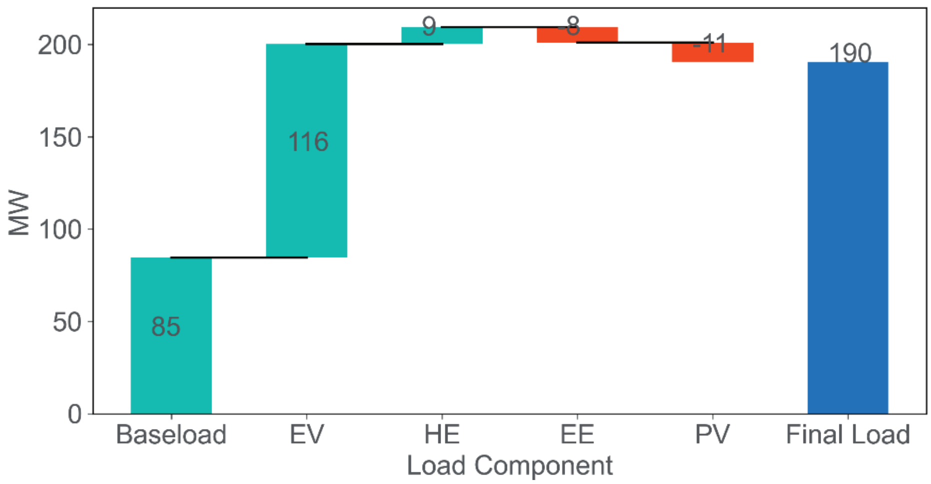


Exhibit 5.31: Load Change from 2022-2034 – North Shore Sub-Region



5.4.2 Weather Normalized Econometric Forecast

The North Shore sub-region falls entirely into the NEMA load zone. The forecast for NEMA is discussed in the Appendix. Overall, a 1.2% CAGR is expected for the NEMA load zone by 2029 and a 1.1% CAGR by 2034. The North Shore sub-region is expected to experience an average of 1.1% annual growth by 2029 and 1.0% through 2034, which is in the medium range in comparison with other sub-regions.

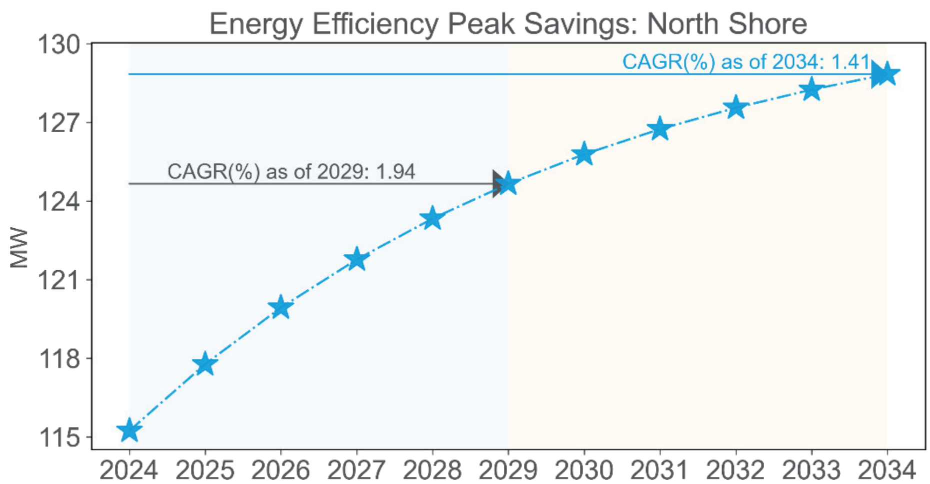
5.4.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.4.4 Energy Efficiency

Like the Merrimack Valley, the North Shore's EE saving forecast follows the growth pattern associated with the Company’s NEMA (ISO level) zone. The CAGR for the North Shore sub-region EE savings is 1.9% until 2029 and 1.4% through 2034 with a cumulative summer peak savings of 129 MW.

Exhibit 5.32: EE Peak Savings – North Shore Sub-Region



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

Due to the overall low availability of suitable land parcels and considerable number of residential customers, most of the PV projects that will be realized within the North Shore sub-region are rooftop solar. By the end of 2034, the North Shore sub-region is projected to have an additional 140 MW of rooftop solar and less than 10 MW of ground mounted solar.

Exhibit 5.33: Rooftop Solar Adoption Trend – North Shore Sub-Region

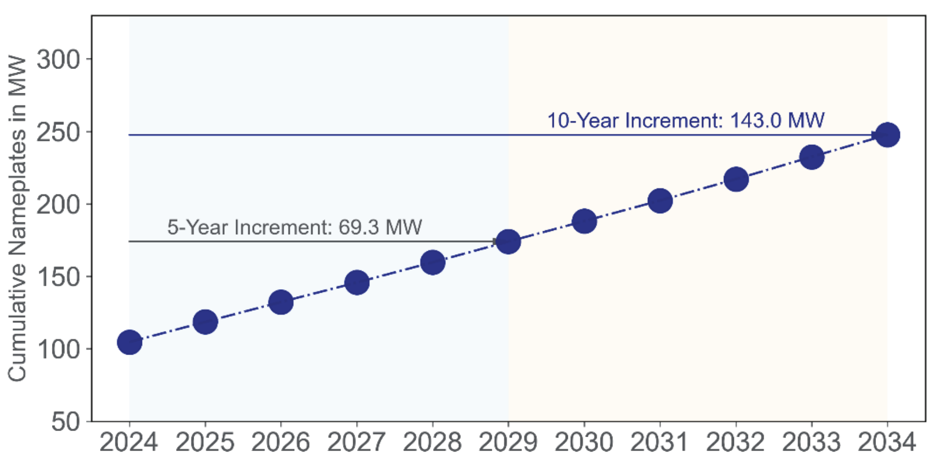
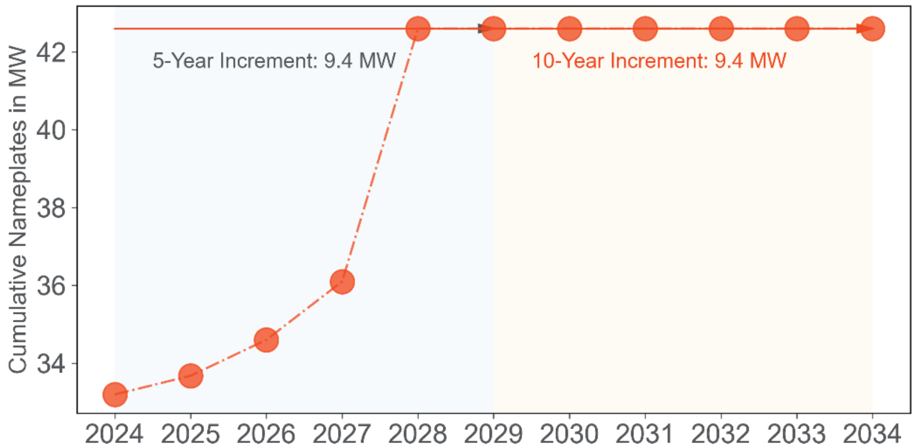


Exhibit 5.34: Non-Rooftop Solar Adoption Trend – North Shore Sub-Region



5.4.6 Electric Vehicles

EV adoption is expected to grow continuously in the North Shore sub-region, with the share of LDEVs rising to 15% before the end of 2029 and 43% by 2034. As for MHDEVs, moderate adoption is forecasted with the final number of MHDEVs for 2034 surpassing 2100.

Exhibit 5.35: LDEV Adoption Trend – North Shore Sub-Region

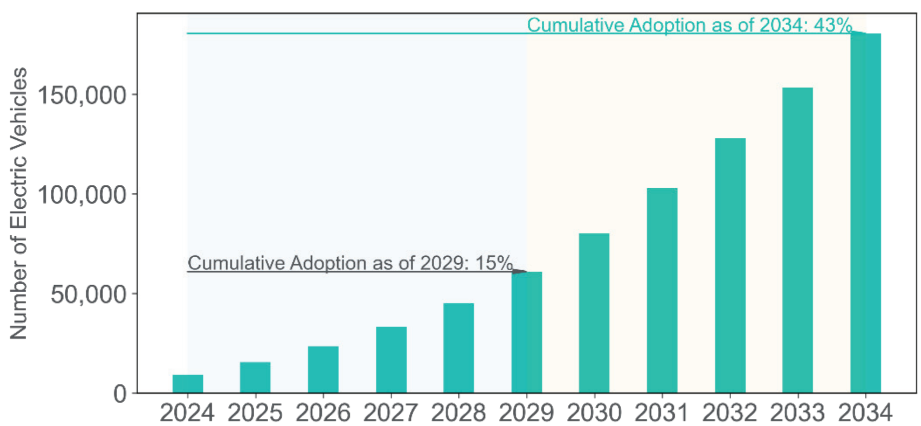
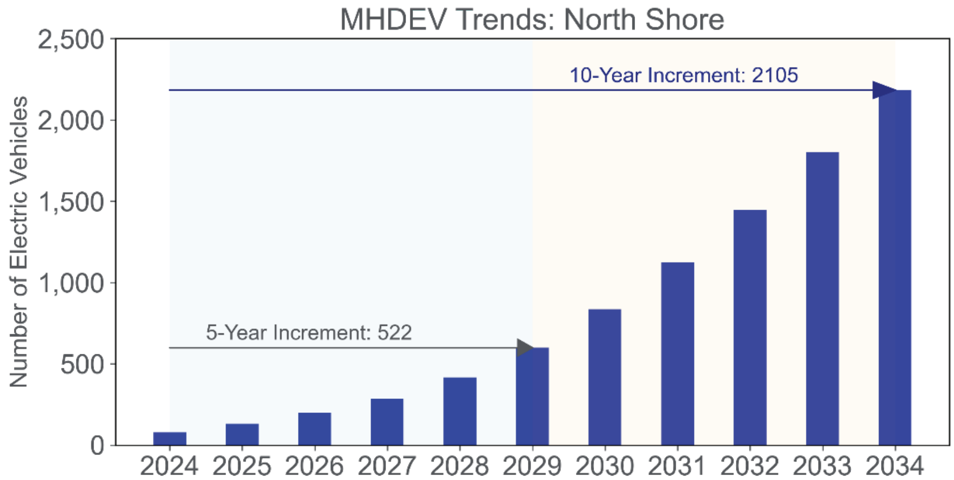


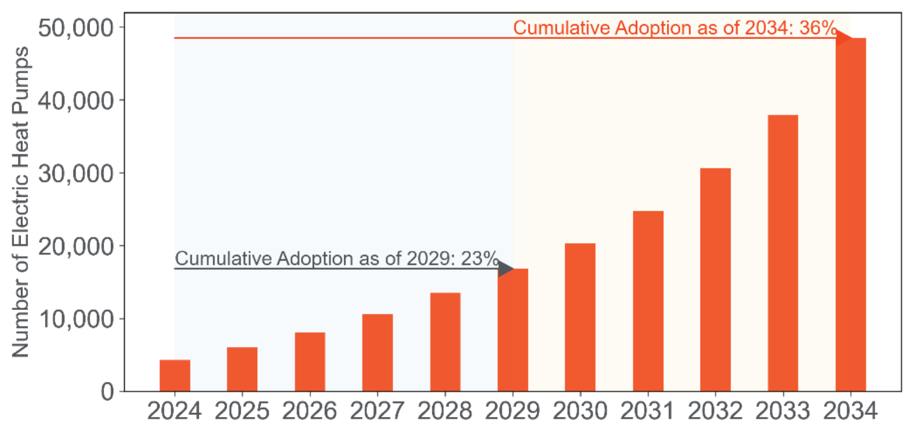
Exhibit 5.36: MHDEV Adoption Trend – North Shore Sub-Region



5.4.7 Heat Electrification

Among all six sub-regions, the North Shore has the second lowest EHP adoption trend forecast in the next decade owing to its low reliance on delivered fuel for heating. The total number of EHPs is set to rise to about 18,000 units by 2029 and exceed 50,000 by the end of 2034, resulting in about 36% overall penetration.

Exhibit 5.37: EHP Adoption Trend – North Shore Sub-Region



5.5 Southeast Sub-Region

5.5.1 Aggregate Demand – Summer and Winter

The Southeast sub-region is forecasted to have significant load growth due to an intermediate EV adoption trend.

Exhibit 5.38: Load Change from 2022-2029 – Southeast Sub-Region

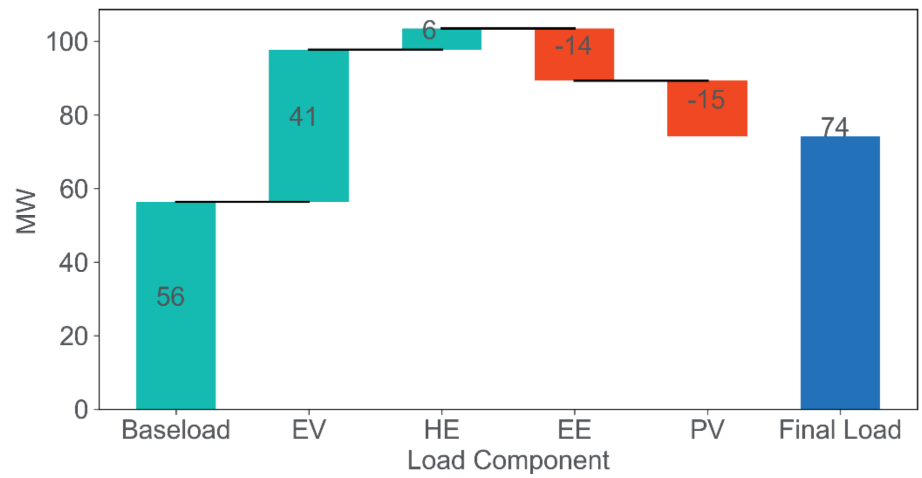
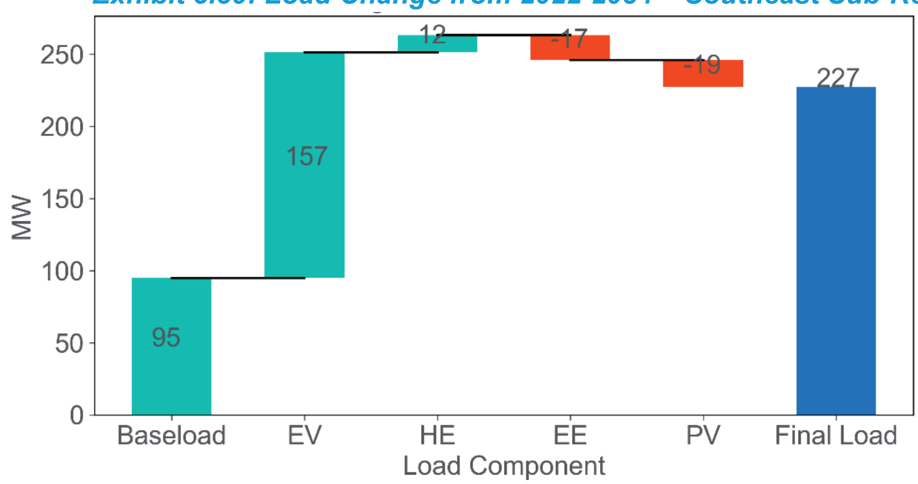


Exhibit 5.39: Load Change from 2022-2034 – Southeast Sub-Region



5.5.2 Weather Normalized Econometric Forecast

The Southeast sub-region falls primarily into the Southeastern Massachusetts (SEMA) load zone. The forecast for the SEMA load zone is discussed in the Appendix. Overall, the SEMA load zone forecast shows a CAGR of 1.3% by 2029 and 1.2% by 2034. The Southeast sub-region is expected to experience an average 0.8% annual growth both by 2029 and through 2034, which makes the region's baseload grow the slowest of all the sub-regions.

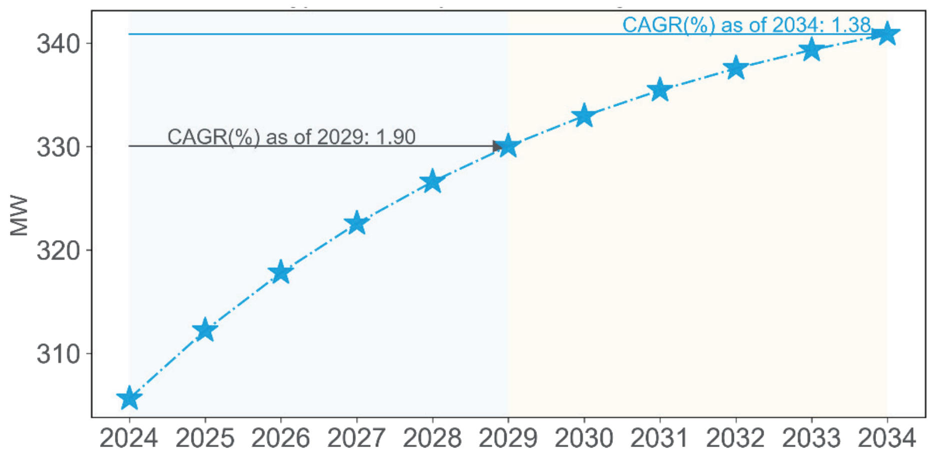
5.5.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.5.4 Energy Efficiency

In addition to the SEMA load zone, the Southeast sub-region falls partially into the WCMA ISO load zone. Both exhibit substantial overall electricity demand. The EE saving projection is expected to grow steadily from current savings of approximately 300 MW and accumulate throughout the decade, with about 341 MW of peak demand savings by the end of 2034.

Exhibit 5.40: EE Peak Savings – Southeast Sub-Region



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

Strong PV growth is expected in the Southeast sub-region based on current projects in the queue as well as parcel analysis and the nature of the area being predominantly suburban. The Company forecasts that the cumulative non-rooftop solar nameplates will rise to approximately 420 MW by the end of 2029 with an additional 116 MW of projects realized by 2034. Rooftop solar PV also will experience steady growth, reaching 275 MW before the end of 2034. See Exhibits 5.41 and 5.42 for a graphical representation of rooftop solar and non-rooftop solar trends, respectively.

Exhibit 5.41: Rooftop Solar Adoption Trends – Southeast Sub-Region

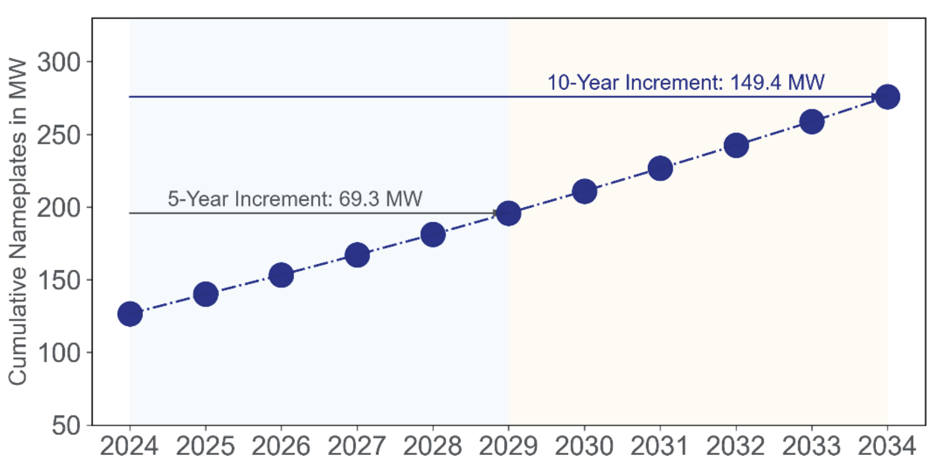
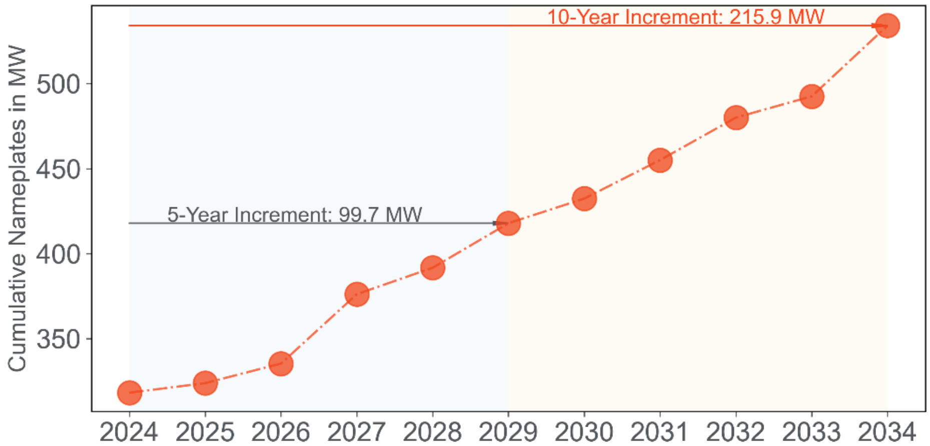


Exhibit 5.42: Non-Rooftop Solar Adoption Trends – Southeast Sub-Region



5.5.6 Electric Vehicles

The overall EV sales trend in the southeast sub-region is projected to grow in alignment with the recent market outlook as well as the Commonwealth's targets. By the end of 2034, the Company's forecasts show that about 200,000 LDEVs and about 4200 MHDEVs will be in operation in the sub-region. See Exhibits 5.43 and 5.44 for a graphical representation of LDEV and MHDEV trends, respectively.

Exhibit 5.43: LDEV Adoption Trends – Southeast Sub-Region

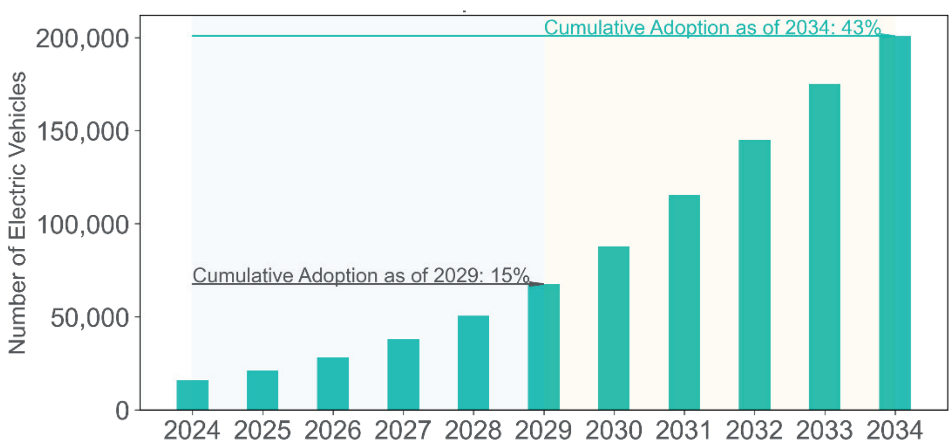
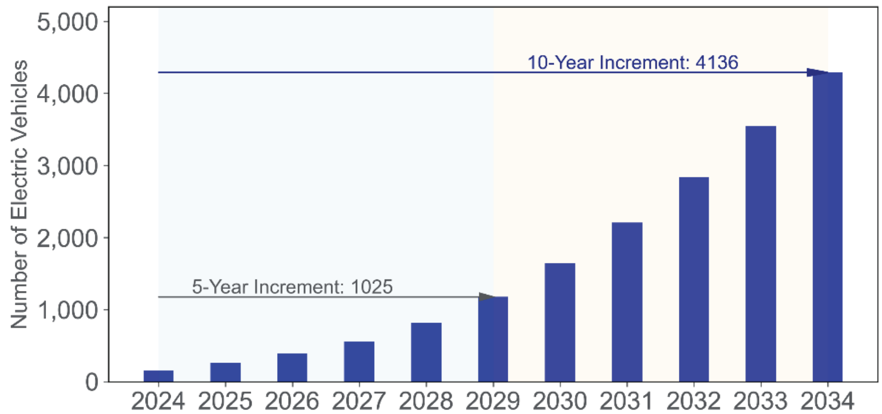


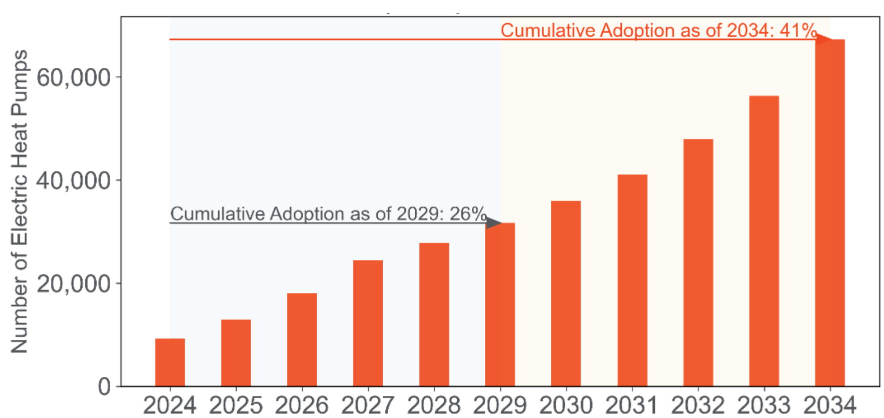
Exhibit 5.44: MHDEV Adoption Trends – Southeast Sub-Region



5.5.7 Heat Electrification

The Southeast sub-region currently has the most EHPs currently installed, and EHP growth is expected to continue in the sub-region through 2029, leading to an overall 26% heating electrification rate and 41% penetration before 2034. See Exhibit 5.45 below for a graphical representation of EHP trends.

Exhibit 5.45: EHP Adoption Trends – Southeast Sub-Region



5.6 South Shore Sub-Region

5.6.1 Aggregate demand – Summer and Winter

The South Shore sub-region's DER forecasts indicate relatively high growth in EV penetration, high EE savings, and moderate PV increases. The rapid EV growth will cause the region to switch from an afternoon to an evening peak hour sooner than other sub-regions. Exhibits 5.46 and 5.47 below show forecasted load change by 2029, and 2034, respectively.

Exhibit 5.46: Load Change from 2022-2029 – South Shore Sub-Region

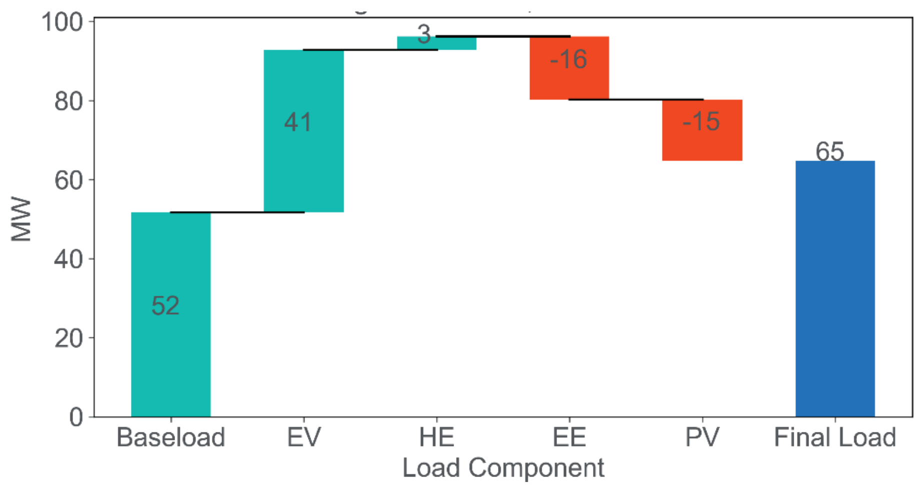
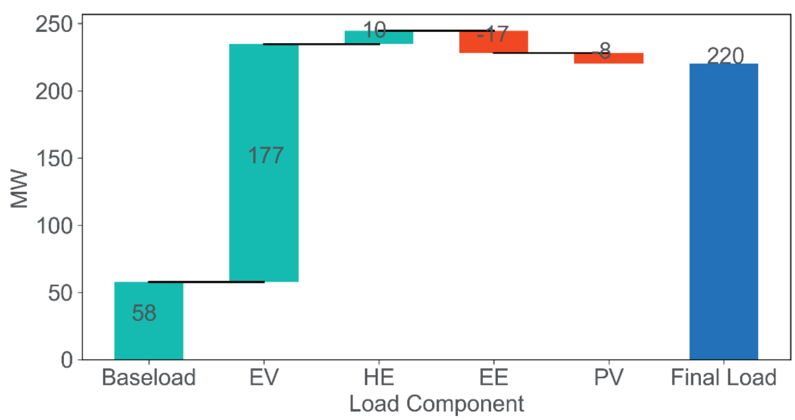


Exhibit 5.47: Load Change from 2022-2034 – South Shore Sub-Region



5.6.2 Weather Normalized Econometric Forecast

The South Shore sub-region is entirely within the SEMA load zone. The SEMA zonal forecast is discussed in the Appendix. Annual growth for the South Shore sub-region is expected to be moderate at 0.8% by both 2029 and 2034; the least significant growth pattern of all sub-regions.

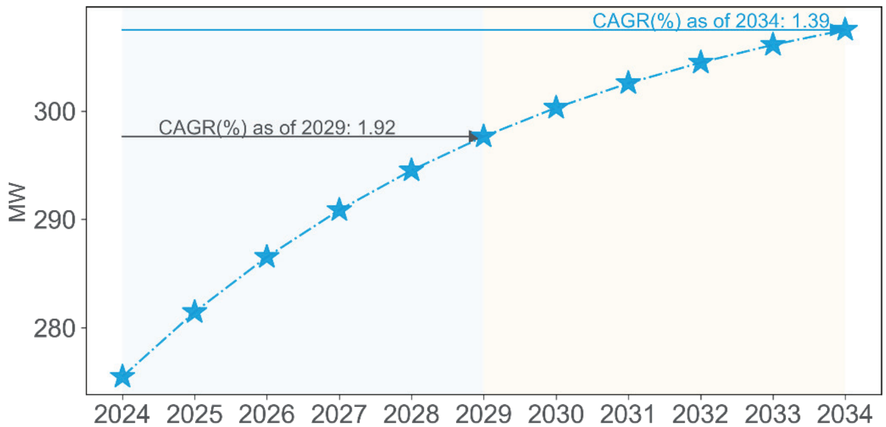
5.6.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.6.4 Energy Efficiency

The South Shore sub-region's EE saving trend is largely associated with the SEMA zonal EE forecast. Due to the current substantial peak demand, peak savings are expected to increase to about 300 MW by the end of 2029 and 310 MW by 2034. Exhibit 5.48 below shows expected growth in EE savings for the sub-region.

Exhibit 5.48: EE Peak Savings – South Shore Sub-Region



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

Rooftop solar is anticipated to grow continuously through 2034 in the South Shore sub-region and approach cumulative installation of 300 MW. In terms of ground mounted PV, given that the region has fewer DG projects in the queue than other sub-regions and that it has less availability of cost-effective parcels compared to other sub-regions, only mild growth is expected, eventually reaching 180 MW around 2034. Exhibits 5.49 and 5.50 below show expectations for rooftop PV and other PV, respectively.

Exhibit 5.49: Rooftop Solar Adoption Trends – South Shore Sub-Region

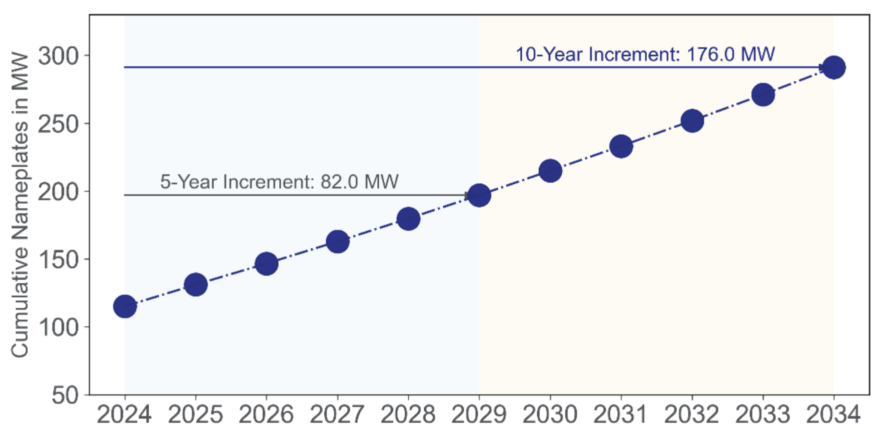
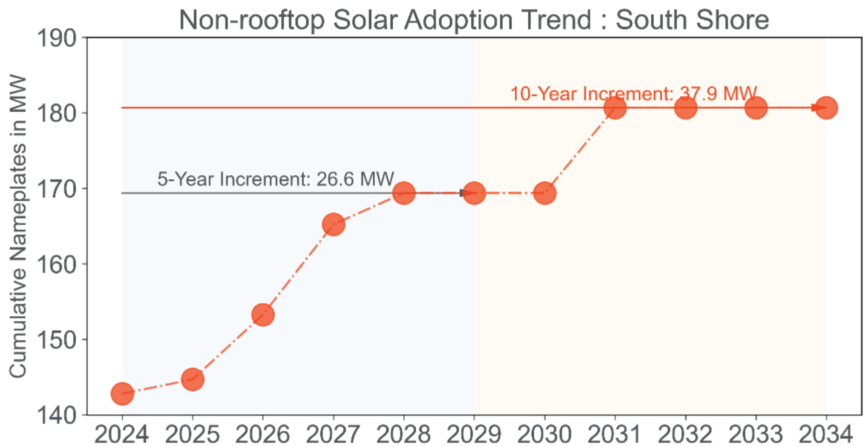


Exhibit 5.50: Non-Rooftop Solar Adoption Trends – South Shore Sub-Region



5.6.6 Electric vehicles

Significant EV growth is expected to take place in the South Shore sub-region owing to local socioeconomics and large commercial customer counts. The LDEV ownership percentage is forecasted to reach 50% (with about 240,000 vehicles) by the end of 2034 while, for MHDEV, the number of vehicles is expected to surpass 3,500 around the same time. Exhibits 5.51 and 5.52 below show expectations for LDEV and MHDEV trends, respectively.

Exhibit 5.51: LDEV Adoption Trends – South Shore Sub-Region

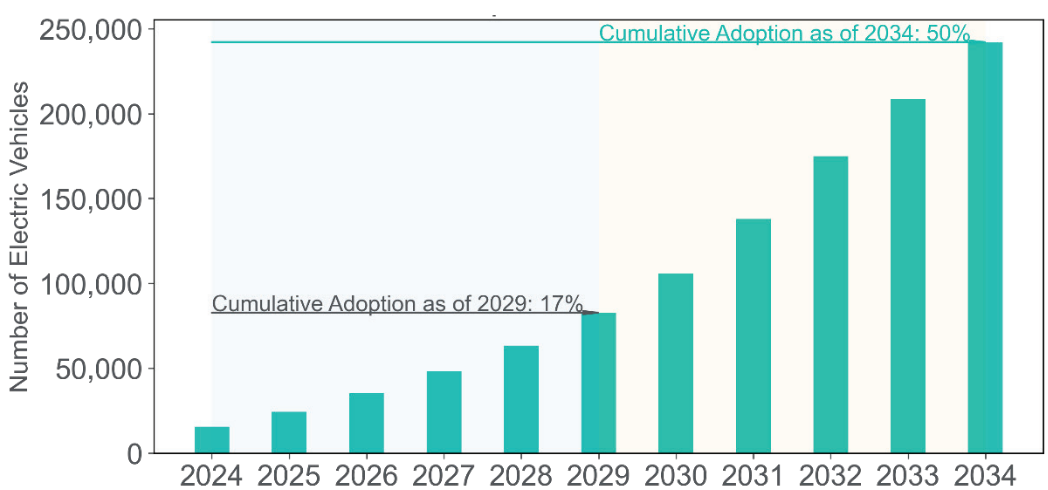
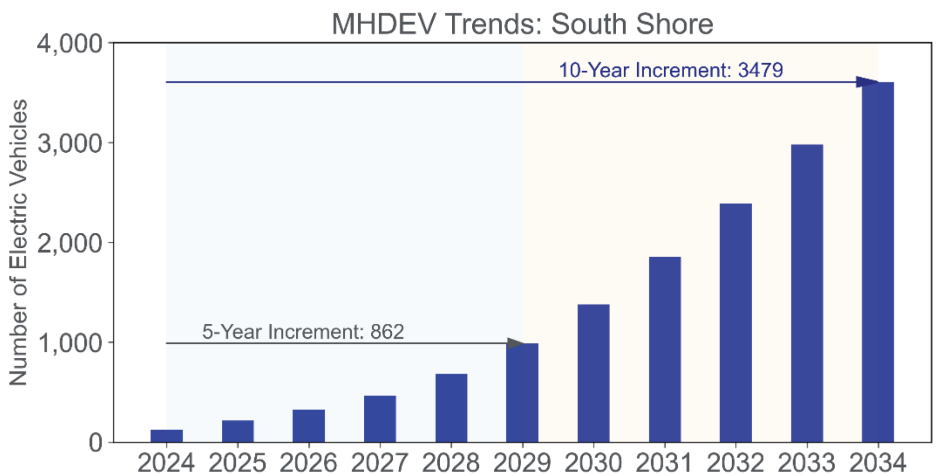


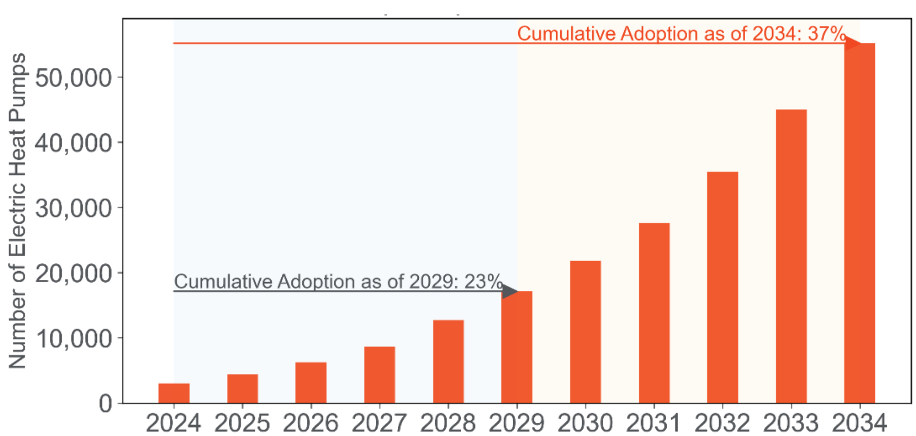
Exhibit 5.52: MHDEV Adoption Trends – South Shore Sub-Region



5.6.7 Heat Electrification

Moderate heating electrification is expected to take place in the South Shore sub-region between 2024 and 2034, with an overall 23% adoption by 2029, and 37% by the end of the 10-year horizon. Exhibit 5.53 below illustrates this trend.

Exhibit 5.53: EHP Adoption Trends, South Shore Sub-Region



5.7 Western sub-region

5.7.1 Aggregate Demand – Summer and Winter

The Western sub-region has the smallest electric load demand and is expected to have strong load growth with significant DER adoptions especially in PV and EV. Exhibits 5.54 and 5.55 below show expected load growth changes for the sub-region by 2029 and 2034, respectively.

Exhibit 5.54: Load Change from 2022-2029 – Western Sub-Region

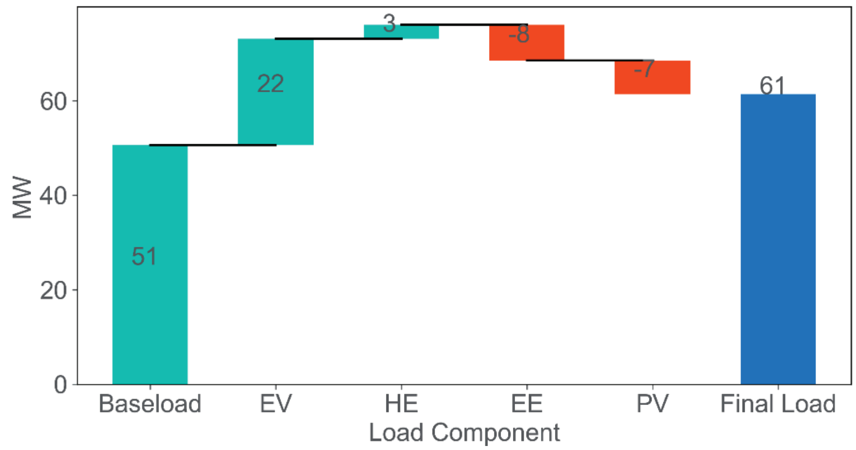
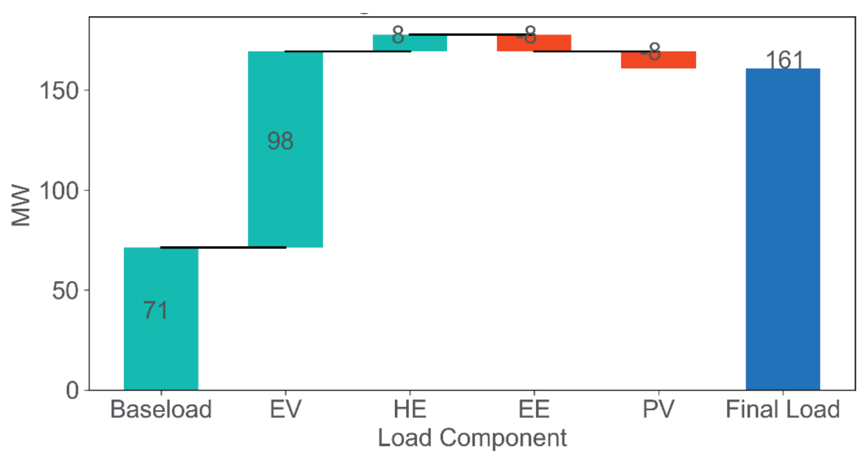


Exhibit 5.55: Load Change from 2022-2034 – Western Sub-Region



5.7.2 Weather Normalized Econometric Forecast

The Western sub-region falls entirely into the WCMA load zone. The forecast on WCMA is discussed in the Appendix. Overall, the WCMA load zone is expected to experience a CAGR of 1.2% by 2029 and 1.1% by 2034. The Western sub-region is expected to average 2.1% annual growth by 2029, and 1.8% through 2034. This is the highest econometric growth rate of all sub-regions.

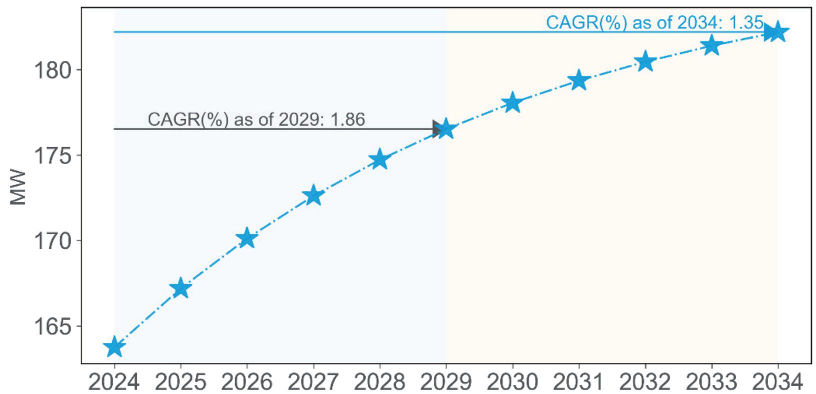
5.7.3 Large Load (Step/Spot Load)

Large load (step/spot load) impact is developed and handled in the system planning process. Please refer to Section 6 of this plan for further discussion.

5.7.4 Energy Efficiency

EE savings in the Western sub-region are moderate overall due to the sub-region's low energy consumption. The EE savings trend follows the same steady growth pattern as ISO-zone WCMA as a whole. The CAGR is 1.9% ending in 2029, and 1.4% for the Company's 10-year horizon ending in 2034, resulting in the sub-regional EE savings rising from 164 MW to about 182 MW. Exhibit 5.56 below illustrates the expected trend.

Exhibit 5.56: EE Peak Savings – Western Sub-Region



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

Due to the smaller number of customers in the Western sub-region, the Company forecasts a 5-year incremental growth in rooftop solar PV of 31.2 MW, and a 10-year incremental growth of 69 MW when compared to 2024. In terms of non-rooftop solar, the Western sub-region has sufficient cost-effective parcels, boosting projections of non-rooftop solar PV growth. Based on current project queue information, the sub-region is projected to have incremental growth of 126.8 MW in non-rooftop solar PV through 2029 and 385.8 MW by the end of 2034, leading to 800MW of solar projects in total when rooftop and non-rooftop PV are combined. Exhibits 5.57 and 5.58 below illustrate trends for rooftop solar PV and non-rooftop PV, respectively.

Exhibit 5.57: Rooftop Solar Adoption Trends – Western Sub-Region

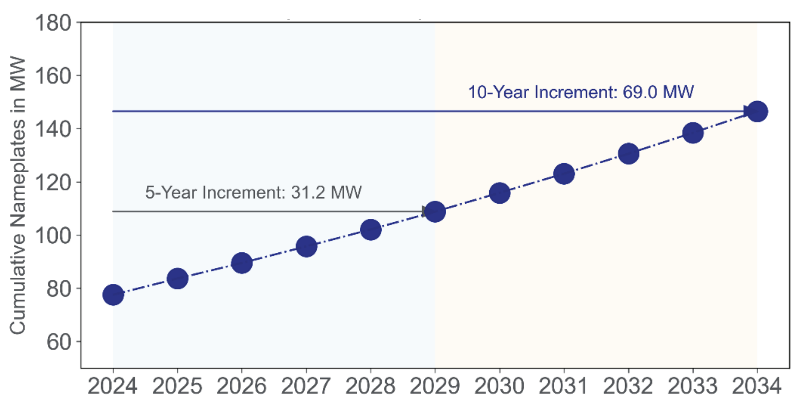
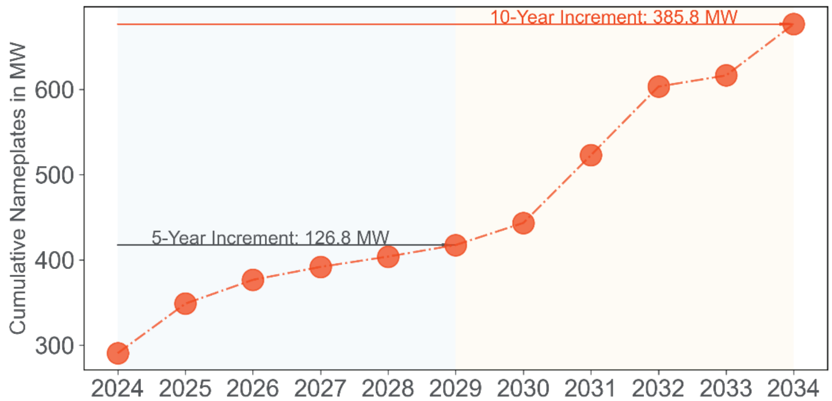


Exhibit 5.58: Non-Rooftop Solar Adoption Trends – Western Sub-Region



5.7.6 Electric Vehicles

As one of the least populous regions within the Company's service territory, the Western sub-region is projected to witness the adoption of approximately 30,000 additional LDEVs between 2024 and 2029, resulting in an estimated 14% market share for LDEVs by the end of 2029. Continuing this upward trajectory with greater growth trends, LDEVs in the Western sub-region are forecasted to account for about 50% of all light duty vehicles in operation by the end of the 10-year forecast horizon. The MHDEV trend exhibits a similar pattern with about 2,300 MHDEVs by the conclusion of 2034. Exhibits 5.59 and 5.60 below illustrate these trends for LDEVs and MHDEVs, respectively.

Exhibit 5.59: LDEV Adoption Trends, Western Sub-Region

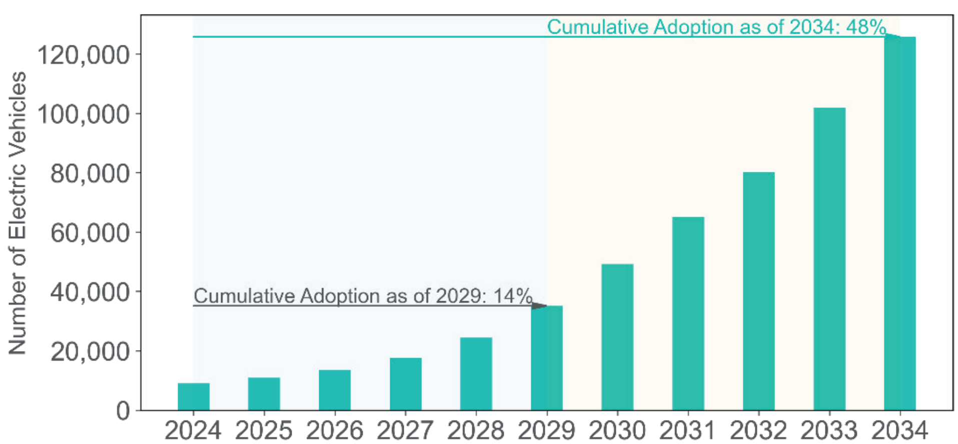
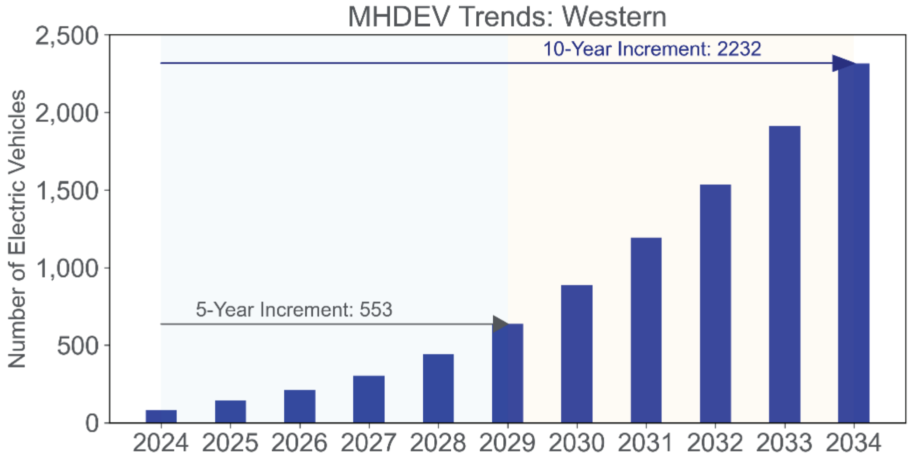


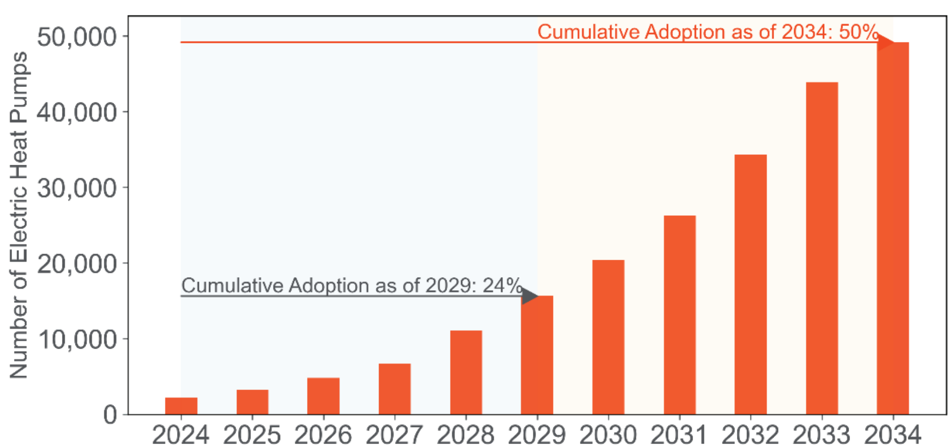
Exhibit 5.60: MHDEV Adoption Trends, Western Sub-Region



5.7.7 Heat Electrification

Because a significant share of households in the Western sub-region use delivered fuel for heating, the Western sub-region is expected to witness rapid growth of EHP adoption in the next decade. The overall adoption rate of EHPs for residents within this sub-region is forecasted to reach 24% by the end of 2029, and 50% for 2034.

Exhibit 5.61: EHP Adoption Trends – Western Sub-Region



Section 6

5- and 10-Year Planning Solutions: Building for the Future

This section describes the new investments and programs that the Company proposes to implement over the next five and ten years and how they will create value for customers and accelerate delivery of the Commonwealth's Net Zero commitments.

Key Take-Aways

- Over the period from 2025-2034, the Company expects considerable growth in customer load due to electrification of transportation and heating and significant adoption of DERs like solar and ES to keep pace with the Commonwealth's Net Zero targets.
- The current network is not big enough to meet this growth. It takes multiple years to develop, design, and deliver electric network infrastructure investments, and so proactive investments in a stronger network must be made now.
- The network infrastructure investments will address the imminent capacity deficiencies in the short-term with appropriately scoped solutions to support the long-term energy needs as customer electrification and clean energy resource adoption accelerates into the future.
- Not only will the electric network need to be stronger, it will also need to be smarter as the Company manages a more complex and dynamic network. The Company will build on the progress of Grid Modernization investments to develop a complementary set of advanced technological capabilities required to manage a more dynamic, reliable, and DER-heavy network that supports new customer offerings.
- The Company will leverage its new technology capabilities and customer offerings to accelerate the adoption of clean energy technologies by delivering NWA that will both defer the need for investment and support the continued connection of customers' EVs and EHPs at pace as we continue to build out the network.
- While implementing those network infrastructure projects, new programs and scaled existing programs will be deployed to empower the Company's customers to participate in the clean energy transition, both by helping them install and adopt clean energy technologies like EVs, EHPs, and EE, and by creating opportunities for them to take more ownership of their bill via new rate structures and programs that value customer flexible demand.
- To deliver at the pace required the Company will need to work differently, and it will also need regulatory, policy and permitting changes to enable the quicker delivery of these critical investments.

6.0 5- and 10-Year Planning Solutions: Building for The Future

The purpose of this Section is to describe the 5- and 10-year investments and programs that the Company plans to deploy to meet customers' evolving needs and to keep pace with delivery of the Commonwealth's 2050 Net Zero goals as outlined in the CECP. As explained below, these investments are essential to meet imminent and forecasted capacity needs. These investments fall under three categories – network infrastructure investments, technology platforms, and customer-facing programs. This Section will:

- Provide a comprehensive outlook of investments and programs that are already in-flight and/or approved via prior regulatory proceedings.
- Outline more detailed proposed investments and programs that the Company introduces for the first time or intends to scale as part of this Future Grid Plan.

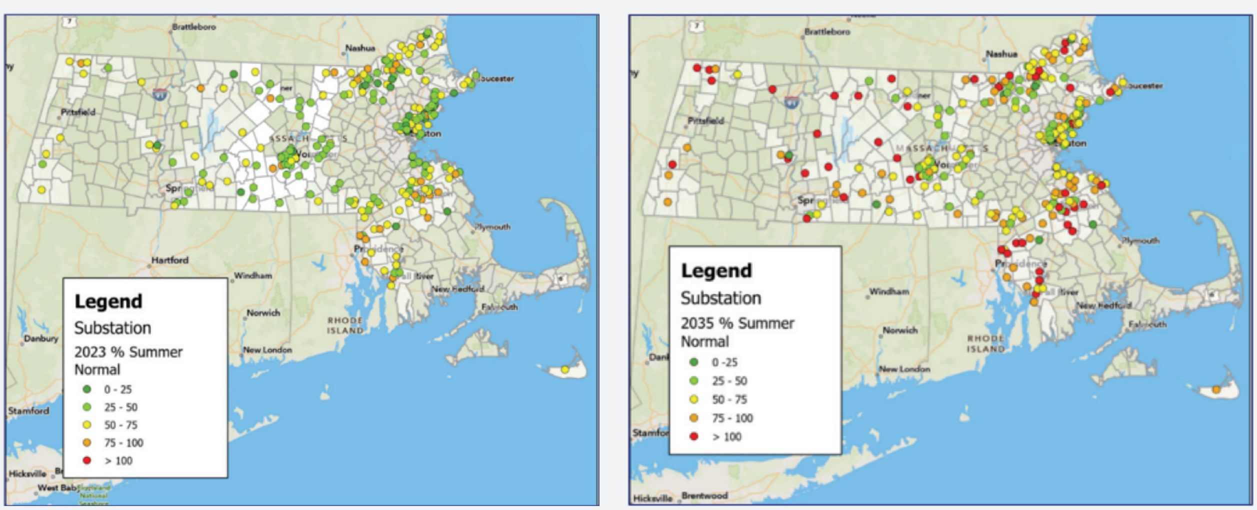
These investments and programs all come together to deliver the network of the future with capabilities from each investment building on the others to create a smarter, stronger, cleaner grid for all Company customers.

Shortfalls to Meeting 2050 CECP Clean Energy Goals Absent Long Term Investment

To meet the CECP's ambitious 2050 objectives and interim goals, the Company must make appropriate investments now to expand the capacity on its electric distribution system. In Section 5, the Company forecasted peak load growth based on CECP targets and other relevant policies. The projected load growth on the network, driven by the adoption of electric transportation and heating, is expected to increase peak load across the network by 8% in 2029 and 26% by 2034 relative to 2022 levels.

Capacity deficiencies are beginning to arise in the network's current state and will only be exacerbated in the future, driven by increased electrification and clean energy policies. Absent investments to expand network capacity, the Company has identified shortfalls in its ability to continue to provide safe and reliable network operations as the capacity needs grow to support the Commonwealth's clean energy generation and electrification targets, illustrated as follows:

Exhibit 6.1: Substation Loading in 2023 and 2035 Absent Capacity Expansion



Delivering the Capacity Needed to Support the Commonwealth's Clean Energy Goals

To address the identified capacity deficiencies, the Company has proposed investments in this Plan, which include augmenting existing or adding new substations. These projects will address the imminent capacity deficiencies in the short-term with appropriately scoped solutions to support the long-term energy needs as customer electrification and clean energy resource adoption accelerates into the future, thus enabling the Commonwealth to keep pace with its ambitious and important 2030 through 2050 clean energy and climate goals.

- The Company's 5-year investment plan includes delivery of 13 substation upgrades or rebuilds by 2029, enabling over 800 MW of capacity (to serve load and host DER).
- The Company's 10-year investment plan includes an additional six substation upgrades and delivery of 26 new or rebuilt substations by 2034, enabling over an additional 2,900 MW of load-serving capacity and DER hosting capacity, for a total of almost 4 GW of additional enabled capacity to interconnect DER and load by 2034.

Exhibit 6.2 below demonstrates how, in aggregate, these network investments increase the load-serving and hosting capacity across the system on an annual basis. The details of these investments by subregion are found in Section 6.5 through Section 6.10.

Exhibit 6.2: Summary of Proposed Investments and Programs

	2028	2029	2030	2031	2032	2033	2034	Total
Enabled Substation Capacity (MW)	143	672	0	353	551	199	1,852	3,769

In addition to the load-growth driven network infrastructure projects above, the Company's Plan includes three DER-enablement CIPs to address interconnection group studies. The CIP projects include four substation upgrades, resulting in 244 MW of additional capacity to be in-service by 2029. While the underlying impetus for these projects is based on group studies related to DER interconnection projects in-queue, this capacity will similarly be multi-use, meaning that it will be able to support the adoption of electric vehicles and heating, as well as future interconnections of new solar and energy storage.

Enabling Adoption of Electric Vehicles and Electric Heating

Overall, the Company's ESMP includes delivery of approximately 4,000 MW of substation capacity, all of which will enable the headroom required to readily connect new customer loads from electric vehicles and electric heating in support of the Commonwealth's clean energy targets.

To complement the physical network infrastructure investments, the Company's Plan includes several proposed investments and programs aimed at accelerating the adoption of electrification technologies by resolving customer frictions across the end-to-end customer connections process. These cover a broad range, including (but not limited to):

- Extending the Company's EV Phase III programs and incentives, reducing the cost and complexity for customer EV adoption across all customer segments
- Enhancements to customer portals to improve customer rebates and incentive programs experience
- Deploying technology investments to enable flexible interconnections for EVs
- Enabling new opportunities for customers to create additional value from their flexible devices through virtual power plants as Non-Wire Alternative (NWA) solutions and as part of wholesale market resources via FERC 2222

Enabling Interconnection of Solar and Storage

The 4,000 MW of substation capacity included in the Company's Plan is multi-use meaning that it will also enable headroom to readily interconnect new solar and storage customers. This is on top of the over 2.3 GW of solar and storage projects connected to the Company's network today.

To complement the physical network infrastructure investments, the Company's Plan includes several proposed investments and programs aimed at accelerating the adoption of solar and storage technologies by mitigating developer frictions across the end-to-end interconnections process. These cover a broad range, including (but not limited to):

- Enhancements to customer portals and hosting capacity maps to improve the speed and transparency of the interconnection process, including a focus on same-day approvals for residential customer interconnection applications.
- Technology investments, including DERMS, to expedite the interconnection study process
- Extending the CIP cost allocation methodology to future group studies so that DER applicants do not bear the full cost of multi-value system upgrades.
- Scaling Flexible interconnections for solar, storage, and EVs beyond the Company's initial pilot.
- Enabling new opportunities for customers to create additional value from their solar and storage through virtual power plants as Non-Wire Alternative (NWA) solutions and as wholesale market resources via FERC 2222.

Summary of Proposed Investments

The 5- and 10-year investment plan described in this Future Grid Plan is designed to meet the near-term demand projected in the Company's 5- and 10- year forecasts, as well as align investments with the long-term demand in the 2035-2050 assessment. The Company's proposed investments are designed to support the Commonwealth's interim and long-term clean energy and climate goals and meet customers' evolving needs. The Company proposes three categories of investments:

- **Network Investments** must begin now to account for the lengthy construction timelines for electrical infrastructure. This category includes substation and feeder expansion projects that will increase the capacity of the electric distribution system. This increased capacity will be needed to proactively address expected overloads and maintain safe and reliable network operation to keep pace with increased electrification of heating and transportation. The increased capacity on the system will be "multi-value," meaning that it will create additional headroom for both new load from electric heating and transportation, as well as for new DER interconnections. The analysis and proposed infrastructure investments are presented by sub-region in **Section 6.4 through Section 6.10.**
- **Platform Technology Investments** as described in **Section 6.3** are the critical enabler that will help maximize the value of the customer and network investments as the network grows in complexity and the Company offers a larger and more diverse set of customer clean energy offerings. The Future Grid Plan includes investments to further scale the Company's recently approved Grid Modernization investments to deliver more benefits for customers, as well as new

investments in critical technology capabilities to manage DERs and activate customer flexibility both to reduce the need for network buildout and to achieve more dynamic network operations. Additionally, the Company is building supporting capabilities related to data capture and management, security, and new digital tools, that will further accelerate the pace and delivery of network infrastructure projects.

- The clean energy transition will not happen without the active engagement of end-use customers – residential, commercial, and industrial. The **Customer Investments and Programs** described in **Section 6.11** are intended to make it easier for customers to participate in the clean energy transition, including initiatives that will help reduce the costs and complexity for customers to adopt and install DERs such as Electric Heating (EH), EVs, Energy Efficiency (EE), Energy Storage (ESS), and Solar PV. These initiatives also include ways for customers to take greater ownership of their bills through enhanced insights into how they use energy, new rate options, and expanded opportunities to earn value as "prosumers" via grid service programs (Non-Wire Alternatives or NWAs), which will become increasingly important to the Company's delivery of a clean energy network.

Given the length and level of detail included in Section 6, Exhibit 6.3 below functions as a Section 6-specific table of contents, organized by investment category for investments and programs proposed in the ESMP. These same investment categories and groupings are used in the costs and benefits summaries included in Section 7.

Exhibit 6.3: Summary of Proposed Investments and Programs

Investment Category	Investment Category Description	Investment / Program	Described in Sub-section
Network Investments	New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology to improve network operations and management	Substation and distribution line upgrades	6.5-6.10
		Expanded CVR/VVO	6.3.2.1.4
		Early Fault Detection	6.3.2.1.5
		Integrated energy planning	6.3.2.6, 11.0
		Warehouse expansion to support incremental workplan	6.12
		Company EV Fleet Infrastructure Acceleration	6.12
ESMP - CIP	Substation and line upgrades to enable DER interconnections with cost allocation	Substation and distribution line upgrades*	6.5-6.10

Customer Investments and Programs	New programs and demonstrations to advance VPPs and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies	Incentives for Energy efficiency, demand response, electric heat pumps*	6.11.1.1
		Flexible connections	6.11.1.3, 6.11.1.4
		New customer NWA programs	6.11.2
		Metering & billing systems	6.3.2.3
		Customer portals for clean energy programs	6.3.2.4
		Time-varying rates*	6.11.1.5
		Resilient neighborhoods*	6.11.3.1
EV Programs	Continuation of existing EV make ready and charging infrastructure enablement programs	EV Phase III Program Extension	6.11.1.2
Platform Investments	Investments identified to leverage data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs	Network management technology investments	6.3.2.1
		Communications infrastructure	6.3.2.2
		Data management investments	6.3.2.5
		New digital products to support asset planning, management and work execution needs for clean energy investments	6.3.2.6
		Enhanced security investments	6.3.2.7

*Described in ESMP for completeness, but to be formally proposed and funded outside of ESMP.

6.1 Summary of Existing Investment Areas and Implementation Plans (Existing Asset Management and Base Spending, Including Rate Case, Grid Modernization, Approved CIP Programs, Decarbonization, Heating, Electric Vehicle and Energy Efficiency Programs)

This Section summarizes existing investment areas, programs, and initiatives that have been approved in prior filings or are pending approval in current dockets. The table below includes descriptions of some of the key investments and where applicable includes links to the relevant dockets and filings.[1]

[1] Note, the Company has previously provided the GMAC with a summary of relevant dockets: https://www.mass.gov/doc/gmac-mtng-4-preread-esmp-relevant-proceedings-and-working-groups-version-2/download

Exhibit 6.4: Summary of Approved Investments and Programs

Investment Area	Summary of Approved Investment / Program
Base Spending – Electric Operations	The Company's base spending capital investment activities (i.e., "core") cover a range of project categories required to maintain safety and reliability of the network under relatively status quo conditions. The Company's base spending capital investment are described more completely in Section 7.1. In summary they include: ▸ **Asset Condition**, including substation replacements and retirements, implementation of the Inspection and Maintenance program and the proactive replacement of direct-buried underground cables. ▸ **System Capacity and Performanc**e, including large substation expansions necessary to increase area capacity and the transformer replacement program. ▸ **Damage Failure**, including projects necessary to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. ▸ **Customer Requests/Public Requirements** which are investment requirements that the Company has an obligation to fulfill, but which are not under the Company's control. ▸ **Non-Infrastructure**, which represents capital investment that does not fit into one of the foregoing categories, but which is necessary to run the electric system.
Grid Modernization Plan (GMP)	The collective technology investments and demonstrations outlined below will significantly modernize the Company's network management and communications capabilities, ability to operationalize data to transform how the network is operated, as well as security. The Company received approval on its second GMP (for the years 2022-2025) via two separate Orders in October and November 2022. The Orders authorize investments in the following: ▸ **ADMS:** enabling real-time management and control of the Company's electric distribution network. ▸ **Feeder monitors**: enabling real-time visibility into the Company's electric distribution network. ▸ **Advanced Distribution Automation / Fault Location Isolation Service Restoration (FLISR):** system that identifies and automatically resolves problems on the distribution system improving system reliability, reducing customer outage time, and increasing customer satisfaction. ▸ **Conservation Voltage Reduction (CVR) and Volt/Volt-Amps Reactive Optimization (VVO):** system that optimizes distribution system voltage, resulting in reduced energy demand and lower costs to customers. ▸ **Communications:** Secure and reliable communications networks to meet customer and Company needs.

	- **Information technology, data management and integration, and security:** improving the technology foundation to deliver, "any data, any service, any time" via data management and analytics, integration services, and cyber security investments. - **Distributed Energy Resource Management Systems (DERMS):** used to plan, track, manage and operate DERs. The system includes features such as short-term forecasting, grid edge control, DER dispatch, and market platform. - **Active Resource Integration (ARI) solar demonstration projects** to field test DERMS capabilities to deliver a new flexible interconnection option to accelerate DG interconnections. - **Local export power control demonstration projects** to reduce interconnection cost and time for customers adding load and generation on the system at the same time. The solution locally manages the customer assets so it has defined net impact on the system.
Advanced Metering Infrastructure (AMI)	The Company received approval for its AMI plan in 2022. The order authorizes the Company to replace its existing Automated Meter Reading (AMR) meters and supporting systems with AMI. The AMI plan includes the widescale deployment of smart meters across the network and accompanying back-office technology that will transform the ways in which Company customers can access their energy usage data and manage their energy consumption, as well as improve the ways in which the network is operated and planned. The deployment of AMI will be implemented on a rolling basis and is expected to be fully complete by the end of 2027.
Energy Efficiency (EE)	The Company's most recent three-year EE plan (2022-2024) authorizes the Company to administer various EE, Demand Response (DR), and Electric Heat Pump (EHP) incentives programs as part of Mass Save, investing $1.28B for electric EE and $0.67B for gas EE. These programs provide bill savings benefits for participating customers and broader social benefits (such as those from peak shaving) that benefit the Company's overall customer base. - EE – the Company administers a comprehensive set of nation-leading incentive programs designed to help customers across all segments identify energy inefficiencies in their homes and businesses and address those inefficiencies by leveraging rebates to install new measures to reduce their energy consumption. - DR – program that incentivizes commercial, industrial, and residential customers to curtail and/or shift their energy when the electricity demand is forecasted to be at its peak. The Company administers several DR programs via ConnectedSolutions focused on reducing load across the network when the collective network is at peak. The programs include thermostats, ES, EVs, and large curtailable loads at Commercial and Industrial facilities. - EHP Incentives – program that offers rebates based on equipment capacity to residential and commercial customers who install EHPs, to supplement or replace a pre-existing oil, propane, natural gas, or electric resistance heating systems.

Electric Vehicles (EVs)	The EV Phase III Program approved in Dec 2022 and covering Jan 2023 through Dec 2026 is a comprehensive set of offerings designed to support the growth of EVs in the Commonwealth, including: ▸ Residential: incentives to provide at-home electrical upgrades, charger installations, and off-peak charging (includes individual residential customers and multi-unit dwellings). ▸ Public and Workplace: make-ready, charger, and networking incentives to enable widespread access to charging across communities. ▸ Fleet: make-ready and charger incentives to assist with electrifying fleet vehicles, including light-, medium-, and heavy-duty, as well as fleet advisory services. ▸ Demand Charge Alternative Program (2023-2032): a program helping to reduce the operating costs of fast chargers and accelerate deployment. Provides a tiered load factor-based demand charge discount to separately metered EV charging customers.
▸ **Pending Capital Investment Plans (CIPs)**[2]	The Company has proposed a set of capital investments required to interconnect solar PV and ESS projects in specific areas with a cost allocation methodology that reflects the multi-value nature of projects. The Future Grid Plan network infrastructure analysis and resulting proposed investments assume that the Company's pending CIP proposals are approved. The specific CIP proceedings that are underway have been identified for each sub-region in Section 4.

Customer Programs to Address EJCs

The Company recognizes that populations in EJCs may face barriers to participation in programs that help manage bills or provide opportunities for customer participation in the clean energy transition. The Company's existing customer programs, such as its successful EE and EV programs, have benefited from the input of EJCs to inform program design that reflects community priorities. For example, engagement through the EE Equity Working Group has played a crucial role in establishing specific goals for equity and service for EJ populations. For EE and EV programs, more enhanced EJC incentives are offered for residential customers and more direct support of fleet electrification is a priority to reduce local air pollution. The Company will continue to engage with EJCs about future customer program designs, as well as with other stakeholders. The Company's Equity and Environmental Justice Policy and Stakeholder Engagement Framework is in the Appendix.

[2] See D.P.U. 22-61, D.P.U. 22-170, D.P.U. 23-06, D.P.U. 23-09, and D.P.U. 23-12.

Exhibit 6.5: Summary of Existing EJC Incentives/Offerings

Program	EJC Incentive / Offering
EVs – Public Fleet Infrastructure rebates for EJCs	‣ Up to 100% utility-side infrastructure incentives ‣ Up to 100% customer-side infrastructure incentives ‣ Up to 100% charger rebates for income-eligible EJCs; Up to 75% charger rebates for other EJCs; ‣ Up to 50% charger rebates for non-EJCs
EVs – Residential EV Charging incentives for EJCs	‣ Up to $1000 rebate for in-home EV charging infrastructure upgrade when enrolling in managed charging program for single family in an EJC ‣ (Up to $2000 rebate for 2-4 family)
EE upgrades for low-income customers and multi-family residents	‣ All eligible energy efficiency upgrades to low-income customers, and multifamily buildings with 50% or more low-income tenants, at no cost.
Weatherization for all rental units	‣ 100% no cost home weatherization for all rental units.

Note: See Exhibit 3.6 for a more complete description of programs for EJCs and LMI customers.

The Company acknowledges that there is no dedicated offering for LMI or EJC customers to participate in the benefits of solar energy. In February of 2021, the Company filed a proposal with the Department for the Solar Access Initiative, which aims to expand access to solar energy and provide annual bill discounts to up to 20,000 low-income customers in the Commonwealth.[3] The proposed program would reduce barriers to entry to community solar for low-income customers by eliminating the need for credit checks through a Solar Simplified Billing program, and also guarantee on-time payments to community solar project owners.

The Company was also actively involved, along with the other EDCs, in assisting the MA DOER with the development of its recent application for $250M of federal funding, via the US EPA's Greenhouse Gas Reduction Fund Solar for All Program. The program is intended to incentivize solar energy installations for a wide variety of types of low-income and affordable housing.

[3] Solar Access Initiative Proposal for Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 20-145.

6.2 Design Criteria Changes (If Applicable)

Common with all EDCs, the Company has Engineering Planning Criteria which set out when and how the network should be planned and built to meet its requirements. The Company utilizes Distribution Engineering Planning Criteria, which establish the standards by which planners evaluate issues such as thermal loading, voltage limits, protection analysis, and reliability, and set thresholds the planning engineers use to determine when a project is needed and how to appropriately size the solution to that need.

With increased electrification there will be growth in electric demand and a need for greater reliance on the system. Thus, the Company must design and operate a system that keeps pace with future changing needs. Today there are many capacity constraints on the system and keeping pace means the Company will need to build the system in an anticipatory manner by adding capacity so it is in place when and where customers need it. This will enable faster customer connections. Customers also will expect a system that is reliable such that they have power during adverse system condition events; examples include things such as a failure of a substation supply transformer or a storm event. This also requires building the system to more stringent Engineering Planning Criteria. As a result, the Company's Engineering Planning Criteria will continue to evolve.

6.3 Technology Platforms That are Being Implemented (Including AMI With Data Access, VVO, FLISR, ADMS, DERMS (To Optimize 20-Year Solution Set), Automated Interconnection Tools, Etc).

The Company proposes to build on its existing and in-progress technology platforms with new investments to support delivery of the Future Grid objectives. See Section 4.9 for a discussion of the technology platforms the Company has in place today. This Section provides an overview of technology platform investments necessary in the next 10 years, including: (1) investments approved in other dockets, which are identified to provide a holistic view of such investments, (2) investments approved in other dockets the Company proposes to extend in this ESMP, and (3) net new ESMP investments.

Consistent with the framework introduced in Section 4.9, technology investments are described in the following categories:

1. **Network management** includes the technologies used to communicate with, monitor, and control assets on the network, including company-owned assets and customer DERs, and technologies needed to manage and respond to grid outages and abnormal system conditions.

2. **Communications** includes telecommunications infrastructure investments to support the latency and security requirements of a dynamically managed and DER-heavy electric system.

3. **Metering and billing systems** include the technologies used to measure customer energy usage on the network and issue accurate bills based on those meter reads.

4. **Customer portals** include the customer-facing as well as internal systems used to support customer clean energy programs such as those related to EE, EV, and new customer interconnections. This bucket of technology investments helps to accelerate customer adoption of clean energy technologies and improve the customer experience.

5. **Data** includes the type of data that the network planning and operations teams, and customers, have access to, as well as the Company's ability to manage, integrate, and operationalize that data to transform how the grid is operated and planned.

6. **Asset planning, management, and work execution** includes the systems used to support grid planning and design, construction and capital deployment, and system maintenance and field operations.

7. **Security** includes measures in place to ensure the security of the technology systems from potential cyber threats and attacks.

Exhibit 6.6 below categorizes the needed technology investments that are in flight and already approved in a previous filing, as well as incremental investments proposed in the Future Grid Plan. All of these investments are included in the "Platform Technology" costs summarized in Section 7 unless otherwise noted in red text below.

Exhibit 6.6: Summary of Needed Technology Investments

#	Category	In-flight/Already Approved	Proposed in ESMP
1	Network Management	‣ ADMS ‣ DERMS Phase I ‣ VVO / CVR	‣ DERMS Phase II* ‣ Active power restoration services* ‣ Expanded VVO/CVR (Network Investments) ‣ Early Fault Detection (Network Investments) ‣ Future of network management demonstration projects*
2	Communications	‣ Grid modernization communications	‣ Expanded operational telecommunications infrastructure ‣ Secure integration with Enterprise network communications
3	Metering and billing systems (Customer Investments)	‣ AMI	‣ TVR billing system engine ‣ Markets settlement engine

4	Customer portals (Customer Investments)		▸ Clean Energy Platform 2.0 ▸ DER customer experience enhancements
5	Data	▸ Data management platform ▸ AMI	▸ Intelligent data capture ▸ Grid asset data enhancements ▸ Transactional digital twin
6	Asset planning, management, and work execution		▸ New digital products to support asset planning, management and work execution needs for clean energy investments
7	Security	▸ Foundational security investments	▸ Enhanced security investments

* Denotes investments where costs will be offset (either completely or in part) by the IIJA/GRIP award from the DOE for the "Future Grid Project."

In October 2023, National Grid was selected to receive a competitive grant from the US Department of Energy (DOE) under the Infrastructure Investment and Jobs Act (IIJA) via the Grid Resilience and Innovation Partnerships (GRIP) Program for the Company's proposed "Future Grid Project." [4] As described in Section 7.1.2, the grant will help support the Company's proposed platform investments in Massachusetts, which will result in customer benefits by not only helping to offset costs for the Company's network management technology investments, but also to accelerate new capabilities, included in this Plan and described below.

6.3.1 How We Deliver Technology in a Rapidly Evolving Industry

As the distribution network continues to evolve with the proliferation of DERs, EVs, and EHPs, so will the operational challenges and opportunities that face the network. Therefore, the Company is continually seeking innovative ways to deliver new products and services efficiently. As an EDC, the Company's challenge lies in adapting to the changing needs of customers while continuing to ensure secure, affordable, and safe electric service. To address this challenge, the Company has and continues to lead the energy transformation through the delivery of industry-leading digital products leveraging the Scaled Agile Framework (SAFe) shown in Exhibit 6.7. SAFe is an overarching framework for scaling agile practices across large organizations that allows for a streamlined process for product delivery. This system is currently being employed by the Company today and will help facilitate the adoption of many

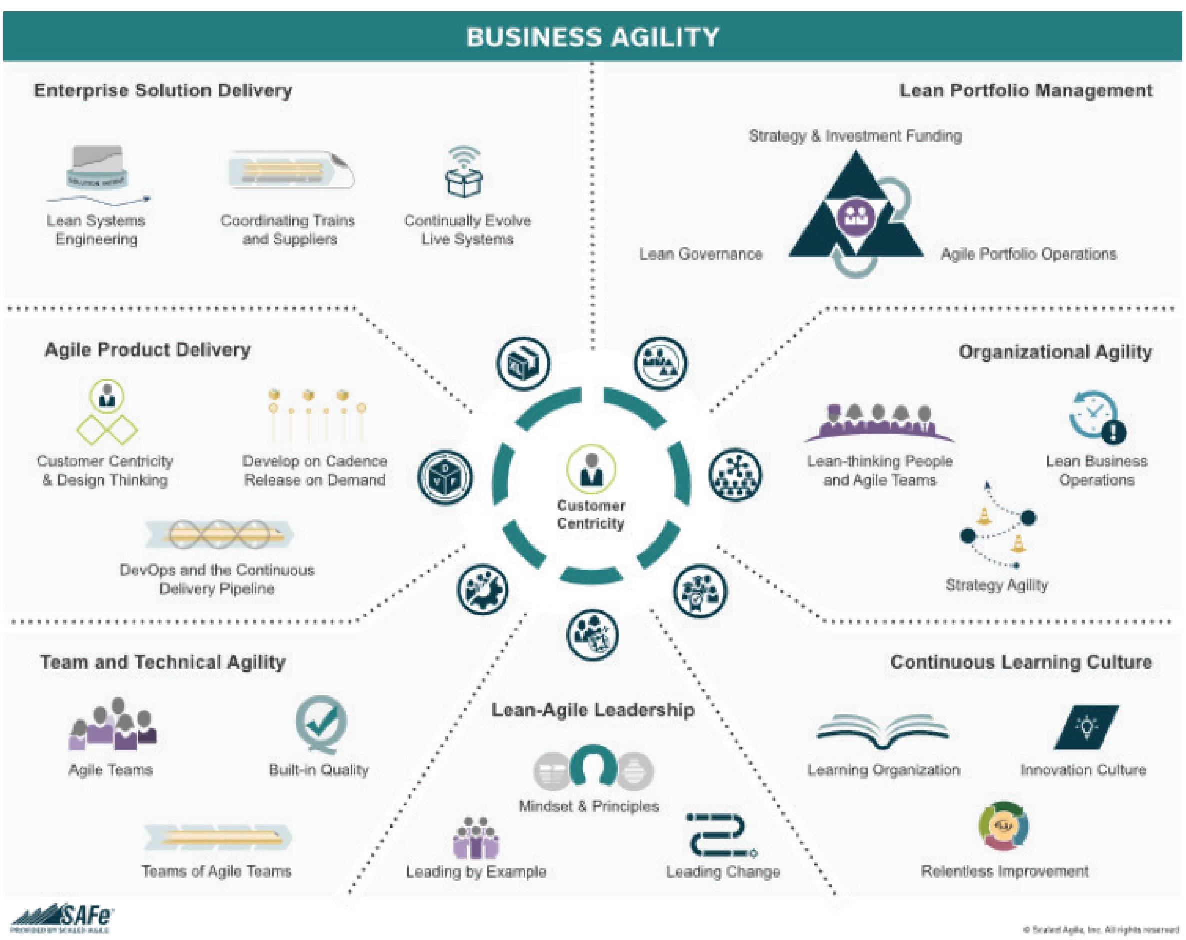
[4] https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2115_National%20Grid%20USA%20Service%20Company%2C%20Inc_v4_RELEASE_508.pdf

of the technology platforms discussed in this Section. SAFe is a widely used industry best practice, which has been successfully adopted across many industries including infrastructure, government, IT, and consumer goods.

The Company operates in an industry driven by regulations, complex infrastructure, and long-standing processes. However, the advent of renewable energy, grid modernization, and the increasing need for customer-centric solutions demands a new agility in the Company's operations. By adopting SAFe, the Company is:

- **Enhancing speed-to-market:** facilitating faster delivery of new products by streamlining processes, eliminating bottlenecks, and enabling cross-functional collaboration. This enables a swift response to market, customer, and business demands and changing customer needs.
- **Improving customer satisfaction:** emphasising customer-centricity and ensuring that new products are aligned with customer expectations. By involving customers early in the development cycle and leveraging feedback loops, solutions can be delivered that better meet customer needs, ultimately enhancing customer satisfaction.
- **Increasing operational efficiency:** promoting Lean-Agile principles and practices, encouraging continuous improvement, waste reduction, and optimized resource utilization. This approach helps to streamline the Company's operations, reduce costs, and improve overall efficiency.

Exhibit 6.7: SAFe Framework



Utilizing a framework that helps align product development efforts with the Company's business goals is significant. It brings together Lean, Agile, and Systems Thinking principles into a comprehensive methodology, which helps to achieve enterprise-wide agility. The key elements of SAFe include:

- **Scalability:** designed to handle large-scale product development efforts, making it an ideal fit for the Company; an organization continuing to mature its product delivery approach. It allows for the coordination and synchronization of multiple teams working on complex projects, ensuring efficient collaboration, and minimizing interdependencies.
- **Cross-functional collaboration:** emphasizes the need for cross-functional teams to work together, breaking down silos and fostering effective communication. As a large multi-national organization, this collaboration spans different departments, such as engineering, operations, customer service, and regulatory affairs, facilitating a holistic approach to product delivery.
- **Portfolio management:** ensures a structured approach to managing the portfolio of products and initiatives. It supports the prioritization of projects, allocation of resources, and ensures alignment with strategic objectives. This enables better decision-making and improved resource allocation to maximize business value.

By implementing SAFe, the Company will realize a wide range of benefits, such as responding quickly to market and customer dynamics and changing regulatory requirements. It has allowed the fostering of an environment where innovation thrives, thus enabling the introduction of new technologies and solutions that address evolving customer needs. The Company has internalized the value of taking an iterative and incremental approach, which promotes faster delivery and greater impact of products. By breaking down work into smaller, manageable increments and leveraging frequent feedback loops with key business and customer stakeholders, the Company has reduced the time it takes to bring new products to market and deliver value to its customers. Importantly, adopting SAFe has ensured quality be accentuated at every stage of the product development lifecycle.

6.3.2 Description of Implementation Justification and Expected Benefits

The following Sections describe each of the technology platforms being deployed in the next 10 years, including an indication of relevant prior regulatory approvals. These technology platforms all fall under the "Platform Technology" investment category for the Section 7 cost and benefits summaries, unless marked otherwise in Exhibit 6.4.

6.3.2.1 Network Management

6.3.2.1.1 Advanced Distribution Management System (ADMS)

This program has been previously approved as part of the Grid Modernization Plan (2022 to 2025).

As part of the second GMP, the Company has made significant progress on its implementation of ADMS and has authorization to complete its deployment of the foundational ADMS program in 2025. The Company is thus not proposing foundational deployment of ADMS as part of this Future Grid Plan. However, the Company includes below a brief description of how it envisions leveraging ADMS as an underlying foundational technology for future network management investments. As discussed below, new incremental features in ADMS will be deployed over time as needed to support future network management investments and use cases.

ADMS is a software platform that enables real-time visibility and control of the physical infrastructure making up the distribution system. The platform works to integrate SCADA, OMS, and DMS functionality into a common database and user interface. As the backbone of the of a modern distribution network management system, ADMS uses advanced algorithms, data analysis and modeling features to optimize the configuration and operation of the electric distribution network and provide a level of real-time visibility that the distribution control center has never had before. In particular, ADMS includes the ability to produce real-time load flow, which will be critical for the Company's distribution control centers to monitor and control a network rich with DERs and ensure a more reliable and stable power supply for customers.

Managing voltage, frequency, and power flows, ADMS is the network management platform that not only operates the grid, but also opens up the opportunity for benefits from advanced capabilities that lowers the cost of energy and enhances load flow through VVO and CVR, improves reliability through Fault Location Isolation and Service Restoration (FLISR), and integrates more renewable energy and DERs through coordination with solutions like DERMS.

6.3.2.1.2 Distributed Energy Resource Management Systems (DERMS)

Investment in DERMS has been previously approved as part of the Grid Modernization Plan (2022 to 2025). The Company proposes to develop and deploy new DERMS features as well as scale its in-flight DERMS investments through the ESMP between 2025 and 2029.

Approved Investments:

Following approval of the GMP, the Company has started to implement its Distributed Energy Resource Management Systems (DERMS) Phase I investments. The Company's DERMS Platform refers to a group of individual software products managed by the Company that operate together to actively track, plan, manage, and operate DERs interconnected to the distribution network through monitoring and control either directly or via an aggregator. DERMS works closely in conjunction with ADMS, which enables much of the underlying intelligence that DERMS uses, to facilitate operational DER management. The DERMS functionality for which the Company has received authorized cost recovery to implement as part of the 2022-2025 GMP, includes the Company's first wave of DERMS capabilities and modules focused on short-term local forecasting, grid edge control, economic dispatch engine, and market platform delivery.

Collectively, these approved investments are primarily intended to reduce the cost and timeline to interconnect to the network by delivering the capabilities required to support a flexible interconnection (i.e., the Company will implement active management of DER curtailment so that DER can connect in a constrained location without posing risks to the network). By reducing the cost and time for new DERs to interconnect to the system, these investments will help support the Commonwealth's DER adoption goals and will enhance customer experience by enabling a faster and lower-cost network access options for customers.

Plan Investments:

As part of the Company's Future Grid Plan, the Company proposes to progress an expanded set of DERMS features and modules (i.e., DERMS Phase II). This second phase of DERMS investments continues to deliver new features that support the Phase I investment objective to accelerate interconnection of DERs, and introduces several new features to deliver a second objective focused on leveraging DERs to provide grid services (i.e., the technology capabilities that need to be in place so that DERs can reliably help the distribution network).

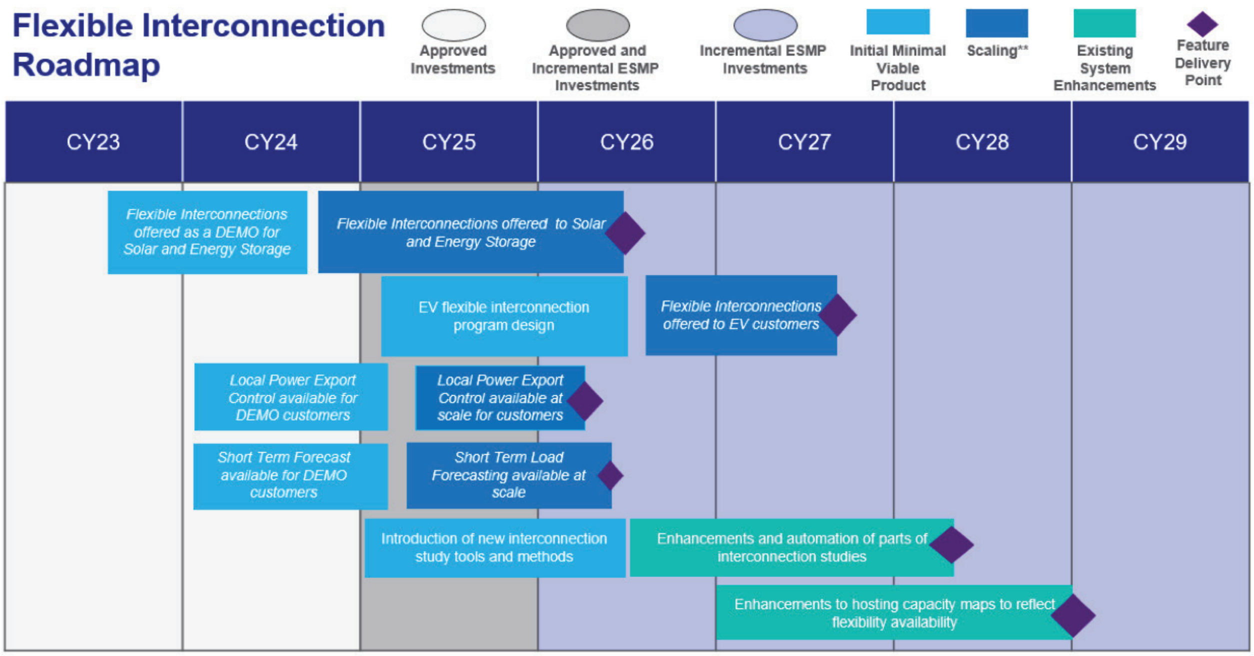
The DERMS Phase II investments will be primarily used to:

1. Scale Flexible Interconnections

- Continue to scale and expand capabilities for flexible connections beyond the initial ARI GMP solar pilot and the Company's subsequent ARI ESS pilot to enable accelerated network access options to reduce interconnection cost and time for solar, ESS, and EVs.
- Improve the interconnection process through enhanced transparency on network hosting capacity and enhanced capabilities to expedite interconnection studies.

Exhibit 6.8 below provides a visual representation of how these capabilities will progress over time and what will be different for the Company's DER customers as we deploy new functionality in DERMS.

Exhibit 6.8: DERMS Phase II Implementation Roadmap



Note: Roadmap is intended to be illustrative. Additional scaling activities and technology improvements and enhancements will continue occur beyond initial feature delivery point.

To deliver these capabilities, the Company will test and scale technology functionality using the scaled agile framework (see Section 6.3.1), including technology functionality to support short-term forecasting, ADMS integration, DER dispatch and control, accelerated DER interconnection studies, and hosting capacity maps.

2. Leverage DER for Grid Services

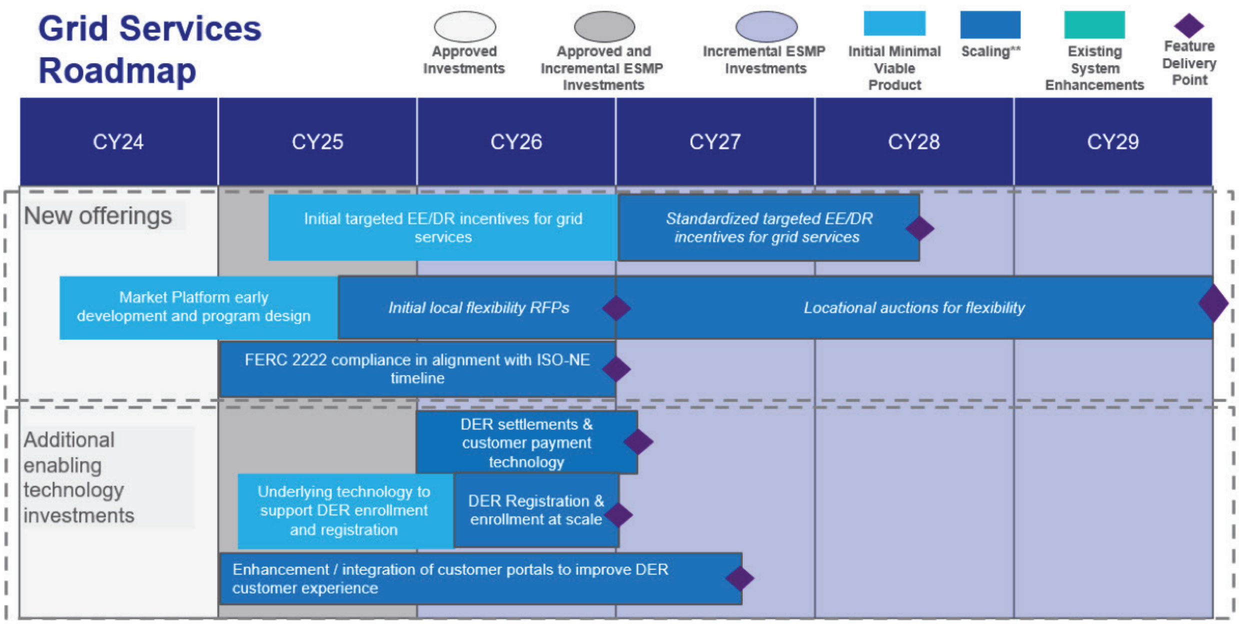
a. Accelerate pathways to procure and manage DERs flexibly on the network to provide grid services that help address distribution system constraints, provide reliability, and defer and/or avoid network investments as NWAs, including via the continued development of a market platform to manage programs for DER to provide services to the distribution network.

b. Help enable customer DERs to participate in the ISO-NE wholesale markets per FERC Order 2222, by deploying new technology to support the registration, review, and operational coordination processes for DER aggregations enrolling in the ISO-NE wholesale markets.

c. Enhance the customer experience and accelerate and enhance DER adoption.

Exhibit 6.9 below provides a visual representation of how these capabilities will progress over time and what will be different for our DER customers as we deploy new functionality in DERMS.

Exhibit 6.9: DERMS Phase II Implementation Roadmap



Note: Roadmap is intended to be illustrative. Additional scaling activities and technology improvements and enhancements will continue occur beyond initial feature delivery point.

To deliver grid services capabilities, the Company will leverage many of the same technology functionalities used to support flexible interconnections (e.g., short-term forecasting, DER dispatch and control), as well as build out additional technology functionality to enable grid services related to DER registration and enrollment, market operations and platforms, and billing and settlement.

These new DERMS features are intended to support future customer programs described in Section 6.11, including expanding flexible connections to EVs, enabling virtual power plants with customer ES, and deploying more targeted usages of customer flexibility to alleviate network constraints. DERMS provides the technology backbone to enable new customer offerings that will create value for our customers.

As noted, the Company has recently been selected to receive an award for its “Future Grid Project” from the US DOE under the IIJA via the GRIP program. The awarded grant will help to partially offset costs to deploy DERMS capabilities such as the implementation of network-adaptive DER connections to support integration of the Company’s ADMS and DERMS functionality, further enhancing the ability to optimize grid assets and DER operations.

6.3.2.1.3 Active Power Restoration Services (APRS)

This is a new proposed investment (with support from IIJA/GRIP Program funding).

Plan Investment:

The awarded IIJA/GRIP Program grant from DOE for the Company’s “Future Grid Project” will support the deployment of new features in ADMS and DERMS to better integrate DERs on the network as part of the Company's outage restoration strategy. The Company refers to these capabilities as "Active Power Restoration Services" (APRS). The awarded grant will be used to help offset costs for this investment.

The Company has been implementing FLISR across its network as part of the GMP. FLISR is a self-healing scheme involving the automatic opening and closing of switching devices on the distribution network to reroute power in the event of an outage on the network. As part of the GMP, the Company has approval to integrate its FLISR scheme into ADMS, which will provide advanced control of the switching devices, determine how much load can be safely rerouted and transferred from one part of the network to another, and lay the groundwork for future opportunities to improve the intelligence, speed, and coverage of the Company's outage restoration efforts.

In this Plan the Company proposes to improve the FLISR scheme beyond the currently scoped foundational use cases by enhancing current FLISR control scheme capabilities to include situational awareness of customer connections by enhancing the integration with ADMS and DERMS, and adding integration with AMI. As the Company continues to accelerate deployment of DERs on the network, the high penetration of DERs on the distribution grid will present challenges as well as opportunities for the existing FLISR scheme that APRS would address. In particular, as the Company scales and evolves its centralized ADMS-based FLISR system, there is opportunity to partner with DERMS to dispatch DERs as part of outage restoration along with switching devices, which would increase the load transfer capacity of the FLISR scheme and restore power to a larger number of customers.

6.3.2.1.4 Future of Network Management Demonstration Projects

This is a new proposed investment (with support from IIJA/GRIP Program funding).

Plan Investments:

The awarded IIJA grant for the Company's "Future Grid Project" will help support building new network management capabilities related to substation-edge computing.

The substation-edge computing project aims to validate the Company's ability to digitize assets and leverage that digitization to facilitate more dynamic (e.g., autonomous) data-driven management of the network. The overarching purpose is to identify transformational ways to harness the potential of cloud technology and virtual assets on the network to improve the reliability of network operations and reduce the physical infrastructure footprint and associated costs for future ESMPs. That is, the Company will build new capabilities and test the bounds and feasibility of using software-induced network management to cost-effectively support traditional use cases on the network that would otherwise require expensive physical infrastructure. When testing these capabilities, the Company will use a "test" and "scale" approach to uncover the necessary underlying technology and data architecture that would need to be deployed, as well as to lay the groundwork to scale these capabilities to meet some of the anticipated distribution network management challenges and opportunities associated with high volumes of DER and electrification in the future.

The substation-edge computing project will focus on two main components:

- **Digitize the network and leverage software-defined assets to reduce the physical footprint of the network**. The Company will explore using dynamic management of digitized assets to meet different grid use cases (e.g., load management versus protection relays) – which vary in terms of latency and other requirements – and the accompanying technology infrastructure required to deliver on those use cases.

- **Push data computation and infrastructure to the grid edge**. As more assets are digitized on the network and more data is collected from devices located on the grid edge, data needs will continue to grow. The Company anticipates that there will be an inflection point where certain data management and analytics functions will be more fit for purpose to occur at the grid edge, rather than via centralized systems.

6.3.2.1.5 Conservation Voltage Reduction (CVR) and Volt/Volt-Amps Reactive Optimization (VVO)

Investment in this system has been previously approved as part of the Grid Modernization Plan (2022 to 2025). The Company proposes to scale this investment through the Plan between 2026 and 2029.

Approved Investment:

Through the GMP, the Company received authorized cost recovery to deploy CVR/VVO through 2025 to a group of high value feeders.

CVR and VVO are initiatives that use advanced technology to smartly control voltage regulation devices. The primary objective is to optimize the Company's power distribution, resulting in more efficient energy usage and minimized system losses. This not only leads to reduced demand and energy consumption for customers, but also offers financial savings due to reduced operational costs.

VVO technology flattens the voltage profile of a feeder by applying intelligent control to capacitors and regulators on the feeder which serves to minimize electrical losses, which allows the Company to lower the source voltage at the substation to provide energy savings for both the utility and the customer. Customer benefits are realized through reduced costs for electric energy and system capacity, which result in lower customer energy bills and lower emissions.

In line with industry best practices, the Company is also looking forward to integrating VVO/CVR with the ADMS.

Plan Investments:

As part of this Future Grid Plan, the Company proposes to extend its deployment of CVR/VVO in coordination with other network investments beyond 2025 to select circuits across the service territory in order to derive high value and systemic benefit. CVR/VVO expansion will support multiple benefits:

- Energy Conservation: With CVR, the Company aims to reduce the voltage slightly without compromising service quality. This strategy will lead to decreased energy consumption.
- Support for Renewable Energy: As more renewable resources like solar and wind energy are integrated into the network, ensuring steady voltage levels becomes pivotal. VVO/CVR will play a crucial role in managing the intermittent nature of these resources.
- Enhanced Equipment Longevity: VVO/CVR ensures that Company devices operate at optimal levels, thereby potentially prolonging their life and avoiding premature replacements.

- Superior Power Quality: VVO's role in reactive power control ensures that Company customers always receive power within the desired voltage range.
- Boosted Grid Visibility: Incorporating VVO/CVR into ADMS improves Company oversight of the grid's health, allowing us to address concerns promptly.
- Improved Load Controllability: The integration of VVO/CVR into ADMS improves the Company's ability to optimize and control load flow.

6.3.2.1.6 Early Fault Detection (EFD)

This is a new proposed investment.

Early Fault Detection (EFD) is a technology that improves safety and reliability on the network by detecting and locating defects in electrical infrastructure before they develop into electrical faults that cause fires, equipment damage, and electrical supply interruptions. The defects that EFD detects include incipient asset failure due to degradation, damage, and asset compromise by external factors such as vegetation. Utilities use EFD Systems to monitor both AC and DC utility distribution and transmission power line networks and substations, electrical infrastructure in large industrial sites, and electrical rail networks.

EFD is a passive listening, non-contact, multi-location, radio frequency, continuous electrical network surveillance system composed of hardware (sensors) and software. Electrical equipment embedded in live electric infrastructure experience electrical and magnetic fields. If equipment becomes defective due to degradation, damage, or any other factor, these field stresses can cause it to emit abnormal radio frequency (RF) signals. Healthy electrical assets operating well within "normal" voltage ratings are "silent" at select radio frequencies. EFD works by detecting abnormal RF signals that are emitted from electrical equipment that indicate deterioration, damage, or compromise that increase the risk of equipment failure. EFD scans the infrastructure once every second to detect sudden rapid occurrence of defects as well as long-term deterioration of electrical assets.

EFD sensors are non-contact: they do not connect to primary conductors on the primary infrastructure; they are either capacitive-coupled radio frequency (RF) sensors, or high frequency current transformers (HFCTs) on the screen ground connections of HV cables. These sensors act as passive "listeners," and they do not generate, radiate, or inject any signal. They simply collect whatever RF signal that is present at the sensor path. An EFD system spreads across locations: it uses multiple RF data collection units to collect data on radio frequency signals that arise from the monitored electrical infrastructure. The EFD System, is "voltage agnostic" and can be deployed and operate on all voltage levels.

The Company recently completed a two-year demonstration project (completed in December 2023) evaluating the effects of EFD for an initial small-scale deployment in the North Shore, and concluded that deployment of such technology can contribute to the following benefits:

- Improved Safety: EFD can prevent equipment failures that result in electrical hazards, such as fires or electrical faults, improving the safety of the local community and line workers.
- Enhanced Equipment Longevity: EFD enhances the information available on asset life which can enable the transition from time-based maintenance to condition-based maintenance. Equipment can extend its life beyond traditional time of replacement if its condition is determined to be acceptable with EFD.

- Decreased Risk of Equipment Failure: EFD can prevent the costly "emergency" replacement process for unplanned sudden equipment failures.
- Boosted Grid Visibility: EFD collects data on asset health, boosting the oversight of the grid's health, enabling improved decision making and network operations.
- Improved Grid Reliability: EFD reduces the risk of equipment failures, and consequently, power outages, which in turn reduces customer minutes interrupted and helps maintain consistent power delivery for customers.
- Increased Asset Replacement Efficiency: EFD enables proactive equipment replacement which can set up a more strategic and systematic asset replacement strategy that leads to workflow efficiencies and subsequent cost savings that can be passed down to the customer.

As part of this Future Grid Plan, the Company proposes to expand deployment of EFD onto a blended mix of identified higher risk circuits (as determined by distribution planning engineering), as well as circuits that service identified EJC communities within the Company's service area.

6.3.2.2 Communications

A portion of these investments have been previously approved as part of the GMP (2022 to 2025). The Company proposes to scale its communications investments and introduce new features through this Plan between 2025 and 2029.

Approved Investments:

As approved in the GMP, the Company has initiated efforts to build and operate a private communication network, which will provide the majority of communications for the grid modernization investments and new distribution devices, including those supporting customer DERs. Transitioning from public to private network communications will result in greater network control and reliability, reduced long-term costs (e.g., avoid commercial cellular RTB costs that increase with every new grid device added), and better position the Company to accommodate the anticipated exponential growth in the number of endpoint nodes that need connectivity due to the increasing adoption of DER.

Plan Investments:

To support the Company's Future Grid Plan and the Commonwealth's Net Zero goal, foundational data network technologies must be developed and solutions implemented. These components will provide a securable, maintainable, and scalable solution that can be built upon to deliver the desired outcomes supporting reliability, affordability, and sustainability for the Company's customers.

Data communications network investments are a fundamental part of developing many of the advanced capabilities the Company's Future Grid Plan outlines, including ADMS, DERMS, and AMI. The investments described in this section include Operational Technology (OT), Information Technology (IT), and Common Network components. Together, these components comprise a holistic data communications capability that is fundamental to the Company's Future Grid Plan.

A significant portion of the operational telecommunications network costs are the costs to build and operate a private network, which will provide the majority of communications for the grid modernization investments and new distribution devices, including those supporting customer DERs. Aside from the added benefits of greater network control and reliability in transitioning from a public carrier solution to a private one, a key driver of this change is to reduce long-term costs (e.g., commercial cellular RTB costs) that increase with every new grid device added. Given all the grid modernization initiatives, plus increasing adoption of DG and future EV adoption, the Company anticipates exponential growth in the number of endpoint nodes that will need connectivity. The large increase in connected devices anticipated in the future would result in significant commercial cellular RTB costs if investments are not made in a communications network strategy.

As part of this Future Grid Plan the Company proposes to continue the delivery of the communications network investments that have been initiated through the GMP beyond 2025, as well as to deploy new incremental investments to support the future needs. Delivery of the private communications network will result in a more reliable, secure, and cost-effective communications network that can more adequately support a more intelligent and DER-rich network operation for Company customers. The proposed expanded investment builds on similar activities described in the GMP, including:

- **Private-fiber network (scale from GMP)** - One of the biggest drivers of upgrading the telecom network with new network gear and fiber connectivity is the commercial carriers' imminent plan of eliminating Digital Signal 0 (DS0)25 and analog leased lines to substations and replacing them with Transmission System 1 (T1)26 or other digital technologies that may not be the most future-proof or appropriate for the proposed grid modernization initiatives. By proactively responding to this unavoidable directive brought on by the carriers, the Company will take the lead in network redesign and leverage on-going efforts, wherever possible, to cost effectively expand the reach of fiber optics. In order to enable the GMP initiatives underway, the existing rudimentary analog communications must first be upgraded to current technologies that support the new requirements for increased network performance, security, reliability, and control.

- **Field area network (FAN) (scale from GMP)** – To enhance reliability of the grid, the Company plans to enable control of consumer DER and granular distribution control through ADMS (FLISR, Cap Banks, VVO, Reclosers, DSCADA, etc.) to route energy where it is needed and enhance reliability. Consumer DER will also be allowed to participate in the energy market to pass savings and efficiencies to customers. Additional control over consumer devices will be needed to manage electric flow and monitor voltages, further enhancing reliability and controlling costs. These solutions all require a tight coupling of National Grid systems and consumer systems and a reliable and robust network solution. The primary access of the FAN is wireless using a combination of commercial cellular and privately licensed spectrum, which offers the highest level of control, reliability, and security. The FAN supports the Company's plans to integrate remote sensors, advanced capacitor controls, line voltage regulators, state-of-the-art reclosers and circuit breakers, as well as connected DER devices with the distribution control center ADMS. Existing radio sites such as microwave or land mobile radio (LMR) will be leveraged to reduce cost and establish the anchor design. Site acquisition companies responsible for leasing, zoning, and permitting will assist in identifying other commercial radio sites or new towers located at select substations. Commercial construction companies specializing in radio network builds will perform the deployment work outside of installations in and around power lines. The FAN will provide near ubiquitous FAN coverage throughout the Company's Massachusetts service territory allowing for an expansion of the network into the field (or "edge"), which will enable multiple grid modernization efforts through a communications path to the Company's back-office systems. Fiber deployment will also be leveraged for back-hauling FAN communications.

- **Operational Telecommunications Security** - Additional deployments of field solutions, including Fault Location, Isolation, and Service Restoration (FLISR) and Volt VAR Optimization (VVO) devices, DER, Substations, and other sensor devices introduce additional threat vectors to the grid. To secure these assets and ultimately deliver value to the Company's customers, the entire data communications network will require on-going cyber security solutions. Threats to network control must be mitigated, and service recovery solutions must be put in place in case a breach occurs. A Central Security Management solution and competency for OT systems will be established to secure and scale the solutions in support of Future Grid plans. Some locations will be centrally deployed and managed and others, while being centrally managed, will require solutions on site. This set of common services will be provided consistently across OT technologies. Bolstered cyber security standards to address vulnerabilities across OT systems will be implemented. In addition, existing OT sites, systems, and devices will be retrofitted to the updated standard and deployed to all new solutions.

- **Operational Telecommunications Data Centers** - As OT and other connected field systems such as FLISR, VVO, DER, ADMS, and SCADA devices grow to support electrification and reliability, they will need to be managed and secured in a centralized manner. Centralized management is cost-effective for customers but allows for economies of scale. NERC Federal mandates that have difficult and costly control requirements can also be centrally managed. An OT Data Center will be established to connect common OT services with IT Data Centers. It will serve as a centralized management space that is under a single set of NERC/CIP controls. Redundant OT Data Centers and common services will be designed and deployed to allow distributed implementations across existing IT data centers, operating centers, and the cloud. OT common services will be centrally deployed and managed by existing IT data centers, failover when communications are lost to the IT data centers will occur in operating centers, and OT cloud services will be integrated into the new architecture. The architecture will also accommodate NERC/CIP, OT resiliency, and time-sensitive requirements..

- **Connectivity for Operational Telecommunications Administration** - Customers looking to participate in demand management programs need ways for their home systems to communicate to the utility. Consumer and commercial DER wishing to participate in the energy market need connectivity to the Independent System Operator (ISO) for management. All of these require connectivity to third-party vendors that can be centrally supported. A centralized Third-Party Connectivity will be established through the OT Data Center for all use cases that need remote connectivity between an OT solution and an external solution. Physical connections will be managed centrally as part of the OT Data Center and access control will be supported through central security services. Data for warranty services or other processing solutions will also be provided and all data will be classified and validated before being sent off site. A new network architecture will be implemented to provide tightly controlled administrative access to OT systems. Existing OT sites, systems, and devices will be retrofitted to the new standard and all new solutions will adhere to this standard.

- **Enterprise Network Edge Protection** - Security and operational efficiencies are key to maintaining service without driving up costs for our customers. Consolidating into fewer data centers supports security and cost efficiencies and supports the reliability of the electric network. One Data Center, expanded at two sites for redundancy, will deliver services supporting consolidation and security. Security services will provide common platforms and be centrally managed and monitored. The Data Center will provide both physical security and aggregation of services for virtual security. In addition, common platforms can be centrally managed and monitored and availability and redundancy can be managed. A DMZ will need to be created to replace the legacy security edge solution supporting publicly-facing Internet solutions. Physical servers and storage will also be consolidated, which will improve the cost structure and simplify the infrastructure management. Common network and security services will be defined, managed, and maintained out of the Data Centers and management and delivery will be standardized. A new DMZ will be established at each site.

- **Software-Defined Wide-Area Networking** - Managing dedicated point-to-point solutions for network connectivity is costly and inefficient. Many organizations now take advantage of generic network connectivity services utilizing a Software-Defined Wide-Area Network (SD-WAN) solution to aggregate and control a variety of connections in a centralized location, which has lower cost connectivity options and leads to cost efficiencies. The Company will migrate away from legacy MPLS point-to-point and leased lines in support of a SD-WAN across all corporate sites, in support of SDWAN which provides an additional transport lane using public IP instead of private IP for the routing of cloud-based applications, in conjunction with the already existing private IP transport lanes. Whereby reducing full reliance on private IP (MPLS) connectivity while maintaining control and security of the network. SD-WAN solutions will be deployed at remote locations to allow for this control with centralized management. SD-WANs will be implemented as the standard for all Data Center and Corporate sites and will be implemented for all new deployments and legacy system refreshes based on asset lifecycle. Sites will be migrated from leased, and legacy point-to-point lines to lower cost internet access solutions.

- **Corporate Data Networks** - Cost effective solutions for software-based voice networks and enhanced worker mobility will support efficiencies for the growing workforce, which will in turn support customers by maintaining operational expenses as the workforce grows and becomes more mobile. The standard connectivity model will be modernized from a wired to a wireless connectivity standard, allowing workers to remain productive no matter where they are in support of grid modernization efforts. Combining mobility with a software-based phone solution allows even more productivity without physical location limitations. Software-based and wireless phone systems also require less physical equipment and maintenance, further reducing cost. Securing devices on the network, including devices owned by employees such as phones, will support worker productivity. This will also require additional security solutions. All locations will be migrated to utilize wireless connectivity with optimal coverage and bandwidth capacity for the location. Users will be migrated to Microsoft Teams for video and data collaboration.

- **Dedicated Voice Networks** - Dedicated voice networks are costly to maintain and are provisioned to single locations. While useful for safety reasons or in call centers, they are not needed for the average knowledge worker. All standard knowledge workers will be migrated to software-based voice solutions. Dedicated voice lines will be maintained where necessary for safety purposes or by exception.

- **Configuration and Change Management** - A properly maintained data communications network is well defined, and the effects of changes on network elements and the associated business services and applications are well known. When systems are not in the proper configuration or changes to assets are not well connected to the services they are providing, unwanted outcomes can occur that can affect service delivery and, therefore, our customers. Proper configuration and change management foster a clear understanding of the current state and upcoming changes, enhancing reliability for our customers. To accomplish this, updates and expansion of solutions will be necessary to manage the current configuration and support change over time. This will include automated configuration updates of assets deployed to support the network and associated details such as geographic location, contracts, asset lifecycle, and supported services. Standard processes and one standard toolset will be implemented to manage asset configuration and change across National Grid for all network technologies. Systems that house configuration data will be integrated with the standard toolset to ensure continued accuracy.

- **Asset Management** - To increase reliability for customers and enable new solutions, technologies must have a clear asset lifecycle with associated maintenance, decommissioning, and depreciation cycles. When asset lifecycles are clearly defined, the asset has a more productive lifespan. In addition, plans can be made to upgrade technology as it becomes obsolete. Technology solutions have a relative lifespan that must be appropriately managed. Asset management strategies, including depreciation and replacement lifecycles, need to align with expected asset lifecycles. An accurate inventory of all data network assets will be developed across the Company. Asset lifecycles, replacement standards, and replacement plans will be developed and assets that are beyond their life expectancy will be replaced.

- **Automation and Orchestration** - As new solutions are implemented to support reliability, electrification, and decarbonization, the ability to scale operations becomes an important factor in maintaining costs. Automation and orchestration enable systems to design repeatable processes, reducing human-induced error and costs associated with full-time employees. Automation and orchestration solutions are an ideal investment options for solutions that will be scaled and solutions that are used for troubleshooting or provisioning. Not only does automation and orchestration reduce operational expenses, but it results in a more consistent approach and is less error-prone than manual activities. The Company will invest in these solutions, which includes mapping processes that will be replaced, tooling them with automation, and managing the automation tools.

- **Physical Security and Cameras** - The grid must be protected from a cyber and physical standpoint to support customer reliability and the safety of National Grid employees. Substations and other equipment must be physically surveilled to deter tampering and enforce justice when tampering does occur. Cameras provide real-time views of the physical equipment for security and safety monitoring but require substantial network bandwidth. To support video feed, networks with the required bandwidth must be provisioned and should be segregated from other traffic. The fiber backbone will be utilized as a transport with software-defined networks supporting the ability to isolate video feeds with the appropriate bandwidth provisioned. These networks will leverage OT Data Center services and be deployed in a standardized fashion.

- **OT/IT Lab** - National Grid must test solutions and try out capabilities in a lab environment before they are implemented. Proper lab deployments reduce costs due to rework and unplanned issues, which benefit the overall reliability and efficiency provided to customers. A lab environment is used to test solutions currently in production for upgrades and to test proofs of concept. Standardized processes and procedures allow groups to utilize labs in a planned and prioritized manner and support the publishing of results to stakeholders and other interested parties. Appropriate physical assets, which could include one or more locations, are needed to support OT and IT testing. Lab policies and procedures must be developed to standardize how lab time is scheduled and how tests are performed. Test plans and success criteria should be documented before lab access is granted and all results should be freely published for review by stakeholders and peers. An OT/IT lab will be provisioned to test the application and integration of OT and IT networks in support of a technology-enabled grid. Formal processes will be developed, and resources will be deployed to support testing activities.

6.3.2.3 Metering and Billing Systems

6.3.2.3.1 Advanced Metering Infrastructure (AMI)

The investments described in this Section were approved via the Company's AMI filing and are described to present a holistic view of the Company's investments.

The Company has already received authorization and funding for full deployment of AMI and is not proposing additional AMI investments through the Future Grid Plan.

The Company has begun to invest in some of the keystone systems that will enable the next generation of metering technologies, including standing up communication networks, data processors, and management systems. Testing the technology and processes associated with generating value from AMI has also already begun.

Upon receiving approval in November 2022, the Company has been participating in a series of meetings with an AMI Stakeholder Working Group (AMI SWG). As part of the DPU Order, the MA EDCs have convened 9 times since February 1, 2023, and per DPU direction, have hosted sessions with the AMI SWG on four topics: (1) customer and third-party access to customer usage data; (2) customer education and engagement; (3) billing of TVR offered by competitive suppliers; and (4) AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products.

On December 13, 2023, the AMI SWG completed the last of its deep-dive discussions on "customer and third-party access to customer usage data." The AMI SWG has discussed in detail the parameters, tradeoffs, and requirements surrounding AMI data transfer, protocols for access by customers and third parties, and how data can be leveraged for new uses cases. A summary of these discussions will be captured and reported in the AMI SWG's next quarterly status update report to the MA DPU on February 15, 2024. A full summary of the AMI SWG's areas of consensus and areas of disagreement across the four topics noted above is to be reported in a final status report on August 1, 2024. Additionally, the Company, along with the other MA EDCs and the DOER, are in discussions with New Hampshire and other neighboring states on a regional standard Energy Data Platform/Hub. This effort, led by the NH Data Governance Council, is actively seeking to procure federal funding per the DOE's GRIP program as part of the IIJA. The Company expects to have further information in this space in the first half of 2024.

When complete, customers will experience a wide variety of new functionalities, including a sampling of capabilities outlined in Exhibit 6.10 below. Note that this is not all of the customer-focused benefits that will be enabled by AMI.

Exhibit 6.10: New Customer Functionalities Enabled by AMI

Functionality	Brief Description
Near Real Time Customer Data Access	▸ Customers will be able to view accurate, granular, and timely data associated with their usage through the online customer portal.
Customer Energy Insights	▸ The Company will provide customers with insights into their energy use trends that they can use to lower their bills and environmental impact.
Green Button Connect	▸ Customers will be able to provide third party vendors with access to their meter data to provide tailored insights and services informed by data.
Outage Detection	▸ AMI meters will automatically send outage information to the control room to eliminate the need for customer outage reporting and reduce the time for service restoration.
Remote Electric Connect and Disconnect	▸ The Company will be able to connect or disconnect new customers during the move-in and move-out process without the delay of sending a truck. This will enable day-of service restoration for and reduce delays associated with account or service changes.
Power Quality Monitoring	▸ The Company will be able to monitor power quality, such as voltage, to ensure that the power delivered to customers is within the standards set by regulators and offer new tools to correct those issues when they arise resulting in higher customer satisfaction.

In the future, AMI will provide customers with enhanced understanding, choice, and control over their energy usage, enabling possible reductions in their total bill. The Company will leverage user friendly interfaces and messaging to provide customers with granular data about their energy use, along with strategic insights into what is driving their consumption so they can take action. To make proactive management of their energy use and bills more attainable, AMI will also make it easy for customers to provide that data to third party contractors if they choose to do so. Third party contractors may include qualified energy experts in the fields of EE, DR, solar PV, and ESS who can design solutions, informed by data, that can reduce customers' energy consumption, bills, and environmental impact.

AMI meters also enable new capabilities in demand side management through passive and active methods like TVR and DR respectively. In the case of TVR, improved pricing signals, such as higher rates during times of high wholesale energy prices and distribution network load will encourage customers to shift their energy uses to off-peak times – lowering the total cost of service to all customers. AMI also enables new DR programs where the utility can sign customers up to participate in manual or automated programs to shift electricity-intensive processes to off-peak times. For example, utilities across the country have been leveraging electric water heaters – which are extremely efficient in storing off-peak heated water for on-peak use – with minimal customer impact or inconvenience.

In addition to the direct customer benefits provided by AMI, the meters, network, and data flowing from these systems will support additional capabilities, including outage detection, VVO, and CVR which will be implemented by ADMS, but are enabled by grid-edge sensors in the AMI system.

6.3.2.3.2 Time-Varying Rates Billing Engine

This is a new proposed investment.

A robust and flexible billing system is fundamental to achieving the clean energy transition. Utilities need to be able to implement and operate a set of new rates and pricing mechanisms to provide economic signals that align grid needs with customer flexibility (e.g., time-of-use rates, demand rates).

The Company's current billing systems have little ability to bill customers at rates that reflect both demand and energy usage or time-of-use. TVR are limited today primarily to large C&I customers. The Company's current billing system is not built to efficiently implement TVR at the scale required for residential customers in coming years to realize the benefits of new AMI-enabled rates. The Company has determined that a more flexible and modern rate engine external solution will provide the necessary capabilities to support an evolving billing and rates environment. This modular solution will be integrated with the Company's centralized customer information and billing platform (the "CSS system"), which will enable the company to offer new rates to customers that take advantage of AMI in a shorter time and with lower implementation risk. This approach has been successfully adopted by other utilities in the US.

As discussed in more detail in Section 6.11, the ability to bill customers efficiently for TVR is a critical enabler for delivering more accurately aligned bills based on cost causation and empowering customers with more control over their monthly bill. TVR will also be a critical component for managing load on the network and is a critical prong in the Company's strategy to better integrate flexible demand to reduce system peak. Relatedly, TVR may create additional economic incentives for customers to adopt flexible demand devices in their homes and businesses like controllable thermostats and behind the meter (BTM) ES.

As part of this Future Grid Plan, the Company proposes to develop and deploy new billing system technologies that can support accurate billing and settlement for customers participating in future TVR and pricing structures.

6.3.2.3.3 Markets Settlement Engine

This is a new proposed investment.

In addition to time varying rates, the Company intends to implement new incentive programs to activate and compensate customers for using their flexible DER to provide grid services. Please refer to Section 6.11 for a more complete discussion of the proposed grid services market programs and products that the Company intends to test and scale over this ESMP term. In brief, however, the Company intends to create opportunities for flexibility service providers (including individual customers or third-party aggregators) to earn compensation based on their ability to help the Company manage load flow on our network based on targeted (i.e., local) grid needs.

Of critical importance, the Company will need new capabilities to accurately track and measure the performance of these flexibility service providers and issue timely and accurate settlements based on that performance. Thus, as part of this Future Grid Plan, the Company proposes to develop and deploy an appropriate markets settlement engine to facilitate settlements for the future market programs and products proposed in Section 6.11.

6.3.2.4 Customer portals

6.3.2.4.1 ConnectNow: E2E Load Connection Management Portal & DER Customer Experience Enhancements

These are new proposed investments.

The Company's Future Grid Plan proposes technology investments to improve the DER interconnection and electric connection processes, including improvements to the existing customer portal for DER interconnections. To accelerate the adoption of clean energy devices on the network (e.g., solar, ESS, EVs, EHPs), the Company continuously looks for ways to reduce the manual steps and time required for submission, review, and approval of DER interconnections and beneficial electrification connections.

Ultimately, the Company seeks to enhance and merge together the front-end user interface of the existing, separate portals for "Electric Connections" (https://gridforce.my.site.com/electric/s/) and "Distributed Generation" (https://ngus.force.com/s/homepage) under a single, unified brand and user experience (i.e. "ConnectNow"). This will require a multi-pronged approach to address the different maturity levels of the front-end user interfaces and back-end IT interfaces, as well as alignment (where appropriate) of the corresponding business processes. ConnectNow will be distinct from the Clean Energy Portal (see next Section) in that the ConnectNow portal will be the central location for trade partners (e.g., electricians and installers) to submit and actively manage (alongside Company resources) connection requests regardless of technology type. The Clean Energy Portal enables trade partners to submit and manage incentive program applications, which may or may not require any construction by the Company. Where appropriate, the Company will seek to implement a seamless user experience for the subset of approved incentive program applications that drive the need for a related connection request (or vice versa).

Facilitating DER Connections:

- Project management software integrated into the application portal to streamline design and construction portion of interconnection process.
- Enhance End-to-End load connection experience (including EVs, electric heat pumps) comparable to DG applications.
- Preapplication “Research Assistant” Portal (including Hosting Capacity Map expansion and integration with application portal) for all DER requests.
- Advanced Automation of Residential Application Review and Approval.

Advancing End-to-End Load Connection Management Beyond MVP Deployment

In 2018/2019, the Company launched a minimum viable product (MVP) version of its Electric Connections portal. Enhancements to this MVP will enable functionality for load applications comparable to the functionality available for DG applicants and employees:

- Trade partners to submit all relevant electric diagrams for load connection requests.
- National Grid planning engineers & designers to review and provide feedback to applicants.
- Milestone and hold “chess clock” functionality with automated remainder emails.
- Holistic feeder queue management (i.e. back-end database view of DER and load applications on the same feeder and substation transformer).

Enhancing this MVP helps solve the inter-related challenges of customer and system readiness to speed up load connections by upgrading the existing electric connections portal and serving as a repository for load information. The volume of new load connection requests (including heat electrification) is expected to rapidly increase, and for vehicle-2-grid applications (i.e., EV chargers that provide grid services) the distinction between DER and load applications continues to blur. Both of these aspects require a more efficient and integrated connection process. Trade partners (e.g., electricians and EV installers) will be able to use the portal to incorporate grid side impacts into site identification, and planners will be able to proactively incorporate pre-application input into their planning. The Company will also identify and implement business process efficiency and customer satisfaction opportunities with this enhancement project in alignment with the overall effort to replace the legacy STORMS asset & work management system.

DER Pre-Application Research Assistant & Application Automation

The DER preapplication process is a key focus for enhancing the customer experience for interconnection, and its improvement can help to avoid issues, delays, and inefficiencies in the project development process. Therefore, the Company will stand up a preapplication customer interface that will enable customers to work with their contractors to design their technology solution in the optimal way and take action to avoid system designs that will hold up their application or add additional costs in resubmission. It will be a guided questionnaire which will help customers, installers, and developers to research their proposed location and receive location-specific information in real-time. In addition, this enhanced preapplication process will also be offered to electric connect requests, to ensure a unified and seamless connection process for all electric and interconnection requests.

The Company will add a connection schedule feature which will help provide visibility into the construction schedule on a granular level. The customer and the Company can share tasks, milestones, and discuss risks. By automating the residential DG interconnection application review and process, the Company expects that 90-95% of residential customers will receive same-day approval of their application to commence construction. By relying on machine learning, process automation, and other advanced review capabilities, the Company will significantly improve the efficiency of and customer satisfaction with the interconnection process.

Furthermore, the Company anticipates more prospective and existing customers will apply for new services, which will increase the need for a newly improved preapplication process. In an effort to provide customers with insight into the Company's readily available capacity, the Company has made public a System Data Portal (SDP).[3] The site displays hosting capacity maps and heat maps, along with other distribution data such as the Company's Distribution Planning Criteria and Annual Reliability Reports. Hosting capacity is an estimate of the amount of DERs that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. Heat maps are intended to help DER developers identify distribution circuits that are loaded to 80% or more of their summer normal feeder rating. The heat map is also intended to identify where additional capacity exists and can accommodate beneficial electrification, EVs and EHPs. These tools will be incorporated into the pre-application tool to make the connection and interconnection process as efficient as possible.

6.3.2.4.2 Clean Energy 2.0 Platform

This is a new proposed investment.

The Company's Future Grid Plan includes a proposal to develop the Clean Energy 2.0 (CE 2.0) platform. This is a new proposed technology platform to support the Company's implementation and delivery of various clean energy programs, including those related to energy efficiency, electric heat pumps, electric vehicles, and DR.

For the Company to continue delivering customer-facing incentives and programs to customers who elect to take part in the clean energy transition, a new technology platform is required to provide modern and sustainable capabilities for promotion, sales, fulfillment, delivery, and reporting of clean energy products. The Company's current platform for demand-side management products, InDemand, an internally developed system that was designed and implemented beginning in 2003, is based on custom code and technology platforms that are approaching end-of-life and end-of-support. InDemand is composed of fragmented architecture that lacks data uniformity, is labor-intensive to operate and maintain, difficult to resource, provides a poor experience for employees, customers, and trade partners, and is costly. Further upgrades to the aged underlying technology supporting the InDemand platform would not be feasible without a complete re-development effort.

Moreover, the platform in its current form only accommodates EE and EHP programs, but not EV or DR programs. To continue to deliver programs to customers at a pace and scale that will enable the Company to meet the Commonwealth's clean energy goals, a new system will be required.

For the reasons stated above, the Company's Future Grid Plan proposes to develop the CE 2.0 platform. The new technology platform will provide modern technology capabilities for promotion, sales, fulfillment, delivery and reporting of clean energy products and programs to customers in the Commonwealth. This software-as-a-service platform is best-in-class among utilities and comes preconfigured with the Company's most essential requirements. To accommodate fast evolving clean energy objectives and incentives, the system will have flexibility, self-service capabilities, and widely understood maintenance protocols.

Among other benefits, CE 2.0 will:

- Improve the implementation, tracking, and reporting of program achievement.
- Reduce application and incentive payment cycle time, thereby enabling faster processing of incentives and rebates to customers.
- Improve the customer experience for the Company's clean energy products and increase customer adoption.
- Provide a transparent and seamless experience for trade partners.
- Improve collaboration, transparency, governance, and productivity for the Company's clean energy employees, enabling them to focus on value-added work.
- Reduce opportunities for fraud by avoiding manual data management intervention and increasing built-in governance and validations.
- Increase program speed-to-market.
- Increase operational efficiency by decreasing the use of paper documentation, reducing project delivery costs, and accommodating fast-evolving clean energy objectives and incentives.

6.3.2.5 Data

Investments for Foundational Data Capabilities have been approved in previous rate filings. The Company proposes to enhance these programs through the Plan between 2025 and 2029.

Data is in many ways the underlying "blood" that enables all of the transformational technology investments that are required to operate and plan a more dynamic, reliable, and affordable network for customers as described in this Section 6.3. The backdrop against the technology investments included in this Section 6.3 is that there is more data available today than ever (and there will be even more in the future), and that data is changing the art of the possible for how the Company can best serve customers, including how to communicate with customers, develop and offer new customer programs, connect customers to the network, and plan, build, and operate the network to power the lives of customers.

Maturing how data is captured and managed will need to be an ongoing effort that will be informed by new technologies, lessons learned, and changing customer and stakeholder needs. The Company's path to increase customer choice, improve speed of DER interconnection, and enable more dynamic grid management to both accommodate and leverage the power of connected devices on the network via DERMS and AMI requires that the Company invests in multiple areas including people, process, and technology. As described below some of these data investments are “Pre-Authorized” investments for which the Company already has approved funding, and other investments are considered “net new” and required to support the envisioned future electric network as part of this Future Grid Plan.

Approved investments:

As part of the GMP, the Company has authorization to invest in the buildout of foundational data capabilities and will continue to expand and scale these data investments as part of the “core” expenditure. Therefore, the Company is not proposing costs for foundational data investments as part of its Future Grid Plan. However, they are described here briefly since they are critical to delivering the smarter network envisioned. Key features of the Company’s foundational data investments include:

- **Data accessibility**. Data is available “when and how it is needed” via investments to centralize data from enterprise systems and other data sources to an electric data platform.
- **Data quality**. Data is of the right content and quality to support relevant business processes via investments in data quality management tools.
- **Data management**. Investments to develop and implement data stewardship, management processes, management, and security across data products.
- **Data interoperability**. Ensure data can be related across all domains via a “One Model” that functions as the single source of truth on which authoritative sourcing, data governance, and data quality are based. Modernize asset and connected network model extracts from GIS to both geospatial and tabular formats.
- **Data insights.** Decisions and actions are data-driven based on the development and delivery of reports and dashboards to deliver insights to support grid modernization and other business processes.

Plan Investments:

As part of this Plan, the Company proposes the following incremental data investments (described in Section 6.3.2.5.1 – 6.3.2.5.3) to support the further integration of DER onto the distribution network, including preparing the Company to reliably operate a more dynamic distribution network.

6.3.2.5.1 Intelligent Data Capture

This is a new proposed investment.

Building upon the pre-authorized data enhancement work, the next phase of the Company’s work will be focused on how data is acquired and assured, leveraging an investment called intelligent data capture. Electric network operations and planning are becoming more and more reliant on timely, accurate, and ever more granular data. Network management technologies like ADMS, DERMS, and FLISR all rely on data, and their potential to deliver more benefits at scale hinges on their ability to analyze, draw insights, and inform action based on faster and more granular data. At its core, data needs to be captured digitally. The Company has existing efforts that are helping facilitate data capture, particularly the advent of AMI, which will introduce massive amounts of new data to inform both

Company network operations and improve customer experiences. However, achieving the full vision of data-driven network planning and operations requires integrating data from various sources and capture techniques to ensure the Company has the insights it needs to integrate and manage increasing DER.

The Intelligent data capture investment will leverage machine learning (ML) and artificial intelligence (AI) to model, compare, and correct data based on aerial and ground based light detection and ranging (lidar) and photogrammetry. This, in conjunction with asset data, customer data, network models, and sensor data will allow the Company to provide data to ADMS and other tools to better understand, efficiently maintain, and operate the Company's network in an ever-changing configuration and conditions.

6.3.2.5.2 Grid Asset Data Enhancements

This is a new proposed investment.

The Company's pre-authorized data investments are a critical starting point, though further investment will be necessary to achieve the full data capabilities required to support future electric network planning and operations use cases. The outcomes of this work include fully digitized data processes, better leveraged AMI data in Company planning processes, better data to support DER digital product investments, and empowering greater data-driven decision making. Additionally, the Company will continue to drive data interoperability and facilitate wider availability and use of data, increasingly blurring any lines between informational technology (IT) and Operational Technology (OT) where critical to deliver positive customer outcomes.

This investment included in this plan will focus on:

- Delivering additional value from the Company's data platform and "One Model" by incorporating additional data sources to further enable business processes and tools.
- Continuing to mature the Company's data analytics and reporting capabilities, incorporating new tools and techniques - identifying opportunities to deliver more efficiently for Company customers. This includes ensuring that data catalogs and other metadata stay fit for purpose to enable ease of data discovery, sourcing, and use.
- Invest in people and data management capability by hiring additional personnel to deliver data-focused outcomes and embed data management stewardship within each area of the Electric Business.
- Implement a Master Data Management tool to ensure that key business and operational data is mastered and synchronized across the Company's enterprise systems from the authoritative "One Model" to assure that all processes are using the best data available.

6.3.2.5.3 Transactional Digital Twin

This is a new proposed investment.

Digital twins provide a virtual representation of the physical assets on our network. By pairing virtual assets with real-time data from the physical assets, a transactive digital twin can provide real-time visibility into the performance and health of our electric network. This can support a range of potential use cases, including those related to network planning, management, and operations (as described in item #5 below). For instance, a transactive digital twin can provide the underlying data and model to support a predictive maintenance digital product to ensure that crews are allocated most effectively to service assets at the right time.

Using SAFe the Company will scope features for its transactive digital twin capabilities based on the highest value use cases, which may vary in terms of underlying technology requirements, including those primarily related to the volume and latency of field data being input into the model. For example, operational use cases may require more real-time data exchange than planning use cases.

6.3.2.6 Asset Planning, Management, and Work Execution Digital Products

The Company is deploying new digital products across a variety of areas to transform the efficiency and effectiveness with which the Company plans, designs, builds, and operates the electric network. The Company proposes as part of this Future Grid Plan to develop and deploy these technologies, which will be critical to the Company's delivery of an electric network capable of supporting the Future Grid Plan objectives for DER and electrification adoption, and reliability and resiliency of the network. Using the SAFe framework for digital product delivery (see description in Section 6.3.1), the precise details and delivery mechanisms for each product, as well as the prioritization of specific product efforts relative to each other, may shift based on highest identified need. Thus, the Company discusses future digital product efforts thematically in this section and focuses on features that it expects to deploy, as well as expected customer benefits.

6.3.2.6.1 Planning the Network Digital Products

This is a new proposed investment.

To support the way the Company plans the network, the Company is deploying new digital products focused on how the Company identifies, designs, and scopes required network investments. The rapid pace of anticipated electrification and the uncertainty of how, when, and where load will grow across the network introduces novel challenges to the way that the Company plans the network. This increased complexity in network planning is only heightened by the increased reliance on the electric network as more customers depend on electricity for their heating and transportation needs, and the network encounters increased frequency and severity of extreme weather events. Further, the electrification of the transportation and heating sectors more broadly introduces a new set of stakeholders with whom the Company has not had to historically co-plan (e.g., Mass DOT on highway charging, gas utilities for decarbonization of heat).

New digital products that may aid in identifying, designing, and scoping network investments include:

- New integrated electric and gas planning tools to facilitate the co-planning across gas and electric networks required for an orderly decarbonization of the heating sector (see Section 11)[5];
- Deploying more intelligent, and partially automated engineering design work to expedite the planning process;
- Using historical data and predictive analytics for forecasting across projects and workplan;
- Visualization of the entire end-to-end project and program workflow to highlight and resolve workflow bottlenecks; and

[5] The costs associated with integrated electric and gas planning capabilities were developed separately from the rest of the planning the network digital products, and include costs associated with implementing a discovery consulting study to define the integrated planning process and technology needs, fund future technology developments, and on-board dedicated FTEs to support integrated planning efforts within engineering and customer functions.

- Condition-based and predictive maintenance so assets are fixed just ahead of failure to drive a more resilient network to meet increasing customer expectations and reduce cost.

The resulting benefits from these products will include:

- More robust network infrastructure decisions due to faster and more automated planning processes that will enable multiple scenario analyses. This is particularly important given the uncertainty in future load growth.
- More tactical and proactive buildout of electric network infrastructure to support pockets of electric heating and transportation based on integrated planning with non-electric sector partners.
- Customer bill savings due to a more orderly transition from gas heating to electric heating.
- Customer bill savings from right-on-time investments that help stretch asset life.
- Reduced customer outages from failed equipment.

6.3.2.6.2 Operating and Managing the Network Digital Products

This is a new proposed investment.

As more customers adopt EVs and EHPs, customers' dependency on a reliable and resilient electric network will further increase. The Company proposes to deploy new digital products capable of helping better prepare for major events and right-size and accelerate the Company's response to network damage.

These products may include:

- New prediction tools that draw insights from weather data, prior storm data and experiential inputs to "right-size" response resource needs during storms.
- New tools and processes to perform rapid damage assessment, including collecting information from multiple data sources such as drones and synthesizing those data insights to more precisely deploy crews based on identified damage.

The resulting benefits from these products will include:

- Faster restoration times and reduced customer interruption minutes.
- Customer bill savings by leveraging technology to supplement and/or reduce the need for on the ground damage assessment, particularly in difficult to reach locations, and thereby reducing operational costs.
- Safer outcomes for storm response crews and impacted customers due to more right-sized and proactive deployment of storm response crews ahead of major events.

6.3.2.6.3 Building the Network and Executing Work Digital Products

This is a new proposed investment.

The Company is committed to helping the Commonwealth achieve its Net Zero goals by accelerating customer adoption of electrified heating and transportation and the connection of DERs to the network. As Sections 6.5 through Section 6.10 highlight, to deliver an electric network to support these goals requires a significant amount of physical infrastructure buildout, including numerous complex and concurrent multi-year substation projects. The Company is prepared to meet these challenges with the support of new digital products to streamline the efficiency of existing processes across the work execution lifecycle, including permitting, scheduling, supply chain management, resource management, onboarding, and every step along the way.

These products may include:

- Real-time status visibility, routing, and automated notifications to ensure right materials, equipment, and people are in place and ready before a job begins via a dynamic work scheduler.
- Integrated single view of all right of ways (ROW), assets, construction, work in area, environmental, customer/property owner interactions, etc. to streamline the end-to-end process.

The resulting benefits from these products will include:

- Faster delivery of critical network infrastructure projects to keep pace with load growth from electrification. Automated and digitized work scheduling, preparation, and execution will increase field productivity to meet the rising volume of work (i.e., new connections, infrastructure build-out and maintenance) while maintaining cost efficiency on behalf of customers. This will be critical to ensure that the Company can build out the network quickly and cost-effectively and accelerate capital delivery wherever possible to keep up with the anticipated pace of electrification and DER adoption.
- Reduced likelihood of equipment overloads during build out period. As discussed in Section 6.4 through Section 6.10, where the proposed network infrastructure investments are described, there are several instances when the expected project implementation date may exceed the forecasted “need by date,” resulting in a gap period where equipment may overload during peak hours. Faster project delivery made possible by work execution digital products will help mitigate this risk and reduce the likelihood and severity of potential overloads.
- Customer bill savings resulting from more efficient management of workforce operations utilizing digital tools to lower operating costs.

6.3.2.7 Security

Cybersecurity investments have been approved in previous rate filings. The Company proposes to enhance these program through the Plan between 2025 and 2029.

Physical and cybersecurity to protect the distribution network as increasing numbers of grid modernization devices are added to the system are critical to managing the distribution system safely and reliably. The Company expects greater cyber and privacy threats to emerge as new, grid-connected technologies are introduced to the network. Monitoring and control capabilities must proactively include physical and cybersecurity solutions into distribution network designs and processes rather than reactively as a retrofit or after-thought.

The risk from cybersecurity is increasing because:

- Greater complexity increases exposure to potential attackers and unintentional errors.
- Although there are associated benefits with linked networks (including data consolidation and improved visibility), networks that link more frequently to other networks introduce common vulnerabilities that may span multiple systems and increase the potential for cascading failures.
- More interconnections present increased opportunities for "denial of service" attacks, introduction of malicious code (in software/firmware) or compromised hardware, and related types of attacks and intrusions.
- As the number of network nodes increases, the number of entry points and paths that potential adversaries might exploit also increases.
- Increased data gathering and a shift towards two-way information flow increases the potential compromise of data integrity and confidentiality of data, resulting in potential data breaches, customer privacy intrusions or system compromise.

The Company is actively working to mitigate these highlighted potential risks to ensure the distribution system is as reliable, safe, and cost-effective as possible.

Plan Investments:

As part of the Company's Future Grid Plan, the following incremental investments are being proposed to support enhanced cybersecurity concerns associated with the various changes the Company expects on the network related to the clean energy transformation. The Company has forecasted its security investments for each year to directly support the technology investments proposed in this Section 6.3. This will ensure that the network will be prepared for the specific incoming integrations and that any potential risks are managed safely and securely.

- **Device management** including effective network authentication and management, which will become increasingly important as the volume of connected devices exponentially increases. This also includes encryption (i.e., hardware versus software, speed, patch-ability) of data at rest, and in transit for "internet of things" devices.
- **Network convergence** including network security and communication protocols to integrate IT and OT, which will be become critical in instances where the segregation of the two is no longer appropriate.
- **Penetration testing**, including threat detection models and security testing, security operations, monitoring and response.
- **Security Orchestration Automation & Response (SOAR)**, which includes the ability to detect, mitigate and respond to security events through improved visibility, orchestration, automation, and data analysis.

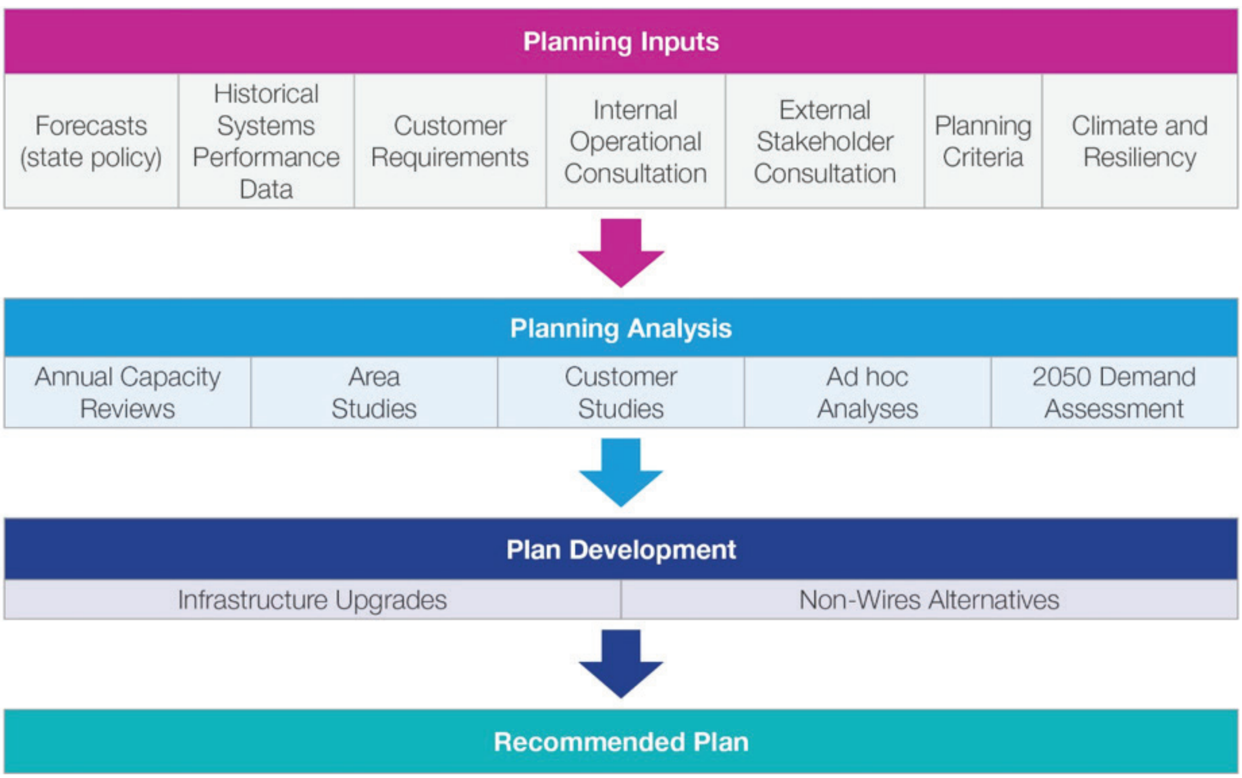
6.4 Planning Sub-Regions

This Section describes the planning methodology and approach that was used to develop the proposed network infrastructure investments included for each subregion in Section 6.5 through Section 6.10.

6.4.1 Overview of Planning Processes

As described in more detail below, the Company's Future Grid Plan analysis builds on the Company's existing and robust planning processes (i.e., Annual Capacity Reviews and Area Planning Studies) to identify the infrastructure upgrades and other investments needed to deliver on the Commonwealth's clean energy goals while ensuring a safe and reliable distribution system.

Exhibit 6.11: Plan Development Process



6.4.1.1 Annual Capacity Review

Annual capacity reviews identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies. - These capacity reviews consider actual observed feeder and transformer peak load values from the prior year adjusted per the latest annual forecast. The capacity planning process includes the following tasks:

- Review historical loading on each sub-transmission line, substation transformer, and distribution feeder.
- Apply and evaluate impacts of the weather adjustment and econometric forecast on future peak demand growth as per the Electric Peak (MW) Forecast.
- Analyze forecasted peak loads with comparison to equipment ratings.
- Consider system operational flexibility to respond to various contingency scenarios.

As part of this process, growth rates from the forecast are applied to each feeder and sub-transmission line in each area. Specific feeder, sub-transmission line, and/or transformer forecasts are adjusted to account for known spot load additions or subtractions, as well as planned load transfers due to system reconfigurations. Feeder and substation forecasted peak loads under the extreme weather scenario are used to prioritize and inform planning studies and to determine if the thermal capacity of facilities is adequate for future load level projections.

Individual project proposals are identified to address any imminent planning criteria violations. At a conceptual level, the Company prioritizes these small-scale project proposals and submits them for inclusion in future year capital work plans.

6.4.1.2 Area Planning Studies

Area Planning Studies are comprehensive reviews of the applicable study areas within the Company's service territory that result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10-to-15-year period. Area Planning Studies enhance the ability to meet obligations to provide safe, reliable, and efficient electric service for customers at reasonable costs.

The Company typically does an area planning study for a given study area every five to seven years. Annual Capacity Reviews assist in prioritization of Area Planning Studies. Areas with more normal and contingency overloads might be prioritized over areas with fewer issues identified in these Annual Capacity Reviews. Area Planning Studies are detailed, multi-step assessments that take several months to implement. Area Planning Studies consider all aspects of the needs in the targeted geographical and electrical area, including but not limited to all Distribution Planning Criteria violations, operational needs, external stakeholder consultation, and customer requests.

Area Planning Studies include the following stages:

- Stage 1: Definition of electrical and geographical scope of study and gathering necessary data needed to execute the study.
- Stage 2: Initial system assessment consisting of a quick analysis of facilities and system performance within the identified study geographic and electric scope.
- Stage 3: Study kick off meeting held to inform the larger stakeholder group that an area planning study is underway and to solicit input from those with knowledge of the system infrastructure in the area under review.
- Stage 4: Detailed system assessment and engineering analysis.
- Stage 5: Development and project estimating of alternative infrastructure and NWA plans.

- Stage 6: Review of various alternatives' relative costs and benefits and identification and finalization of a recommended plan.
- Stage 7: Technical review of the recommended plan by internal stakeholders.
- Stage 8: Delivery of area planning study report documentation upon completion of the study.
- Stage 9: Sanction of any recommended projects having forecasted spending within the next three fiscal years.

Additional planning activities include but are not limited to:

- DG System Impact Studies to identify any system modifications required to accommodate specific DG applications or groups of applications; Group Studies for DG interconnections form the basis for the CIP proposals discussed later in this Section.
- Large new customer load request reviews
- Review of acute reliability and other system performance concerns
- Operations and Control Center support
- Arc flash/fault duty customer requests

6.4.2 The Future Grid Plan (ESMP) Analysis

For the Future Grid Plan, the Company conducted engineering analysis for three planning horizons: 5-year (2029), 10-year (2034), and 2050 based on the electric peak forecasts produced by the Company's Electric Load Forecasting team as described in Section 5. This process applied the forecast across the Company's distribution system to evaluate the impacts of the forecasted adoption of electrification and DERs on the electric distribution network.

Section 6.5 through Section 6.10 contain the recommended scopes of work for each planning sub-region to address capacity deficiencies identified through this Future Grid Plan engineering analysis. Each section will describe the following categories of proposed incremental ESMP investments:

6.4.2.1 Major Substation and Feeder Projects

The ESMP analysis considered the future loading of major distribution equipment, primarily **substation transformers** and the capacity increases that will be necessary to support the forecasted load. The Company identified loading concerns emerging at substation transformers where the load on a transformer is forecasted to exceed 100% of normal equipment ratings and sized appropriate solutions to address the projected overloads. The Future Grid Plan engineering analysis assumed that certain infrastructure investments have already been made, including the Company's core network investment plan,[6] investments in pending CIPs,[7] and investments required to interconnect certain DG (i.e., solar PV and ESS projects) already in the study process. As such, the infrastructure investments identified from the ESMP engineering analysis are incremental investments needed to deliver on the Commonwealth's clean energy objectives.

[6] See the Company's petition for approval of base distribution rates and approval of a performance-based ratemaking plan (D.P.U. 23-150).

[7] See D.P.U. 22-61, D.P.U. 22-170, D.P.U. 23-06, D.P.U. 23-09, and D.P.U. 23-12.

In addition to substation transformers, the Company also identified normal loading constraints on its **distribution feeders** by comparing projected feeder loads against the applicable rating. Where forecast load growth caused equipment to exceed its ratings, the Company identified scopes of work to augment distribution capacity.

The proposed incremental ESMP investments will address projected asset overloads resulting from forecasted load growth associated with electrification of transportation and heat. However, as the Company invests in network infrastructure to expand its system capacity, these same investments will also address other primary goals of the Future Grid Plan. Specifically, these investments create hosting capacity to support more DERs like solar PV and ESS, and they improve reliability and resilience. Given the planning horizons (namely 2035 and 2050) and the scope (entire service territory at once), the Future Grid Plan engineering analysis focused primarily on normal capacity planning for major assets (i.e., substation transformers and distribution lines) using representative analysis to compare projected loads to asset ratings. Where available, the Company incorporated additional consideration of the following secondary drivers in the development of scopes to address the primary loading need:

- Contingency loading
- Asset condition
- Reliability and resiliency
- Protection and arc flash
- Safety and health

These substation projects will improve reliability and resiliency through the implementation of the latest Distribution Construction Standards. Distribution line scope development considered opportunities for the implementation of hardening methods such as spacer cable installation and expanded underground infrastructure where applicable to address resiliency considerations. Substation investments in locations identified as having a high risk of coastal flooding have incorporated flood mitigation considerations in the scope development.

To deliver increased capacity to meet the forecasted load growth in support of the Commonwealth's Net Zero goals, the Company must implement major substation construction projects, which can typically take between 5- and 10- years to complete. Because the Company took a long-term view of the investments required, it was able to anticipate the system needs for electrification forecast to occur beyond a typical 10–15-year study horizon. The investments included in this plan are prioritized based on forecasted demand, known and anticipated system capacity and operational needs, and customer expectations and requirements. Absent this long-term vision, the Company in many instances would have needed to make successive investments in an asset or area, to react to electrification load growth and clean energy deployment, as it materialized. This approach would result in less cohesive solutions and could ultimately result in more construction and associated costs overall, and delays in meeting customer and community needs. Instead, through this Plan, the Company is proposing a smarter, more efficient approach with more anticipatory investments scaled to the needs of an electrified and decarbonized Commonwealth.

To create an implementation schedule for the proposed Plan investments, the Company first developed project execution timelines based on each investment's level of complexity and risk. The in-service date for each investment was then calculated based on anticipated project timelines and capacity needs addressed by the project. Projects with lower complexity and risk were generally planned to be placed in service in the first five years, while projects with higher complexity or risk were forecasted to extend out into the 5–10-year horizon and beyond. Examples of such complexities include major transmission line extensions required to supply the expansion of an existing or the construction of a new substation, property acquisition for new substation sites or transmission lines, and significant prerequisite distribution line construction such as widescale conversion from a lower voltage (e.g., 4.16 kV) to a higher voltage (e.g., 13.2 kV or 13.8 kV). Execution risks and the methodology used to develop a delivery plan are described further in Section 7.1.1.

The Company will continuously adjust the delivery plan for Plan investments based on actual load growth experienced in each sub-region. The Company will reassess the projected load growth to consider recent actual performance and the latest forecast updates to reprioritize the investment portfolio on an annual basis as well as before each ESMP filing. During each annual capacity review, the Company will evaluate and adjust the implementation schedule of large projects recommended through Area Planning Studies. In addition to revising its annual forecasts, the Company may also evaluate the scope and timing of specific investments based on emergent factors such as load and DER customer spot loads and distribution system optimization capabilities.

Each of the sub-region-specific Sections (6.5 through 6.10) contains a table summarizing the capacity (both load-serving and hosting capacity) enabled by each substation investment.

6.4.2.2 Substation Projects to Address New Proposed CIP Investments

In addition to substation and feeder expansion projects to address electrification load growth constraints, the Company conducted analyses of potential substation projects currently in the process of group study for DER interconnection. As described in Section 4 and Section 7, the Company is proposing to apply the CIP cost allocation methodology to group studies that will be finalized and delivered following Department approval of the extension of that methodology. While the group studies described in Section 4 are still under study to further refine the expected system upgrades to interconnect the proposed group DER applications, the Company identified areas where sufficient solution maturity had been achieved as of this January 2024 ESMP to be able to perform an indicative cost allocation analysis. The purpose of this analysis is to give an indication of the potential costs and hosting capacity enabled for such projects and how they may help in achieving the Commonwealth's Net Zero goals. These group study solutions (inclusive of scope, cost, and enabled capacity) and preliminary cost allocation assumptions are still under study and subject to change, culminating in separate filings outside of this Plan.

The Company has group study processes underway at various levels of maturity in each of its six subregions. For purposes of this Plan, the Company has selected three of these group studies for the development of a preliminary CIP fee based on relative level of maturity and the current understanding of common system modifications required to interconnect the group DER as proposed.

The projects associated with these three group studies are described in further detail in Sections 6.5 through 6.10.

6.4.2.3 Enabled Load-Serving Capacity

All projects proposed through this Future Grid Plan will increase capacity in areas where projected overloads have been identified. The sub-region-specific sections contain summary tables of proposed projects, which include estimates of the MW capacity enabled for each substation project based on the substation transformer rated capacity.

These summary tables also include several distribution-feeder-only projects (i.e., projects that do not involve new substation transformers). However, because distribution feeder capacity is more geographically dependent on the emergence of load patterns such as spot loads, distribution capacity estimates for feeder projects are not included. These projects do enable capacity and address projected overloads due to electrification load growth; however, this capacity is only enabled at a more local level that cannot be as easily aggregated to the community or sub-region level. Therefore, distribution feeder projects have been marked as Not Applicable for “MW of enabled capacity” in the tables in the sub-region-specific sections.

6.4.2.4 Enabled Hosting Capacity

The MW capacity enabled is multi-use – meaning that while the primary driver of most of the proposed projects in this Plan is to increase load-serving capacity to support electrification load growth (e.g., from EVs and heating), the investments have a secondary benefit in that the increased transformer capacity can also enable the increased interconnection of DERs with export capabilities (e.g., PV and ESS), and thus enable additional hosting capacity. While there are some areas in the Company’s service territory that are hosting capacity-constrained (such as in the western part of the Commonwealth), in most areas the aggressive forecasted load growth prompted by electrification outpaces the impacts of the forecast adoption of DER. In other words, the Company’s system is generally more load-serving-capacity constrained than it is hosting capacity-constrained. Note that standalone ESS connections require both enabled load-serving capacity (for charging) and hosting capacity (for discharging), while PV and other generation-only DER only require sufficient hosting capacity. As with the enabled capacity definition above, the Company has quantified the increased hosting capacity by investment in terms of the incremental substation transformer rating. With this definition, increasing transformer ratings will increase both hosting capacity and enabled capacity equally. Thus, the estimated MW capacity values in the sub-region-specific tables below can also be used to indicate the estimated additional DG hosting capacity enabled on each substation.

As with load-serving capacity, substation transformers are typically the longest lead time component in projects to address hosting capacity limitations. While individual feeders and/or DER sites may have more localized hosting capacity constraints, these can generally be addressed through smaller scale, shorter duration projects to leverage that substation hosting capacity.

6.4.2.5 Non-Wires Alternatives

6.4.2.5.1 Approach to Non-Wires Alternatives

The Company defines Non-Wires Alternatives (NWAs) as the use of a non-traditional solution to a specific electric network constraint that defers or removes the need to construct or upgrade specific components, or reduces the operational risk related to a specific network constraint, on the distribution and/or transmission system.[8] NWAs could be comprised of Company- or customer-owned resources such as Energy Storage (ESS), Solar PV, localized Demand Response (DR), Electric Vehicle (EV) managed charging, localized Energy Efficiency (EE) measures, or new flexible interconnection technologies.

The Company has developed guidelines for the consideration of NWAs in the distribution planning process that are incorporated into Area Planning Studies. The goal of these guidelines is to develop a combination of "wires" solutions and NWAs that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. The Company screens investments for suitability for NWAs as part of its standard planning procedure based on the project type (e.g., load growth or reliability), cost of the traditional wires project, and anticipated in-service date.

As part of this Future Grid Plan, the Company has considered a broad set of investment alternatives and use cases for NWAs, including the following:

1. **Asset deferral:** In this use case, an NWA is used to defer the date by which the Company would otherwise have deployed a wires solution to address a need. National Grid has implemented a handful of examples of these projects in New York and Massachusetts.[9] These projects have so far primarily been cost-effective in areas where unique conditions driving high wires solution costs (e.g., the need to build long undersea cables in Nantucket) or slow demand growth helps to achieve longer duration deferral periods (i.e., 10+ years). To date, these NWAs typically leverage built-for-purpose asset-based solutions, such as the deployment of new solar and/or storage to meet capacity needs.

2) **Bridge to Wires:**[10] This NWA use case has emerged recently due to the accelerating demand growth from beneficial electrification. For a "Bridge to Wires" NWA, the Company is faced with an imminent need for a capital project, but that capital project cannot feasibly be delivered in time to address the need. In this case, the "Bridge to Wires" solutions can be deployed quickly to reduce peak demand or increase peak supply to help manage reliability during that gap period when overloads on the network may be expected during peak hours (e.g., instances that could otherwise require temporary solutions such as feeder ties, switching, spot generation, and potential for curtailing service to customers).

As discussed further in Section 6.5.2, the Company has identified two initial opportunities to use NWAs to defer network investments from its five-year Plan.

The Company has also identified several opportunities where the strategic deployment of "Bridge to Wires" NWAs may help maintain reliability in areas in which necessary infrastructure upgrades have a projected in-service date several years after when projected loading concerns first appear. In these instances, the use of a non-wires solution can reduce the risk of impacts from overloads during the period before an infrastructure upgrade can be deployed. "Bridge to Wires" solutions are critical in maintaining a safe and reliable network as the Company connects EVs and EHPs at a rapid pace while the Company must build out the network capacity to catch up to customer demand growth.

[8] https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/What-is-an-NWA

[9] The Company (via its transmission affiliate – New England Power Company) installed a 48 MWh battery storage facility on Nantucket in 2019 that helped to defer the implementation of an additional undersea sub-transmission cable. The Company's New York affiliate (Niagara Mohawk Power Company), in 2022 operationalized an NWA to defer a distribution network investment in Cicero, New York comprised of distributed solar (15 MW) and storage (40 MWh) via a contracted partnership with Convergent Energy & Power.

[10] "Bridge to Wires" is a recent term of art for certain NWA use cases that the Company credits to Consolidated Edison in New York.

The Company's approach to NWAs is technology-agnostic. For instance, NWAs can be comprised of active management of flexible demand (e.g., EVs, controllable thermostats), exporting DER (e.g., ESS, PV, vehicle to grid), and demand destruction (e.g., EE). These technologies can be aggregated together as Virtual Power Plants (VPPs) and/or provided through a flexibility marketplace. The success of these solutions hinges heavily on the Company's investments in two areas:

- **Enabling Technologies (Section 6.3)**: The Company's continued development of DERMS capabilities and other enabling technologies will establish the foundation for the Company to integrate and manage DER flexibility to reliability provide grid services to meet capacity needs.
- **Customer Solutions (Section 6.11)**: The Company's customer facing offerings will compensate customers and third parties for the flexibility services that they offer to the grid. These programs will leverage the DERMS technology investments to deliver services to the electric network that will transform the way the Company plans and operates the network.

The Company is relatively early on in its journey with NWAs and thus intends to use this Plan to successfully deploy these projects in prioritized, high-needs areas. In doing so, the Company will grow its capabilities, experience, and understanding of how to best deploy and scale these projects to support network planning and operations processes and accelerate the deployment of clean energy technologies across the network. The Company will also gather insights on the locational value of DER and learn how to best engage customers and third parties and effectively leverage their flexible assets based on uptake of new programs and offerings. Similarly, the broader industry (i.e., NWA partners such as technology vendors, third party aggregators, DER developers) will continue to learn and mature as well through the Company's NWA efforts over the course of the Plan period.

6.4.2.5.2 Regulatory framework for non-wires alternatives – Grid Services Compensation Fund

The establishment of an enabling regulatory framework is crucial to advancing the use of NWAs in the Commonwealth. The Company is proposing to establish a $50 million DER Grid Services Compensation Fund (GSCF) to support delivery of NWA projects over the five-year period. The fund would be used to recover costs associated with the new proposed NWA programs described in Section 6.11.2, including customer and third-party incentives for providing locational flexibility, as well as incremental administrative costs of running the programs and assessing the potential for the NWA projects. The fund would be used to cover costs associated with both "Bridge to Wires" NWAs as well as "asset deferral" NWAs as defined in Section 6.4.2.5.1. As noted, the Company's approach to NWAs is technology agnostic and participation would be open to a variety of potential participants, including residential and commercial customers, DER owners and operators, and third-party aggregators.

The proposed $50 million cap was determined based on a preliminary assessment of the expected magnitude of capacity needed and the estimated customer incentive level to drive sufficient volume of participation, as well as a preliminary assessment of the potential deferral value of the two candidate feeder expansion projects for which the Company intends to pursue asset deferral NWAs.

The Company's efforts in this space will also include participation in a joint study (Section 6.11.2.5) with the other EDCs and MassCEC to further explore the value of DER providing locational grid services to the utility based on characteristics such as technology, level of availability, and level of direct utility visibility and control.

For the next five years, pending approval of its cost recovery proposal, the Company would recover DER Grid Service Compensation Fund expenses up to the aforementioned budget cap via the Infrastructure, Safety, Reliability, and Electrification (ISRE) cost recovery mechanism proposed in the Company's pending distribution rate case. The Company would report on its usage of the DER Grid Service Compensation Fund as part of its annual ISRE cost recovery filing.

While the Company plans to advance its capabilities to implement NWAs through this proceeding, new regulatory frameworks including shared savings mechanisms will be necessary to support scaling of NWA efforts and sustained EDC innovation and performance to achieve customer benefits via infrastructure deferral. The Company may propose such a mechanism in the future as further information is developed for the specific opportunities that have been identified in this Plan.

6.4.2.5.3 NWA Strategy and Future Vision: Accelerating Non-Wires Alternatives and Virtual Power Plants

As the Company enters a period of substantial growth in both expected customer load as well as deployment of controllable DERs and new grid modernization technologies, the Company is reimagining the art of the possible with Non-wires Alternatives. Consistent with the US DOE,[11] the Company sees a growing role for customer and third-party resources aggregated together as virtual power plants to provide cost-effective and reliable grid services, and the Company is using this Plan to build towards that future.

[11] U.S. DOE, "Pathways to Commercial Liftoff: Virtual Power Plants," September 2023, available at: https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

1. Virtual Power Plants

- **What are virtual power plants?** A virtual power plant is an aggregation of DERs that can balance electrical demand and supply and provide utility scale and utility-grade services like a traditional power plant.[12] VPPs can include energy efficiency, demand response, energy storage, EV managed charging, solar, and other distributed technologies located at residential, commercial, and front-of-the meter customer premises.

- **How are VPPs being used on National Grid's system today?** VPPs are used today primarily to provide system-level benefits in the form of system peak shaving.The Company administers an industry-leading DR VPP program called ConnectedSolutions that provides system peak shaving benefits by dispatching a variety of DR technologies at residential and commercial facilities across the Company's network. DR aggregators are also eligible to participate directly in the ISO-NE wholesale markets. The Company also administers an EV managed charging program that functions as a VPP by aggregating and shifting EV load away from system peak.

- **Can VPPs be used as non-wires alternatives?** VPPs that can be managed reliably to provide grid services based on a local grid constraint can be used as NWAs. This requires new capabilities and processes beyond those required to administer system peak VPPs, such as DERMS technology, including local short-term forecasting and grid dispatching, new customer programs and rate structures, and new operational and planning processes.

2. How is the Company through its Future Grid Plan evolving the way it uses VPPs?

The Company is taking a comprehensive approach to maximize the benefits that VPPs can provide to its network.

- **Scale existing VPP programs:** The Company will continue to grow its existing ConnectedSolutions and EV off-peak managed charging programs, which provide system-level peak shaving across the network.

- **Unlock VPPs as Distribution NWAs:** In this ESMP, the Company is investing in the necessary technology, customer programs, and policy enablers to amplify the benefits that VPPs can provide to the network as NWAs. The Company is investing in new DERMS and related technology capabilities (Section 6.3), developing new customer-facing VPP programs for NWA (Section 6.11.2), and testing those new capabilities to provide real grid value – both for "Bridge to Wires" NWAs, as well as to defer two network infrastructure projects as described in Section 6.5.2.

- **Support new wholesale VPPs through FERC 2222:** National Grid-connected DERs are already able to participate as DR aggregations in the ISO-NE wholesale markets. With the advent of FERC 2222, the Company expects that the diversity and volume of DER aggregation participation in the wholesale market will further increase. The Company's DERMS proposal (see Section 6.3) includes deployment of new features to support customers' ability to enroll in new wholesale market participation models associated with FERC 2222.

[12] Ibid.

3. What will be different in the future?

The Company looks forward to the future benefits and opportunities this Plan will unlock for its customers with respect to NWAs and VPPs. The Company envisions a future in which it further embeds VPPs into the way it plans and operates the network. By maximizing the value of customer flexibility to cost-effectively defer network infrastructure investments, the Company also will enable savings and new earning opportunities for customers.

The Company envisions a "flexibility-first" approach to planning,[13] whereby the Company can compare the potential and cost of localized grid services to address network needs to traditional "wires" infrastructure and cost, and rapidly and reliably secure localized grid services where beneficial for customers. To get there the following must be achieved:

- More detailed understanding of cost-effectiveness of NWAs in comparison to wires solutions
- Measurability to evaluate and track NWA performance (e.g., leveraging new AMI capabilities for residential customers)
- Transparent and clear market offerings with compelling value proposition to flexibility service providers and simple/easy participation experience for customers (e.g., coordinated offerings with the ISO wholesale markets to support dual-participation)
- New grid planning and operations processes and functions to manage NWAs at scale (e.g., new distribution roles akin to how the ISO manages markets for the bulk system)
- Appropriate regulatory mechanisms to reward the cost-effective usage of NWAs

In that future, the Company envisions market products and a distribution grid services marketplace evolving to address a variety of grid needs and use cases.[14] To get there will be a journey, and the Company proposes using this Plan to start deploying and testing new market products and processes to procure and manage grid services (as described in Section 6.11).

6.4.2.6 Approach to Transmission Investments

The substation and line upgrade projects included in the in the tables in Section 6.5 – 6.10 below reflect the Company's distribution system investments. It is noted that many of the projects have associated transmission system investments which, for the Company, will be made by the Company's transmission affiliate and operator, New England Power Company (NEP). These investments will go through the normal transparent, FERC-regulated transmission processes with ISO-NE (Independent System Operator New England) for Transmission Local System Plans (LSP). For the Company, the high voltage side of a substation (i.e., 115kV), substation transformer, transmission tap line, and substation land are all NEP owned. For purposes of completeness, the project names and descriptions included in the below sections include descriptions of the associated transmission components for each location. Specific investment needs may change based on changing conditions over time.

[13] "Flexibility first" is an approach already adopted by the Company's UK affiliate, National Grid Electricity Distribution, which shares lessons learned and best practices with the Company.

[14] E.g., UK flexible power market includes four distinct distribution grid services market products https://www.flexiblepower.co.uk/about-flexibility-services

6.4.2.7 Policy Enablers for Realizing Future Grid Plan Benefits

Policy and regulatory changes will be essential to realize the clean energy, reliability, and customer benefits from the Company's Future Grid Plan. These changes are also essential to the Commonwealth's clean energy transition. While several such policy and regulatory changes are discussed in more detail throughout the Future Grid Plan, they are summarized here.

The Company has identified priority areas where action is needed:

1. Timely cost recovery for electricity network investment (Section 7.0):

Cost recovery mechanisms must be sufficient to ensure that network investment necessary to prepare the network for a reliable and resilient energy system that is capable of supporting beneficial electrification and renewable energy integration, including necessary incremental anticipatory investment to support expected demand. As part of the Company's pending distribution rate case, the Company has proposed a cost recovery mechanism that enables the Company to make the level of investment for the first five years of this Plan. If approved by the Department, this cost recovery mechanism will permit the Company to make the needed core and incremental investments as described herein to achieve the Commonwealth's Net Zero goals. This proposed cost recovery mechanism is similar to what is already in place for Company's incremental Grid Mod investments and will permit the timely recovery of any O&M and in-service capital investment up to a cap, subject to a prudency review in the year following the spend.

2. Siting and permitting (Section 7.3):

As discussed in this report, the magnitude of work required to meet the Commonwealth's goals and to deliver the required volume of projects is significant and unprecedented, and will be challenged by current timelines for project siting and permitting. Reforms to existing processes should streamline siting and permitting for clean energy infrastructure to reduce lead times for electric infrastructure projects while placing community engagement at the forefront.

3. Time-varying electric rates (Section 6.11, 9.6.2, 9.6.3):

Regulatory support for AMI-enabled advanced rate designs will be essential to provide customers with the opportunity to manage their energy usage in a way that allows them to manage their energy bills while also limiting growth in total energy system costs. For example, advanced rates can encourage customers to avoid energy use during high-cost times, reducing total system energy and generation capacity costs. Innovative rates can also encourage more efficient utilization of the distribution and transmission systems, reducing the overall level of network investment needed in support of the transition.

4. Flexible demand and non-wires alternatives (Section 6.11):

In addition to time-varying electric rates, new regulatory frameworks and policy support are needed to support development of customer offerings and NWA that can reduce the magnitude of demand growth from electrification and to mitigate or avoid local system constraints. Potential offerings to enable demand flexibility include expanded managed charging, and utility or third-party management of heat pumps and behind-the-meter storage. Regulatory and policy frameworks will be necessary to enable aggregation of the above in support of NWA that reduce the pace and scale of electric network build out and/or reduce the likelihood or severity of overloads on the network.

Regulatory and policy frameworks must provide sufficient customer compensation to encourage these resources to participate and establish rules for market participation, while providing a sustainable long-term lens through which NWA can be evaluated alongside traditional infrastructure solutions, including a shared savings mechanism.

5. Integrated energy planning (Section 11):

Integrated energy planning (IEP) will be essential to achieve the decarbonization goals and mandates of the Commonwealth while providing gas and electric customers with safe, reliable, and affordable service during the transition. An orderly transition to decarbonization that includes coordination and collaboration on gas and electric system planning and customer demand-side programs outside of traditional measures offers several potential solutions to optimize overall energy system costs and reliability but will require unprecedented coordination and information sharing across EDCs and LDCs. A critical near-term step is the establishment of a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, DOER, AGO, and key affected stakeholders (e.g., environmental, consumer). IEP 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, which will require development of new regulatory frameworks.

6. Prioritizing affordability, equity, and justice for all communities in the energy transition (Section 3.3)

Multiple policy and regulatory actions will be necessary to support an equitable clean energy transition. These include:

- Funding for expanded assistance programs and low-income bill discount programs, and customer outreach to support participation in such programs;
- Collaboration with utilities and community stakeholders to ensure effective outreach to customers and communities in initial stages of infrastructure and utility program development to develop awareness of forthcoming proposals and identify community priorities and concerns;
- Reforms that support the ability of customers in environmental justice populations, especially low-income customers, to participate in customer programs.
- Enhancing access to regulatory and policymaking processes in support of more equitable project and program outcomes; and
- Funding to support collaborative efforts to encourage a diverse clean energy workforce; and
- Collaboration with utilities and stakeholders to develop meaningful metrics that support objectives of increased access, engagement, and realization of program benefits in environmental justice communities.

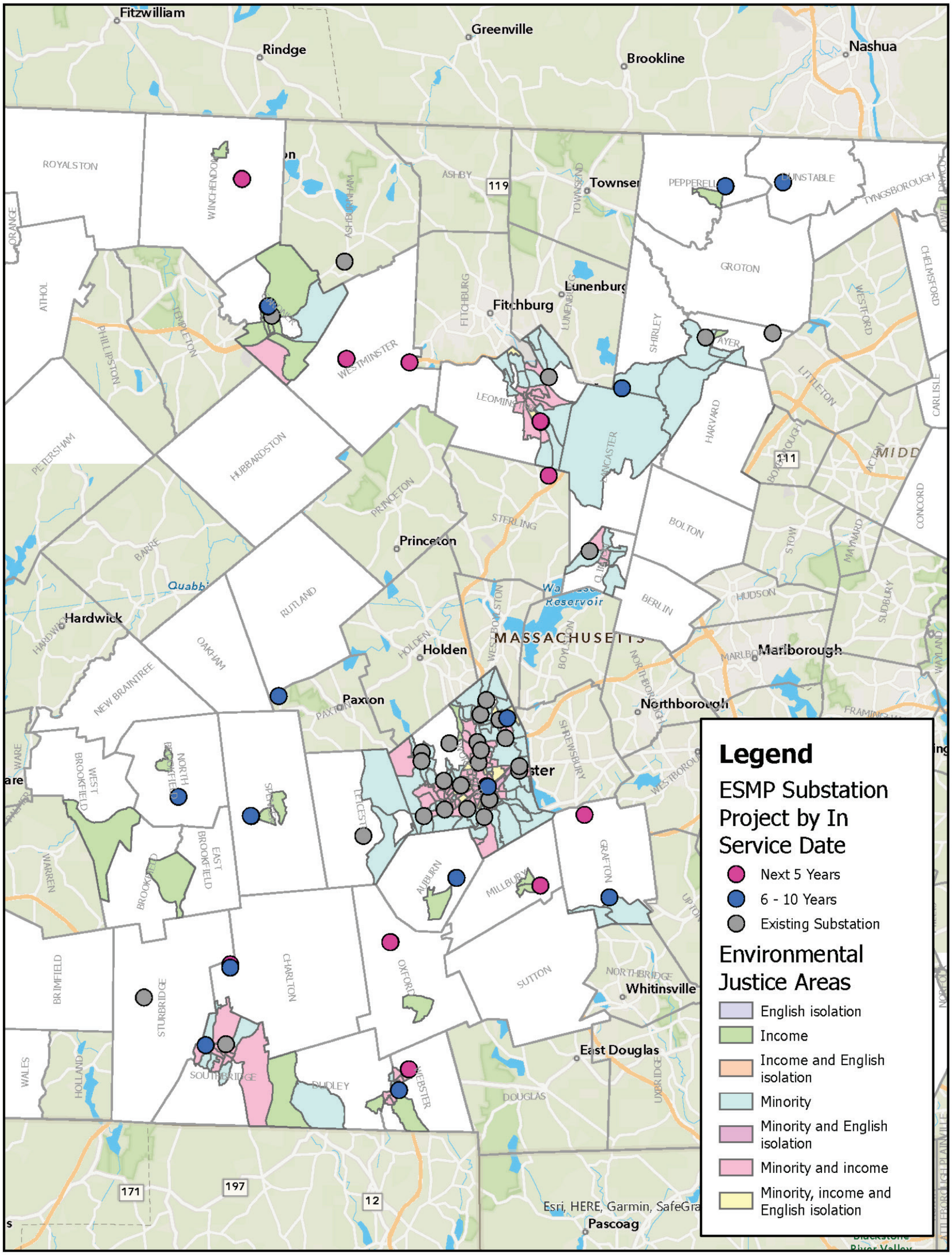
6.5 Central Sub-Region

6.5.1 Major Substation Projects

This Section summarizes the major required substation projects in the Central sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.12: Locations of the Future Grid Plan (ESMP) Substation Projects in Central Sub-Region by In Service Date



6.5.1.1 Major Substation Projects to Address Load-Growth

The five-year and 5- to 10-year network Investments identified in Exhibit 6.12 above and table below address normal thermal loading constraints projected in the five year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the vicinity surrounding the substation locations.

Exhibit 6.13 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings. This asset may be a substation transformer, distribution feeder, or a combination of multiple assets. For example, the Company is recommending the rebuild of its existing Pratts Junction Substation to increase capacity in the Leominster and Lancaster area. The need date for this investment, tied to the first area overloads experienced, is 2023. In this year, two feeders are projected to exceed their rated capacity. While operational measures and/or short-term projects could be employed to mitigate these feeder overloads, the Pratts Junction transformers are then expected to exceed their emergency ratings on contingency in 2024. By building out the long-term solution, the Company is ensuring that the Company does not need to come back to Pratts Junction multiple times over the next decade to increase capacity in a piecemeal and reactive manner, realizing efficiencies. Additionally, by establishing the incremental 66 MW of substation transformer capacity in 2029 through the completion of this project, the Company ensures that the capacity is ready for electrification as it materializes and so customers in this area will experience fewer delays in the ability to adopt electrification technologies.

Exhibit 6.13: Central Sub-Region Proposed Investments

Study Area	#	Project	Substation Location Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)[15]
Ayer Clinton	1	Laurel Circle Second Transformer	Shirley	2032	2033	66
Gardner Winchendon	2	Crystal Lake Feeder Expansion	Gardner	2033	2034	NA
	3	East Winchendon Second Transformer	Winchendon	2029	2028	66
	4	Westminster Rebuild	Westminster	2029	2028	66
	5	East Westminster Rebuild	Westminster	2029	2028	102
Leominster	6	Pratts Junction Rebuild	Sterling	2029	2023	66
	7	Litchfield Street Feeder Expansion	Leominster	2028	2028	NA

[15] "NA" indicates distribution feeder only project as described at the bottom of Section 6.4.

Millbury Grafton	8	North Grafton Second Transformer	Grafton	2028	2029	66
	9	New Substation Near Grafton	Grafton	2034	2026	132
	10	Pondville Rebuild	Auburn	2034	2035	85
	11	Millbury Feeder Expansion	Millbury	2027	2026	NA
Spencer Rutland	12	New Lashaway Feeder Expansion	North Brookfield	2034	2035	NA
	13	Meadow Street Feeder Expansion	Spencer	2030	2031	NA
	14	Treasure Valley Feeder Expansion	Paxton	2031	2032	NA
Webster Southbridge Charlton	15	East Webster Feeder Expansion	Webster	2027	2023	NA
	16	North Oxford Second Transformer	Oxford	2029	2030	66
	17	West Charlton Second Transformer	Charlton	2028	2025	66
	18	New Substation Near Southbridge	Southbridge	2034	2023	132
	19	New Substation Near Webster	Webster	2034	2023	132
	20	Charlton EV Highway Charging Station	Charlton	2034	2030	132
Worcester North	21	New Substation near Greendale	Worcester	2034	2025	132
	22	Worcester Backyard Conversion Program	Worcester	NA	NA	NA
Worcester South	23	Grafton Street Rebuild	Worcester	2034	2025	132
Pepperell Dunstable	24	Dunstable Feeder Expansion	Dunstable	2032	2033	NA
	25	Groton Street Rebuild	Pepperell	2033	2034	67

Additional details for each investment identified in Exhibit 6.13 above are provided below.

1. Laurel Circle Second Transformer

A new 115 to 13.8 kV transformer will be added to the Company's existing Laurel Circle substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Shirley area.

2. Crystal Lake Feeder Expansion

An additional two feeders will be added to the Company's existing Crystal Lake substation to support load growth primarily in the Gardner area.

3. East Winchendon Second Transformer

A new 115 to 13.8 kV transformer will be added to the Company's existing East Winchendon substation and will be supplied by a new 115 kV transmission line extension. One new 55 MVA transform will be installed with four distribution feeders to support the distribution loads primarily in the Winchendon area.

4. Westminster Rebuild

A new 69 to 13.8 kV transformer will be added to the Company's existing Westminster substation and will be supplied by existing 69 kV transmission lines. The existing transformer will be upgraded to 55 MVA, and one new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Gardner and Hubbardston areas.

5. East Westminster Rebuild

Both transformers at the Company's existing East Westminster substation will be upgraded and additional feeder positions added to support load growth primarily in the Westminster and Hubbardston areas.

6. Pratts Junction Rebuild

A new 115 to 13.8 kV substation will be installed next to the existing Pratts Junction substation to replace the existing 115 to 13.8 kV Pratts Junction substation. The new substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily in the Leominster and Lancaster areas.

7. Litchfield Street Feeder Expansion – NWA Project

Two additional feeders will be added to the Company's existing Litchfield St substation to support load growth primarily in the Leominster area.

8. North Grafton Second Transformer

A new 69 to 13.8 kV transformer will be added to the Company's existing North Grafton substation and will be supplied by existing 69 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Grafton area.

9. New Substation near Grafton

A new 115 to 13.8 kV substation near the Sutton and Grafton border would be supplied by a short extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the southeast of the Company's existing Millbury Substation.

10. Pondville Rebuild

The Company's existing Pondville Substation will be upgraded and supplied by existing 69kV transmission lines. The substation will be upgraded to include two 55 MVA transformers, with eight distribution feeders to support distribution load primarily in the Auburn area.

11. Millbury Feeder Expansion – NWA Project

An additional feeder will be added to the Company's existing Millbury substation to support load growth primarily in the Grafton, Millbury, and Sutton areas.

12. New Lashaway Feeder Expansion

An additional feeder will be added to the Company's existing Lashaway substation to support load growth primarily in the Brookfield, North Brookfield, and West Brookfield areas.

13. Meadow Street Feeder Expansion

An additional feeder will be added to the Company's existing Meadow St substation to support load growth primarily in the East Brookfield and Spencer areas.

14. Treasure Valley Feeder Expansion

The 55W3 feeder at the Company's existing Treasure Valley substation will be upgraded to support customer loads. The feeder only supports DER and does not have any feeder regulation.

15. East Webster Feeder Expansion

An additional two feeders will be added to the Company's existing East Webster substation to support load growth primarily in the Webster area.

16. North Oxford Second Transformer

A new 115 to 13.2 kV transformer will be added to the Company's existing North Oxford substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Oxford area.

17. West Charlton Second Transformer

A new 115 to 13.2 kV transformer will be added to the Company's existing West Charlton substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Charlton and Sturbridge areas.

18. New Substation near Southbridge

A new 115 to 13.2 kV substation near the Southbridge and Sturbridge border would be supplied by an extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the west of the Company's existing Snow St substation.

19. New Substation near Webster

A new 69 to 13.2 kV substation near the Dudley and Webster border would be supplied by extending 69kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the west of the Company's existing East Webster substation.

20. Charlton EV Highway Charging Station

To support highway electrification and meet the anticipated demand associated with EV charging infrastructure at the Charlton eastbound and westbound service plazas on I-90, a new 115 to 34.5 kV substation would be supplied from existing 115 kV transmission. Four underground 34.5 kV supply lines would serve the projected EV charging load, with full redundancy. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation.

21. New Substation near Greendale

A new 115 to 13.8 kV substation in the northern part of Worcester would be supplied by extending 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the south of the Company's existing Greendale substation. This includes supporting the retirement and conversion of existing 4 kV substations in the area.

22. Worcester Backyard Conversion Program

The Company's existing overhead backyard construction in Worcester will be replaced with dual ratio pad mounted min-pads or submersible transformers that will be installed on the road-side, with secondary cables running into the backyard. The dual ratio transformers will allow for future voltage conversion. The proposed solution will support the distribution load growth in the Worcester area and will reduce access issues during maintenance and restoration. The existing backyard construction is unable to support the projected electrification load growth; to increase capacity in these areas will require significant investment that will take place over many years as an enduring program that will encompass the 5- and 10-year plans and beyond.

23. Grafton Street Rebuild

At the Company's existing Grafton Substation, the substation will be rebuilt and supplied by a new 115 kV transmission line extension. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily in the central part of Worcester. The rebuilt substation will also support DER enablement by effectively grounding the 13.8 kV system and converting the existing 4 kV substations in the area.

24. Dunstable Feeder Expansion

An additional feeder will be added to the Company's existing Dunstable substation to support load growth primarily in the Dunstable area.

25. Groton Street Rebuild

The Company's existing Groton St Substation will be upgraded and supplied by existing 69kV transmission lines. The substation will be upgraded to include two 40 MVA transformers, with six distribution feeders to support distribution load primarily in the Pepperell area.

6.5.1.2 Major Substation Projects to Address DER Interconnection Needs

As of January 2024, the Company did not identify any in-progress group studies in the Central sub-region that were of sufficient maturity and included appropriate common system modifications to inform the development of an estimated CIP fee at this time. As described in Section 4, the Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to group studies that are finalized and delivered following Department approval of the extension of that methodology, that is, to submit additional CIPs following approval of this Plan, as warranted.

6.5.2 Non-Wires Alternatives

Deferral NWAs

As discussed in Section 6.5.1, the Company identified two locations where it will pursue implementation of a non-wires-based project to meet the load-growth driven network need, and thus, attempt to defer the required network infrastructure investment. In these locations, the Company has conducted preliminary assessments, indicating that that the grid needs could be sufficiently met through deployment of the new targeted customer incentive programs and flexibility market solicitations described and proposed in Section 6.11. The Company evaluated the annual projected peak load growth for that region and the impact of that load growth on the specific distribution equipment and circuitry to define a "needs statement " (i.e., the amount of reliable load relief needed in a particular year and location). The Company then compared that needs statement to a preliminary assessment of the customer composition on that part of the network, including the expected future propensity for that region to provide more flexibility as DER adoption continues and future incentive programs and market products are deployed (see Section 6.11).

- **Litchfield Street Feeder Expansion**. The Company will prioritize delivery of a non-wires solution in the region surrounding Litchfield Street station in Leominster to defer the deployment of the project described above involving two additional feeders at Litchfield Street. The Company's screening evaluation suggests that the loading and contingency needs that the feeder expansion project would address in its first five-years could potentially be sufficiently and cost-effectively achieved with targeted deployment of the proposed non-wires alternative customer programs described in Section 6.11. Thus, the Company plans to pursue an NWA to defer the project from its 2028 in-service date to a 2033 in-service date.

- **Millbury Feeder Expansion**. The Company will prioritize delivery of a non-wires solution in the region surrounding Millbury station in Millbury to defer the deployment of the project described above involving one additional feeder at Litchfield Street. The Company's screening evaluation suggests that the loading and contingency needs that the feeder expansion project would address in its first five-years could potentially be sufficiently and cost-effectively achieved with targeted deployment of the proposed non-wires alternative customer programs described in Section 6.11. Thus, the Company plans to pursue an NWA to defer the project from its 2027 in-service date to a 2032 in-service date.

The Company conducted an NWA suitability review of the other substation and feeder expansion projects scheduled to be in-service by 2029. The suitability criteria used to evaluate the NWA potential for each project considered project lead time (i.e., how long would it take to implement the wires solution), grid needs statement, customer propensity to provide flexibility, and cost-effectiveness. The Company chose to focus on feeder expansion projects for the initial NWAs rather than substation projects because of the long project lead times associated with constructing and delivering substation projects, the substantial projected overloads that the substation projects would be used to address by enabling clean energy capacity, and the uncertainty related to the success of NWAs. In contrast to substation projects, feeder expansion projects generally have shorter project implementation timelines (as short as 1-2 years), and address smaller capacity constraints that can more realistically be addressed by an NWA based on the Company's projection of its capabilities and customer propensity over the next five years.

For the feeder expansion projects, the Company conducted an evaluation of the grid needs from a planning perspective, as well as the customer composition and propensity to provide flexibility on that part of the network. The Company concluded that the grid needs likely could not be sufficiently and reliably achieved via activation of customer flexibility, and that the prudent solution to support the expected load growth from EV and EHP adoption is to pursue the wires solutions with the exception of the two feeder expansion projects described above.

As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with these two deferral projects and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

The Company has developed plans to implement and deliver network capacity by when it is forecasted to be needed across the network. However, there are several instances when the expected project implementation date is after the forecasted "need by date," resulting in a gap period where equipment may overload during peak hours. When this occurs, the Company pursues interim or emergency operational measures to mitigate the risk that a peak demand period could cause significant equipment damage that could result in long-duration outages. The Company intends to carefully monitor the load growth at these sites as part of its Annual Planning Review processes and appropriately manage the overload risk, including by evaluating the potential deployment of temporary solutions where needed. These temporary solutions may include load transfers to other substations via distribution ties, temporary spot generation deployment, and NWAs.

The Company will prioritize delivery of "Bridge to Wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be constructed in areas that have the most significant overloading risk.

In the Central sub-region the Company has identified six preliminary candidate locations for "Bridge to Wires" NWA projects, which were selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.14 below identifies the NWA candidate projects in the Central sub-region. Numbering follows Exhibit 6.13 above of all proposed Central sub-region investments.

Exhibit 6.14: NWA Projects in Central Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
6	Pratts Junction Rebuild	Sterling	2029	2023
9	New Substation Near Grafton	Grafton	2034	2026
15	East Webster Feeder Expansion	Webster	2029	2023
18	New Substation Near Southbridge	Southbridge	2034	2023
19	New Substation Near Webster	Webster	2034	2023
21	New Substation near Greendale	Worcester	2034	2025
23	Grafton Street Rebuild	Worcester	2034	2025

The above table reflects a list of potential candidate locations. Through this Plan term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that area. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list included above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-party participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front-of-the-meter PV and/or ESS facilities. Through this ESMP, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.5.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.5.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.5.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Worcester Community Action Council
- Central Massachusetts Regional Planning Commission
- Worcester Roots

- Leominster Community Action Counsel
- Spanish American Center of Leominster
- Regional Environmental Council of Worcester

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

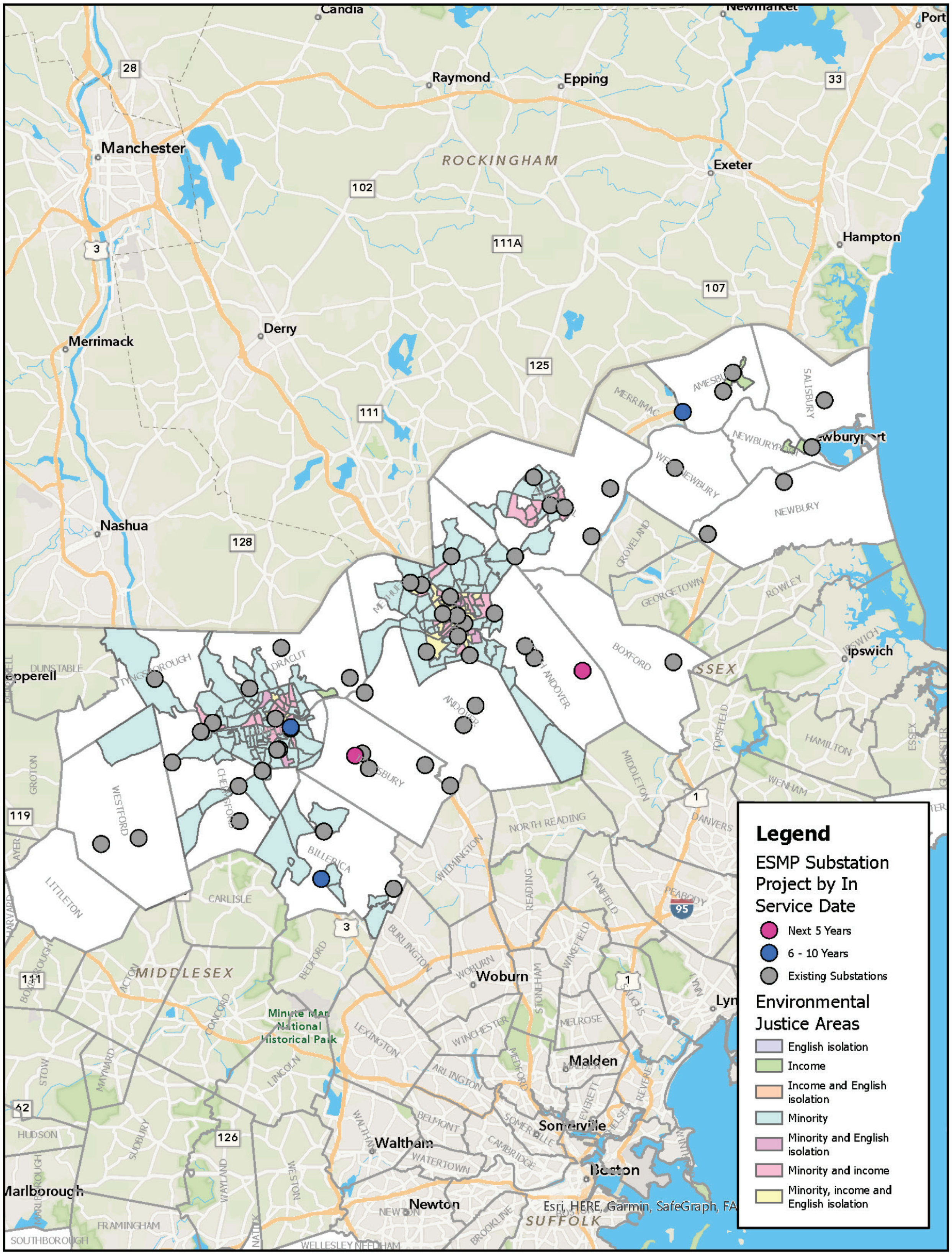
6.6 Merrimack Valley Sub-Region

6.6.1 Major Substation Projects

This Section summarizes the major required substation projects in the Merrimack Valley sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.15: Locations of the Future Grid Plan (ESMP) Substation Projects in Merrimack Valley Sub-Region by In Service Date



6.6.1.1 Major Substation Projects to Address Load Growth

The investments identified in Exhibit 6.15 above and table below address normal thermal loading constraints projected in the five year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.16 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Exhibit 6.16 Merrimack Valley Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location - Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Amesbury/ Newburyport	1	West Amesbury Second Transformer	Amesbury	2032	2033	66
Billerica	2	South Billerica 18 Rebuild	Billerica	2034	2025	103
Lowell	3	Perry Street 3 Expansion	Lowell	2034	2034	80
North Andover	4	Woodchuck Hill Rebuild	North Andover	2029	2023	83
Tewksbury	5	Power Company Road Feeder Expansion	Tewksbury	2028	2025	NA

1. West Amesbury Second Transformer

A second 115 to 13.2 kV transformer will be added to the existing West Amesbury substation. This will be a new 55 MVA transformer, with four new distribution feeders to support distribution loads primarily located in the West Amesbury area.

2. South Billerica 18 Rebuild

The existing 23 to 13.2 kV South Billerica 18 substation will be converted to a 115 kV supply to increase its ability to support electrification load growth. An underground extension of area 115 kV transmission will supply the substation, which will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Billerica area.

3. Perry Street 3 Expansion

The existing Perry 3 substation will be upgraded with two 55 MVA transformers and a second 115 to 13.8kV metal-clad switchgear power station that includes eight feeder positions for 13.8kV distribution load in the Lowell area. An underground extension of the area 115kV transmission will supply the added transformer.

4. Woodchuck Hill Rebuild

The existing Woodchuck Hill 56 substation will be upgraded with two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the North Andover Area. A new 115kV transmission tap off of the C155N line will be needed to supply the added transformer.

5. Power Company Road Feeder Expansion

An additional two feeders will be added to the Company's existing Power Co Road 20 Substation to support load growth primarily in the Tewksbury area.

6.6.1.2 Major Substation Projects to Address DER Interconnection Needs

As of January 2024, the Company did not identify any in-progress group studies in the Merrimack Valley sub-region that were of sufficient maturity and included appropriate common system modifications to inform the development of an estimated CIP fee at this time. As described in Section 4, the Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to group studies that are finalized and delivered following Department approval of the extension of that methodology, that is, to submit additional CIPs following approval of this Plan, as warranted.

6.6.2 Non-Wire Alternatives

Deferral NWAs

The Company applied the same suitability criteria as those described in Section 6.5.2 to evaluate the NWA potential for this sub-region.

The Company did not identify any deferral NWA projects in this sub-region. As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with the two deferral projects in this Plan and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

As noted in Section 6.5.2, the Company will prioritize delivery of "Bridge to Wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be delivered.

In the Merrimack Valley sub-region the Company has identified three preliminary candidate locations for "Bridge to Wires" NWA projects, which was selected based on having a five-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.17 below identifies the NWA candidate projects in the Merrimack Valley sub-region. Numbering follows Exhibit 6.16 above of all proposed Merrimack Valley sub-region investments.

Exhibit 6.17: NWA Projects in the Merrimack Valley Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
2	South Billerica 18 Rebuild	Billerica	2034	2025
4	Woodchuck Hill Rebuild	North Andover	2029	2023

The above table reflects a list of potential candidate locations. Through this Plan term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that areas. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-entity participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front of the meter PV and/or ESS facilities. Through this Plan, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.6.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.6.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.6.5 Equity and EJ outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Merrimack Valley Planning Commission
- Community Teamwork
- Cambodia Mutual Assistance
- Greater Lawrence Community Action Council
- Middlesex 3 Coalition
- Lowell Chamber of Commerce
- Merrimack Valley Chamber of Commerce

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

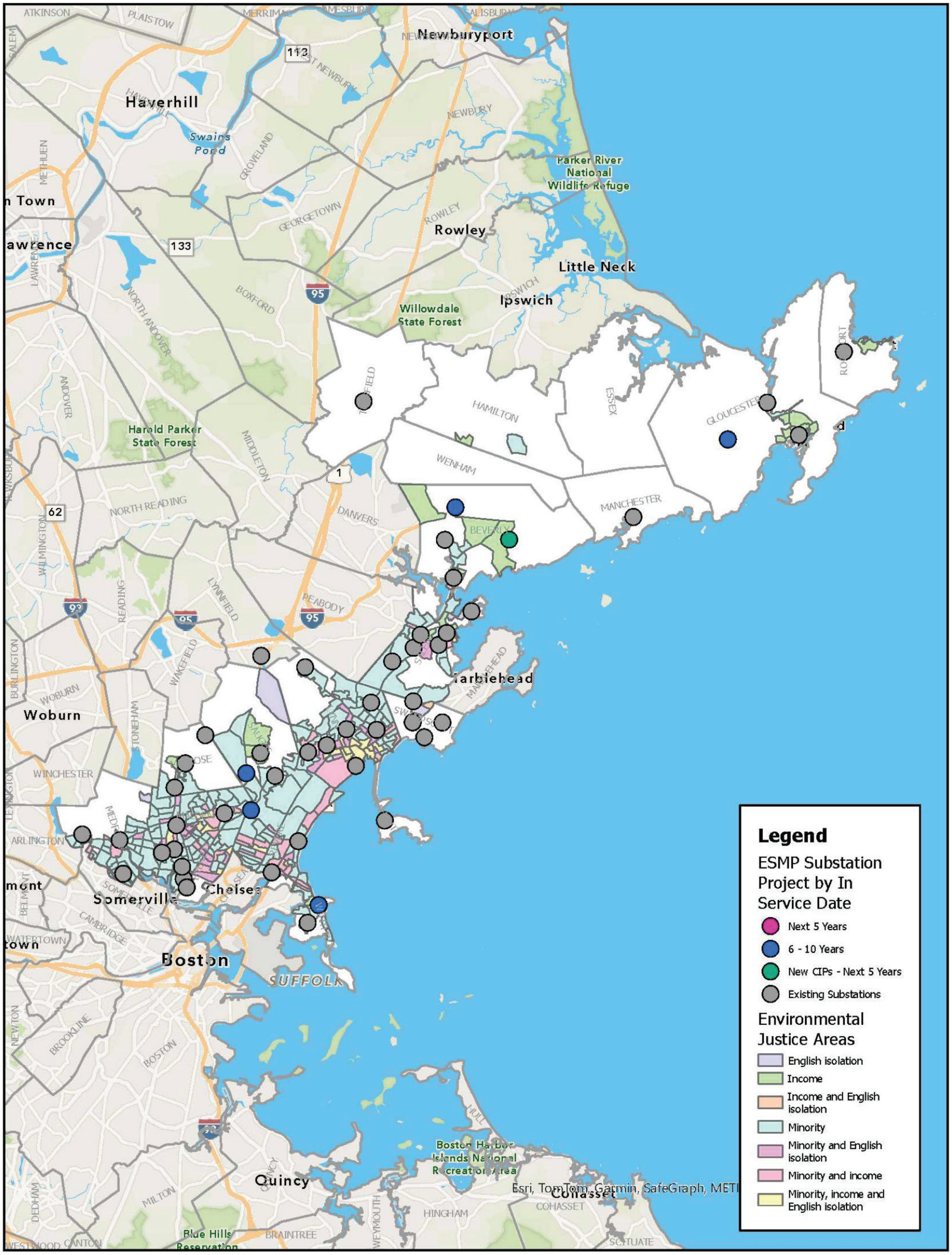
6.7 North Shore sub-region

6.7.1 Major substation projects

This subsection summarizes the major required substation projects in the North Shore sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.18: Locations of the Future Grid Plan (ESMP) Substation Projects in North Shore Sub-Region by In Service Date



6.7.1.1 Major Substation Projects to Address Load Constraints

The “Next 5 years” and “6-10 years” investments identified in Exhibit 6.18 above and table below address normal thermal loading. constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.19 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Exhibit 6.19: North Shore Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Melrose Saugus	1	New Substation Near Malden	Malden	2031	2023	132
	2	New Substation Near Saugus	Saugus	2034	2028	132
Revere Winthrop	3	Winthrop 22 Rebuild	Winthrop	2032	2033	132
Cape Ann	4	West Gloucester Feeder Expansion	Gloucester	2032	2033	NA
Beverly	5	North Beverly Rebuild	Beverly	2033	2034	132

1. New Substation Near Malden

A new 115 to 13.8 kV substation will be built near Squire Road in east Malden, supplied by the nearby area 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Malden and relieve loading on the existing Maplewood substation.

2. New Substation Near Saugus

A new 115 to 13.8 kV substation will be built in Saugus, supplied by the existing nearby 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Saugus and Revere areas.

3. Winthrop 22 Rebuild

The existing 4kV yard at Winthrop 22 will be converted to 13kV along with all associated loads and assets to meet the anticipated load growth in the area.

4. West Gloucester Feeder Expansion

An additional 23/13kV modular feeder will be added to the Company's existing West Gloucester 28 substation to support load growth in the area.

5. North Beverly Rebuild

The existing North Beverly 18 substation will be rebuilt from 23/4.16 kV to 23/13 kV with two 20 MVA transformers and six 13.8 kV distribution feeders that will provide additional distribution capacity to meet the forecasted load growth through the conversion of the existing 4.16 kV feeders.

6.7.1.2 Major Substation Projects to Address DER Interconnection Needs

Group Study	#	Project Name	Substation Location - Municipality	Projected In Service Date	Enabled Substation Capacity (MW)
Cape Ann 001	1	East Beverly 34.5 kV Upgrades – CIP Proposal	Beverly	2029	87

1. East Beverly 34.5 kV Upgrades – CIP Proposal

The Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to this group study. To accommodate the approximately 15 MW of DER proposed to interconnect through the Cape Ann 001 Group Study, the Company has identified common system modifications, which include the upgrade of two 115/34.5 kV transformers, the installation of a new 34.5 kV feeder position, and approximately seven miles of distribution line construction. The location of these proposed substation upgrades is shown in the Exhibit 6.15 map at the start of this Section. As the Group Study is in progress as of January 2024, these modifications are subject to change and/or refinement through the completion of the study. An indicative CIP fee estimate was developed based on representative construction costs and consideration of the allocation of benefits, including the incremental 87 MW of substation transformer capacity to be installed. The Company anticipates that a CIP fee for this group study, pending the completion of the study analysis and further refinement of the costs and benefits, may be approximately $277 per kW.

6.7.2 Non-Wire Alternatives

Deferral NWAs

The Company applied the same suitability criteria as those described in Section 6.5.2 to evaluate the NWA potential for this sub-region.

The Company did not identify any deferral NWA projects in this sub-region. As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with the two deferral projects in this Plan and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

As noted in Section 6.5.2, the Company will prioritize delivery of “Bridge to Wires” NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be delivered.

In the North Shore sub-region the Company has identified two preliminary candidate locations for “Bridge to Wires” NWA projects, which were selected based on having a five-year or longer “gap period” between “need-by-date” and expected project completion date. Exhibit 6.20 below identifies the NWA candidate projects in the North Shore sub-region. Numbering follows Exhibit 6.19 above of all proposed North Shore sub-region investments.

Exhibit 6.20: NWA Projects in North Shore Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
1	New Substation Near Malden	Malden	2031	2023
2	New Substation Near Saugus	Saugus	2034	2028

The above table reflects a list of potential candidate locations. Through this Plan term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that areas. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list included above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-entity participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front of the meter PV and/or ESS facilities. Through this Plan, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.7.3 Alternative cost allocation approaches to interconnect solar projects – exploration of different approaches – pros and cons

Please see Section 7.1.2 Alternative Approaches to Financing.

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

Please see Section 7.1.2 Alternative Approaches to Financing.

6.7.5 Equity and EJ outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Salem Alliance for the Environment
- Essex County Community Foundation
- Community Action Programs Inter-City, Inc.
- Revere Cares
- NAACP Environmental Justice Committee- Mystic Valley Area
- LEO – Learning through Empowering Opportunities, Inc.
- Salvation Army Good Neighbor
- North Shore Community Action Program
- North Shore Chamber of Commerce
- Everett Chamber of Commerce

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

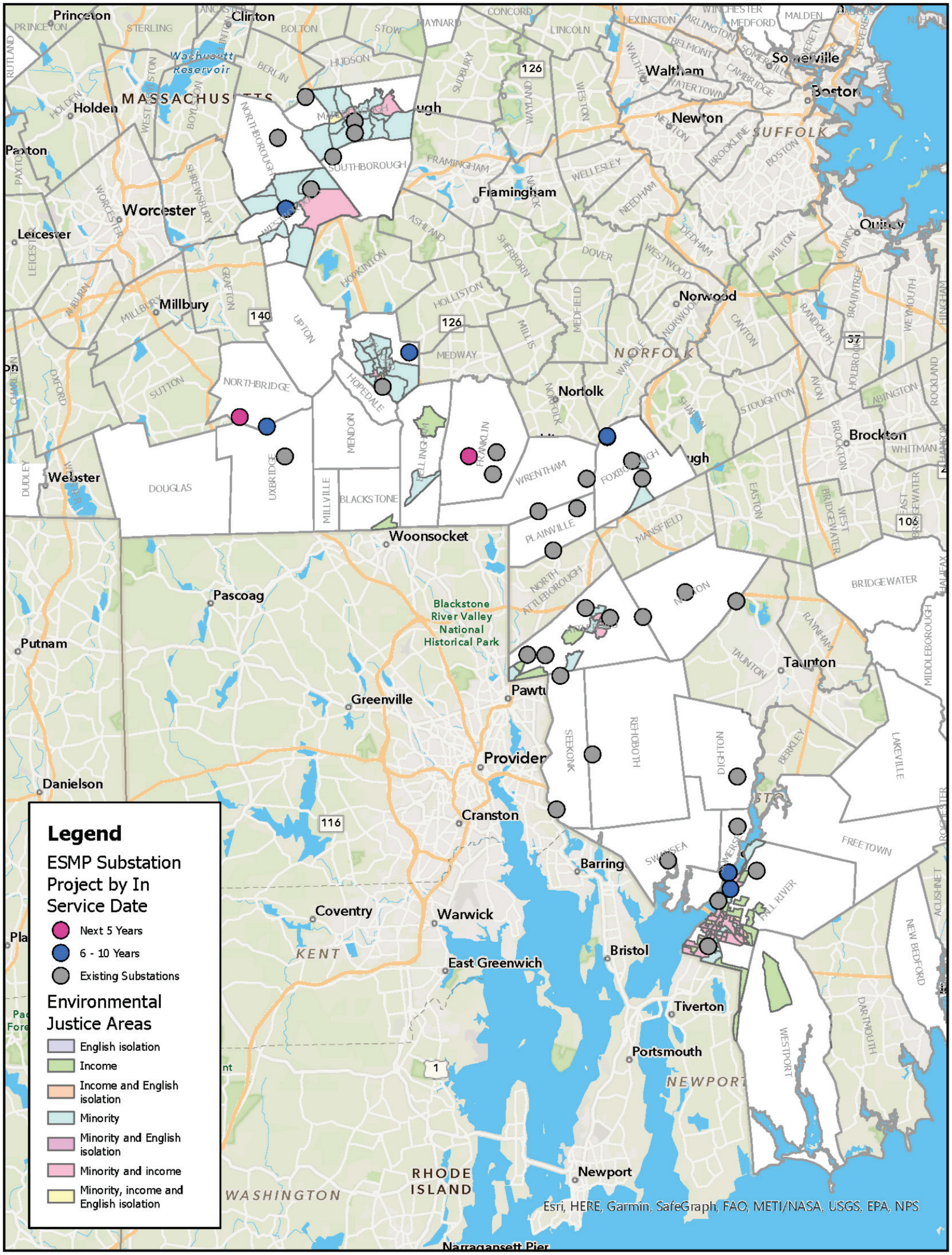
6.8 Southeast sub-region

6.8.1 Major substation projects

This Section summarizes the major required substation projects in the Southeast sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of Future Grid Plan substation projects by in service date.

Exhibit 6.21: Locations of the Future Grid Plan (ESMP) Substation Projects in Southeast Sub-Region by In Service Date



6.8.1.1 Major substation projects to address load growth

The investments identified in Exhibit 6.21 above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.22 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Exhibit 6.22: Southeast Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Fall River	1	New Substation Near Grand Army Highway	Fall River	2034	2026	132
Hopedale East	2	Beaver Pond Upgrade	Franklin	2029	2029	37
	3	New Substation in North Foxboro	Foxboro	2034	2023	118.8
Hopedale West	4	Rocky Hill Feeder Expansion	Milford	2031	2031	NA
	5	Whitins Pond Feeder Expansion	Northbridge	2027	2027	NA
	6	New Substation Near Northbridge and Uxbridge	Northbridge	2031	2027	132
Marlboro	7	Westborough EV Highway Charging Station	Westborough	2034	2030	132
Somerset	8	New Substation at Riverside	Swansea	2031	2023	124

1. New Substation Near Grand Army Highway

A new 115 to 13.8 kV substation near Grand Army Highway in Fall River would be supplied by an underground extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support the distribution load center primarily to the northeast of the Company's existing Hathaway Substation.

2. Beaver Pond Upgrade

The two existing 115 to 13.8 kV transformers at Beaver Pond Substation will be upgraded to 55 MVA to support distribution loads primarily in the Franklin and Bellingham areas.

3. New Substation in North Foxboro

A new 115 to 13.8 kV substation will be built in northern Foxboro, supplied by an underground line extension of area 115 kV transmission. The substation will consist of two 55 MVA transformers and eight distribution feeders that will primarily supply distribution load in the Foxboro area.

4. Rocky Hill Feeder Expansion

An additional three feeders will be added to the Company's existing Rocky Hill Substation to support load growth primarily in the Milford area.

5. Whitins Pond Feeder Expansion

An additional three feeders will be added to the Company's existing Whitins Pond Substation to support load growth primarily in the Milford area.

6. New Substation Near Northbridge and Uxbridge

A new 115 to 13.8 kV substation near the Northbridge and Uxbridge border would be supplied by an extension of existing 115 kV transmission lines. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation. Two 55 MVA transformers will be installed, with eight distribution feeders to support distribution load primarily to the northeast of the Company's existing Whitins Pond Substation.

7. Westborough EV Highway Charging Substation

To support highway electrification and meet the anticipated demand associated with EV charging infrastructure at the Westborough westbound service plaza on I-90, a new 115 to 34.5 kV substation would be supplied from existing 115 kV transmission. Two underground 34.5 kV supply lines would serve the projected EV charging load, with full redundancy. The final plans are dependent on land acquisition efforts that will determine the exact location for the new substation.

8. New Substation at Riverside

A new 115 to 13.8 kV substation at the location of the Company's existing Riverside Substation in Somerset will be supplied from existing 115 kV transmission. The new substation will require the retirement of the existing 4.16 kV substation and will consist of two 55 MVA transformers and eight distribution feeders to support distribution load growth in the Somerset and Swansea areas.

6.8.1.2 Major Substation Projects to Address DER Interconnection Needs

As of January 2024, the Company did not identify any in-progress group studies in the Southeast sub-region that were of sufficient maturity and included appropriate common system modifications to inform the development of an estimated CIP fee at this time. As described in Section 4, the Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to group studies that are finalized and delivered following Department approval of the extension of that methodology, that is, to submit additional CIPs following approval of this Plan, as warranted.

6.8.2 Non-Wire Alternatives

Deferral NWAs

The Company applied the same suitability criteria as those described in Section 6.5.2 to evaluate the NWA potential for this sub-region.

The Company did not identify any deferral NWA projects in this sub-region. As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with the two deferral projects in this Plan and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

As noted in Section 6.5.2, the Company will prioritize delivery of "Bridge to Wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be delivered.

In the Southeast sub-region the Company has identified three preliminary candidate locations for "Bridge to Wires" NWA projects, which was selected based on having a 5-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.23 below identifies the NWA candidate projects in the Southeast sub-region. Numbering follows Exhibit 6.22 above of all proposed Southeast sub-region investments.

Exhibit 6.23: NWA Projects in Southeast Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
1	New Substation Near Grand Army Highway	Fall River	2034	2026
3	New Substation in North Foxboro	Foxboro	2034	2023
8	New Substation at Riverside	Swansea	2031	2023

The above table reflects a list of potential candidate locations. Through this ESMP term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that areas. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list included above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-entity participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front of the meter PV and/or ESS facilities. Through this ESMP, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.8.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.8.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.8.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Groundwork South Coast
- Charles River Watershed Association
- Self Help
- Citizens for Citizens, Inc.
- Westborough CARES
- Source Hub US
- Southern Middlesex Opportunity Council

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

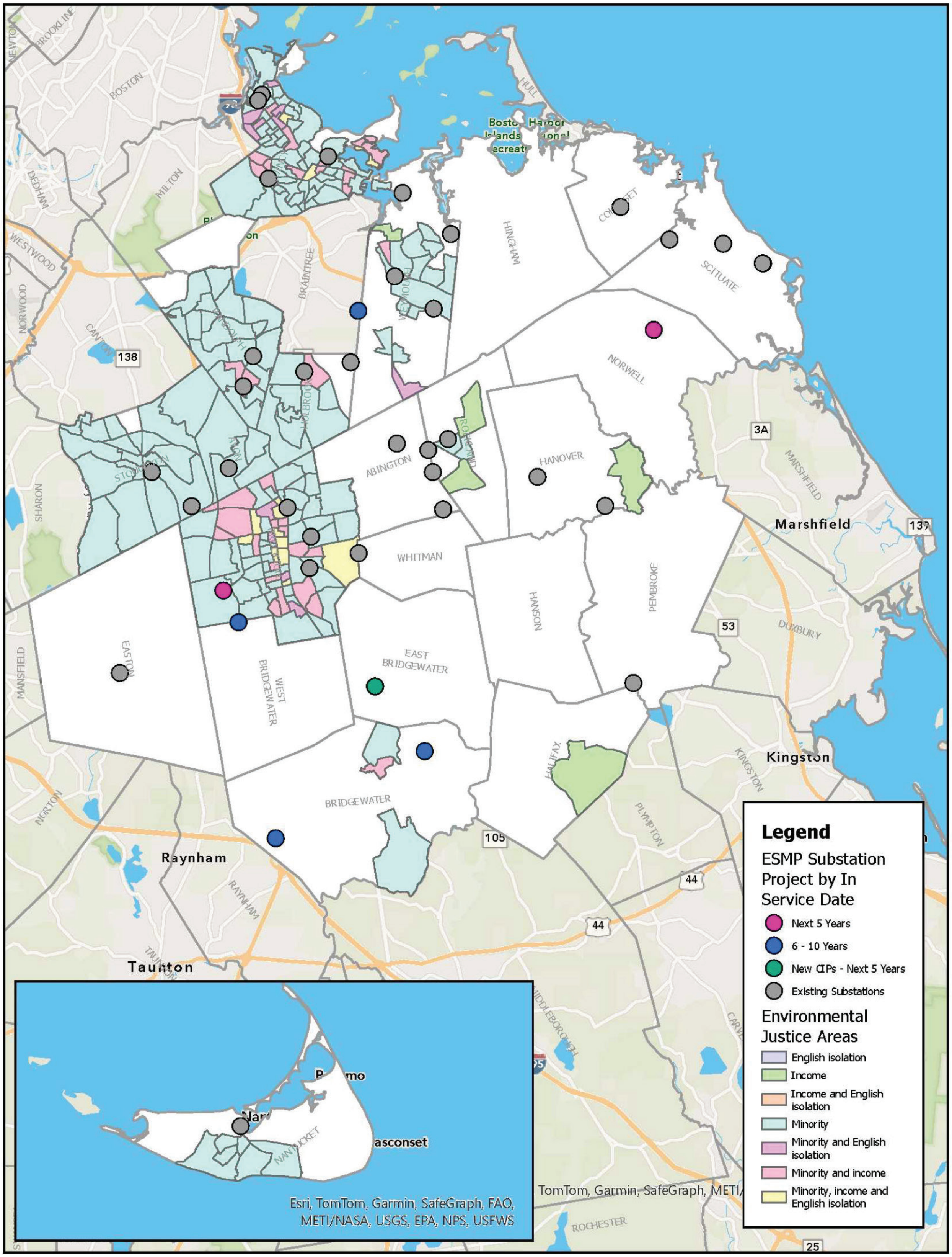
6.9 South Shore sub-region

6.9.1 Major substation projects

This Section summarizes the major required substation projects in the South Shore sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.24: Locations of the Future Grid Plan (ESMP) Substation Projects in South Shore Sub-Region by In Service Date



6.9.1.1 Major substation projects to address load growth

The investments identified in Exhibit 6.24 above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.25 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Exhibit 6.25: South Shore Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Bridgewater	1	Bridgewater EV Highway Charging Station	Bridgewater	2034	2030	132
	2	Mill St Rebuild	Bridgewater	2031	2029	83.5
Brockton	3	Belmont Second Transformer	Brockton	2029	2028	16
	4	New Substation Near Brockton and West Bridgewater	Brockton	2034	2028	132
Scituate	5	Norwell Upgrade	Norwell	2029	2028	NA
Weymouth	6	New Substation Near South Weymouth	Weymouth	2034	2025	132

1. Bridgewater EV Highway Charging Substation

As part of the Electric Sector Modernization Plan (ESMP), DPAM has identified the need to add a greenfield substation. It will be constructed on a Company-owned parcel adjacent to the span between E1 structures 191 and 192 to supply the Northbound and Southbound Service Plazas. The proposed substation will be supplied by a new loop on the 115kV E1 Transmission Line, consisting of an in-line breaker between two double span taps

2. Mill St 912 Rebuild

A new 115 to 13.8 kV substation located at the same parcel that the current Mill Street substation is located. The plans aim to remove the existing equipment at the substation and replace with a new substation with two 55 MVA transformers, with eight distribution feeders to support the distribution load center primarily in the south of the company's existing East Bridgewater Substation.

3. Belmont Substation Expansion Belmont Second Transformer

At the Company's existing Belmont Substation, a second 115 to 13.8 kV 55 MVA transformer will be installed, along with four additional distribution feeders. This will fully build out the Belmont substation with 2 55 MVA transformers and eight distribution feeders to support distribution load in the Brockton, Easton, and West Bridgewater areas.

4. New Substation Near Brockton and West Bridgewater

A new 115 to 13.8 kV substation south of the current Belmont Substation near the West Bridgewater and Brockton border. The substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed with eight distribution feeders to support distribution loads primarily located in the southern portion of the Brockton and Easton areas.

5. Norwell Upgrade

A replacement of the current transformer to a 55 MVA unit and an additional two feeders will be added to the Company's existing Norwell Substation to support load growth primarily in the Norwell and Scituate areas.

6. New Substation Near South Weymouth

A new 115 to 13.8 kV substation south of the current Mid Weymouth substation in southern Weymouth. The substation will be supplied by existing 115 kV transmission lines. Two 55 MVA transformers will be installed with eight distribution feeders to support distribution loads primarily located in the southern Weymouth area.

6.9.1.2 Major Substation Projects to Address DER Interconnection Needs

Group Study	#	Project Name	Substation Location - Municipality	Projected In Service Date	Enabled Substation Capacity (MW)
Bridgewater 001	1	East Bridgewater Upgrades – CIP Proposal	East Bridgewater	2029	45

1. East Bridgewater Upgrades – CIP Proposal

The Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to this group study. To accommodate the approximately 10 MW of DER proposed to interconnect through the Bridgewater 001 Group Study, the Company has identified common system modifications which include the upgrade of both 115/13.8 kV transformers at East Bridgewater Substation, the addition of a new 13.8 kV feeder position, and approximately 1.5 miles of distribution line construction. The location of these proposed substation upgrades is shown in the Exhibit 6.24 map at the start of this Section. As the Group Study is in progress as of January 2024, these modifications are subject to change and/or refinement through the completion of the study. An indicative CIP fee estimate was developed based on representative construction costs and consideration of the allocation of benefits, including the incremental 45 MW of substation transformer capacity to be installed. The Company anticipates that a CIP fee for this group study, pending the completion of the study analysis and further refinement of the costs and benefits, may approximate $192 per kW.

6.9.2 Non-Wire Alternatives

Deferral NWAs

The Company applied the same suitability criteria as those described in Section 6.5.2 to evaluate the NWA potential for this sub-region.

The Company did not identify any deferral NWA projects in this sub-region. As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with the two deferral projects in this Plan and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

As noted in Section 6.5.2, the Company will prioritize delivery of "Bridge to Wires" NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be delivered.

In the South Shore sub-region the Company has identified two preliminary candidate locations for "Bridge to Wires" NWA projects, which were selected based on having a five-year or longer "gap period" between "need-by-date" and expected project completion date. Exhibit 6.26 on the following page identifies the NWA candidate projects in the South Shore sub-region. Numbering follows Exhibit 6.25 above of all proposed South Shore sub-region investments.

Exhibit 6.26: NWA Projects in South Shore Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
4	New Substation Near Brockton and West Bridgewater	Brockton	2034	2028
6	New Substation Near South Weymouth	Weymouth	2034	2025

The above table reflects a list of potential candidate locations. Through this Plan term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that areas. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list included above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-entity participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front of the meter PV and/orESS facilities. Through this ESMP, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.9.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.9.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.9.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Southeastern Regional Planning and Economic Development District
- Sustainable Plymouth Coalition for Social Justice
- Nantucket Land Council
- Source Hub US
- Quincy Communication Action Programs
- Action for Boston Community Development, Inc.
- Community Action Programs Inter-City, Inc.
- Self Help, Inc.
- Executive Office of Veterans' Service Main Office
- ROCA
- South Shore Community Action Council

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

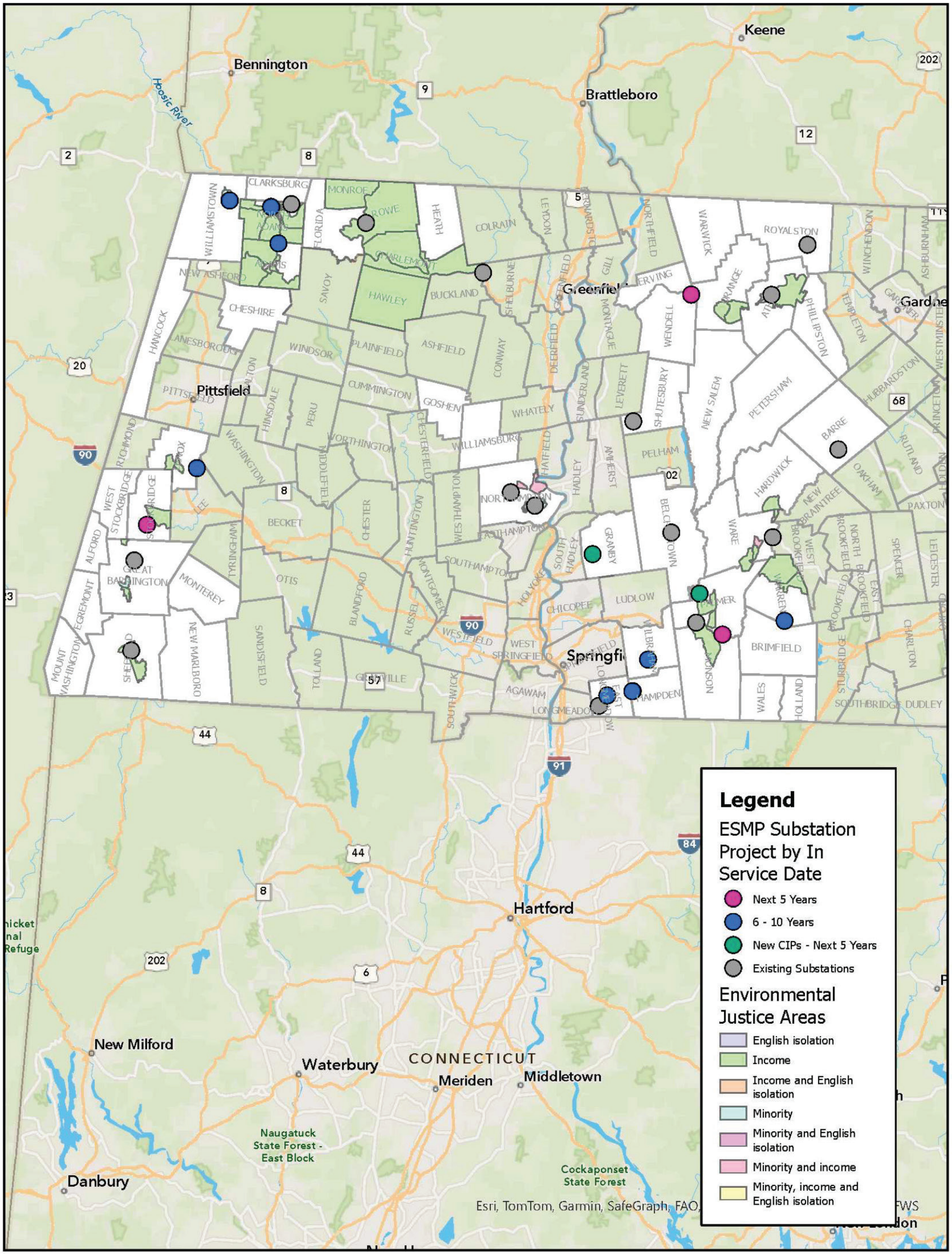
6.10 Western Sub-Region

6.10.1 Major substation projects

This Section summarizes the major required substation projects in the Western sub-region resulting from the Future Grid Plan analysis described in Section 6.4.

The map below shows the locations of the Future Grid Plan substation projects by in service date.

Exhibit 6.27: Locations of the Future Grid Plan (ESMP) Substation Projects in Western Sub-Region by In Service Date



6.10.1.1 Major Substation Projects to Address Load Growth

The investments identified in Exhibit 6.27 above and table below address normal thermal loading constraints projected in the five-year and ten-year planning horizons, and establish the capacity needed to support the forecasted load growth. Once implemented, these projects will position the local distribution system to accommodate electrification in a timely manner. The projects will also increase the reliability and resiliency experienced by all customers in the immediate vicinity of the projects, which may include those customers in the community where the substation is located and those in some surrounding communities. Exhibit 6.28 below indicates the first year that an asset addressed by the investment is projected to exceed its normal ratings; this asset may be a substation transformer, distribution feeder, or a combination of multiple assets.

Exhibit 6.28: Western Sub-Region Proposed Investments

Study Area	#	Project Name	Substation Location Municipality	Projected In Service Date	First Year of Overload	Enabled Substation Capacity (MW)
Adams Deerfield	1	Brown Street Rebuild	North Adams	2032	2033	36
	2	Adams Feeder Expansion	Adams	2032	2033	NA
	3	Williamstown Rebuild	Williamstown	2032	2033	53
Barre Athol	4	Wendell Depot Feeder Expansion	Wendell	2029	2029	NA
Monson Palmer	5	Little Rest Road Second Transformer	Warren	2032	2033	66
	6	East Longmeadow Feeder Expansion	East Longmeadow	2033	2034	NA
	7	Five Corners Feeder Expansion	Granby	2033	2034	NA
	8	Palmer Second Transformer	Palmer	2029	2028	62
	9	Thorndike Feeder Expansion	Palmer	2029	2028	NA
	10	West Hampden Second Transformer	Hampden	2032	2033	66
	11	Wilbraham Second Transformer	Wilbraham	2032	2033	66
Northampton Berkshire	12	Stockbridge Feeder Expansion	Stockbridge	2028	2028	11
	13	Lenox Depot Rebuild	Lenox	2029	2026	108

1. Brown Street Rebuild

The existing Brown St substation will be rebuilt and supplied by two 23 kV supply lines from the Adams substation and two 23 kV supply lines from the rebuilt Walker St substation. The rebuilt substation will consist of two 23/13.8 kV 20 MVA transformers and 4 feeder positions to support distribution load growth primarily in the North Adams and Williamstown area. Additional land around the substation or a new location may be required.

2. Adams Feeder Expansion

An additional feeder will be added to the Company's existing Adams substation to support load growth primarily in the Adams area.

3. Williamstown Rebuild

The existing Williamstown substation will be rebuilt and supplied by three 23 kV supply lines from the Brown St substation. The rebuilt substation will consist of three 23/13.8 kV 20 MVA transformers and 6 feeder positions to support distribution load growth primarily in the Williamstown area. Additional land around the substation or a new location may be required.

4. Wendell Depot Feeder Expansion

An additional two feeders will be added to the Company's existing Wendell Depot substation to support load growth primarily in the Orange area.

5. Little Rest Road Second Transformer

A new 115 to 13.2 kV transformer will be added to the Company's existing Little Rest Rd substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Brimfield, Holland, Wales, and Warren areas.

6. East Longmeadow Feeder Expansion

An additional feeder will be added to the Company's existing East Longmeadow substation to support load growth primarily in the East Longmeadow area.

7. Five Corners Feeder Expansion

An additional feeder will be added to the Company's existing Five Corners substation to support load growth primarily in the Granby area.

8. Palmer Second Transformer

A new 115 to 13.2 kV transformer will be added to the Company's existing Palmer substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Palmer and Monson areas.

9. Thorndike Feeder Expansion

Two new 13.2 kV feeders will be added to the Company's existing Thorndike substation. to support the distribution loads primarily in the Belchertown and Monson areas.

10. West Hampden Second Transformer

A new 115 to 13.2 kV transformer will be added to the Company's existing West Hampden substation and will be supplied by existing 115 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the East Longmeadow and Hampden areas.

11. Wilbraham Second Transformer

A new 69 to 13.2 kV transformer will be added to the Company's existing Wilbraham substation and will be supplied by existing 69 kV transmission lines. One new 55 MVA transformer will be installed with four distribution feeders to support the distribution loads primarily in the Wilbraham area.

12. Stockbridge Feeder Expansion

At the Company's existing Stockbridge Substation, a second modular feeder will be added. A second 23 to 13.8 kV transformer will be required to supply this new feeder. This project will support distribution load primarily in the Stockbridge area.

13. Lenox Depot Rebuild

At the Company's existing Lenox Depot Substation, the substation will be rebuilt and supplied by a 115 kV transmission line extension from the Woodland Rd substation (Eversource owned). The substation will consist of two 55 MVA transformers and eight distribution feeders to support the distribution loads primarily in the Lenox area. Additional land around the substation or a new location may be required.

6.10.1.2 Major Substation Projects to Address DER Interconnection Needs

Group Study	#	Project Name	Substation Location - Municipality	Projected In Service Date	Enabled Substation Capacity (MW)
Monson-Palmer-Longmeadow NW 002	1	Thorndike Second Transformer and Five Corners Rebuild – CIP Proposal	Palmer, Granby	2029	112

1. Thorndike Second Transformer and Five Corners Rebuild – CIP Proposal

The Company is proposing to apply the D.P.U. 20-75-B CIP cost allocation methodology, process and Provisional System Planning Provision to this group study. To accommodate the approximately 28 MW of DER proposed to interconnect through the Monson-Palmer-Longmeadow NW 002 Group Study, the Company has identified common system modifications, which include the addition of a second 115/13.2 kV transformer and a new feeder at Thorndike Substation, the rebuild of Five Corners Substation to include two 115/13.2 kV transformers, and approximately 2.5 miles of distribution line construction. The location of these proposed substation upgrades is shown in the Exhibit 6.24 map at the start of this Section. As the Group Study is in progress as of January 2024, these modifications are subject to change and/or refinement through the completion of the study. An indicative CIP fee estimate was developed based on representative construction costs and consideration of the allocation of benefits, including the incremental 112 MW of substation transformer capacity to be installed. The Company anticipates that a CIP fee for this group study, pending the completion of the study analysis and further refinement of the costs and benefits, may approximate $525 per kW.

6.10.2 Non-Wire Alternatives

Deferral NWAs

The Company applied the same suitability criteria as those described in Section 6.5.2 to evaluate the NWA potential for this sub-region.

The Company did not identify any deferral NWA projects in this sub-region. As the Company continues to progress the technology capabilities, and as the proliferation of DER continues to increase on the network, and the Company gains experience with the two deferral projects in this Plan and Bridge to Wires NWAs (see below), it expects there to be additional opportunities to explore deferral NWAs in the future.

Bridge to Wires NWAs

As noted in Section 6.5.2, the Company will prioritize delivery of “Bridge to Wires” NWA solutions to help reduce the likelihood and severity of expected overloads before needed network infrastructure projects can feasibly be delivered.

In the Western sub-region the Company has identified one preliminary candidate location for “Bridge to Wires” NWA projects, which was selected based on having a five-year or longer “gap period” between “need-by-date” and expected project completion date. Exhibit 6.29 below identifies the NWA candidate projects in the Western sub-region. Numbering follows Exhibit 6.28 above of all proposed Western sub-region investments.

Exhibit 6.29: NWA Projects in Western Sub-Region

#	Project	Substation Location - Municipality	Projected In Service Date	First Year of Overload
13	Lenox Depot Rebuild	Lenox	2034	2026

The above table reflects a potential candidate location. Through this Plan term, the Company will engage in detailed scoping efforts for these NWA opportunities in order to finalize the specific locations for Bridge to Wires NWA projects, and will review localized needs and capabilities as part of its Annual Capacity Review process. Initial detailed scoping and annual reviews will incorporate further analysis of the emerging forecasted system needs at each location, the availability of alternative operational measures to manage overloads (e.g., feeder switching, spot generation deployment), and an assessment of the customer propensity to provide flexibility in that area. Based on that further assessment, the Company may select Bridge to Wires locations at additional locations not included in the preliminary candidate list included above. The Company will also establish an annual process to make the Bridge to Wires project locations known to potential customer and third-entity participants who could earn value by providing grid services to address the bridge-to-wires needs (see Section 6.11).

As discussed in Section 6.11, the NWA solutions may be comprised of a variety of DER types, such as customer-sited EE and flexible demand like Wi-Fi-enabled thermostats and managed EV charging, as well as larger assets such as front of the meter PV and/or ESS facilities. Through this Plan, the Company intends to test multiple methods and gather valuable learnings on how to most effectively activate NWAs to deliver reliable load reductions to best address the local needs for that part of the network.

As policy, the industry, and the Company's NWA capabilities mature and as the load growth continues to materialize, the Company may reprioritize NWA delivery in different and/or additional locations as needed. The Company also may identify use cases to deploy NWAs to defer or avoid network infrastructure investments in addition to the "Bridge to Wires" use cases included in the table above.

6.10.3 Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.10.4 Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

Please see Section 7.1.2 Alternative Approaches to Financing.

6.10.5 Equity and EJ Outreach

Where the above projects have potential impact on EJCs, the Company is committed to ensuring that each community has a voice as energy infrastructure projects are developed. As projects are scoped, potential impacts on EJ populations will be actively considered. In addition, communities will be engaged early in the process so that the Company is able to discuss with them 1) the role the project plays in the distribution system, 2) the electrification benefits that will be realized by the local area, and 3) any community impacts that may be incurred due to construction or ongoing operations of the project. The Company is committed to understanding the perspectives, concerns, and priorities of each individual community that may be impacted by these projects as every neighborhood will be unique.

As discussed in Section 3, the Company has already begun engagement with EJ stakeholders around the Future Grid Plan. It is anticipated that potential organizations for engagement specific to projects identified would include, but not be limited to, organizations such as:

- Berkshire Regional Planning Commission
- Berkshire Funding Focus
- Berkshire Community Action Council

- NAACP Berkshires Environmental & Climate Justice Committee
- North Quabbin Community Coalition
- Community Action Pioneer Valley
- Markham-Nathan Fund for Social Justice
- Pioneer Valley Workers Center

The Company anticipates consulting with these groups early in the process in order to inform broader outreach efforts.

6.11 New Clean Energy Customer Solutions

To deliver on the Future Grid Plan objectives and continue to create value for customers, the Company's customer program offerings over the 5- and 10-year investment period will focus on the following (both through this Plan and through other regulatory proceedings, as outlined on Exhibit 6.30 on the following page:

1. Help customers improve their energy efficiency, and adopt clean energy and flexibility products

a. Scale existing EE, DR and heat pump rebate and incentive programs

b. Scale existing EV programs

c. Scale flexible connection offerings for solar and energy storage

d. Test and enable flexible connection offering for EVs

e. Introduce time-varying rates (TVR) through separate proceeding

2. Provide new opportunities for customers and 3rd parties to earn money for providing local grid services as NWA solutions

a. Offer new, locational BTM EE, DR, and EV managed charging incentives to residential and C&I customers for reducing load during local feeder- or substation-level peak times ("bonus kickers" funded separately from existing Connected Solutions and EV managed charging system- wide program incentives)

b. Procure incremental contracted flexibility through local, technology-agnostic, flexibility market auctions to contract with a broader range of potential flexibility service providers, including (but not limited to) standalone DER who would not be eligible to participate in the locational incentive offerings described above in (a)

c. Partner with an all-electric new construction project in an area that has hosting capacity and peak load constraints to demo DERMS integration and control that can optimize load and generation in line with the local need

d. Pilot a no-cost energy storage offering to income-eligible customers in exchange for using the ESS to address local grid constraints

3. Address resiliency issues for EJ communities

a. Deploy company-owned solar and energy storage projects in EJ communities that can provide community resiliency

To provide a more comprehensive view of what the Company is doing to accelerate clean energy solutions for its customers, the following sections include programs the Company is proposing to invest in through the Future Grid Plan, as well as brief descriptions of adjacent programs that are or will be funded via other regulatory proceedings. Exhibit 6.30 below summarizes the proposed clean energy customer solutions the Company plans to implement over the 5- and 10-year investment periods.

Exhibit 6.30: Clean Energy Customer Solutions and Regulatory Pathway

Category	Customer Offerings	Segment	Status	Regulatory Pathway
1) Help customers improve energy efficiency and adopt clean energy and flexibility products	EE incentives, heat pump incentives, and current DR programs	Res, IE, C&I, Agg	Scale	Three-Year Energy Efficiency Plans
	EV make-ready and managed charging programs	Res, EJC, C&I, IE	Scale	EV Phase III (through 2026), ESMP (2027-2029)
	Flex Connections – Solar & Storage	C&I, Dev	Scale	GridMod (pilot), ESMP (scale)
	Flex Connections – EVs	C&I, Dev	New	ESMP
	Time-Varying Rates (TVR)	Res, C&I	New	Future docket
2) Provide new opportunities for customers and 3rd parties to earn money for providing local grid services as NWA solutions	Local EE / DR incentives as VPPs	Res, C&I, Agg	New	ESMP
	Local Flex Market VPPs	Dev	New	ESMP
	All-Electric New Construction Demo	C&I	New	ESMP
	Income-Eligible Energy Storage VPP Offering	IE	New	ESMP
3) Address resiliency issues for EJ communities	Resilient Neighborhoods Program	EJC	New	Future filing

ID	Segment
Res	Residential
EJC	Residential EJC
IE	Income Eligible
C&I	Commercial & Industrial
Dev	Developer
Agg	Aggregator

Exhibit 6.31 below shows the timeline of how the Company proposes to deliver these solutions over the duration of this Plan:

Exhibit 6.31: ESMP Customer Offerings Planned Timeline

	Customer Offerings	2025	2026	2027	2028	2029
(1)	EE incentives, heat pump incentives, and current DR programs	Three-Year Energy Efficiency Plan			Three-Year Energy Efficiency Plan	
	EV make-ready and managed charging programs	EV Phase III		Continue through ESMP		
	Flex Connections – Solar & Storage	Expand offering from demo to product				
	Flex Connections – EVs	Program Design	Built, test and pilot for customers in priority locations			
	Time-Varying Rates (TVR)[1]	Rate design planning through separate proceeding				
(2)	Local EE / DR incentives as VPPs	Initial local incentives for NWAs		Standardized incentives for NWAs		
	Local Flexibility Market VPPs	Initial local flexibility RFPs for NWAs		Improved locational flexibility auctions for NWAs		
	All-Electric New Construction Demo	Launch demo		Explore standardized product		
	Income-Eligible Energy Storage VPP Offering	Supplement DOE Generac grant with battery-specific offering in priority location				
(3)	Resilient Neighborhoods	Initial sites		Scaled program		

Legend: Non-ESMP filing/docket; Proposed in ESMP

Exhibit 6.32 below shows how these solutions help deliver on Future Grid Plan objectives:

Exhibit 6.32: Proposed Customer Programs Deliver on ESMP Objectives

Customer Offerings	Funding Pathway	Improve grid reliability, communications, and resiliency	Enable increased, timely adoption of renewable energy and DERs	Promote energy storage and electrification technologies for decarbonization	Prepare for climate-driven impacts on T&D systems	Accommodate transportation and building electrification	Minimize or mitigate impacts on ratepayers
EE incentives, heat pump incentives, and current DR programs	Three-Year Energy Efficiency Plans	✓		✓			✓
EV make-ready and managed charging programs	EV Phase III (through 2026), ESMP (2027-2029)	✓	✓	✓		✓	✓
Flex Connections – Solar & Storage	GridMod (pilot), ESMP (scale)		✓	✓			
Flex Connections – EVs	ESMP		✓	✓		✓	
Time-Varying Rates (TVR)	Future docket		✓	✓		✓	✓
Local EE / DR incentives as VPPs	ESMP	✓	✓	✓		✓	✓
Local Flex Market VPPs	ESMP	✓	✓	✓		✓	✓
All-Electric New Construction Demo	ESMP	✓	✓	✓		✓	✓
Income-Eligible Energy Storage VPP Offering	ESMP	✓	✓	✓	✓		✓
Resilient Neighborhoods Program	Future filing	✓	✓	✓	✓		

6.11.1 Help Customers Improve their Energy Efficiency and Adopt Clean Energy and Flexibility Products

The Company is implementing several rebate and incentive programs that help reduce the costs of purchasing and installing DER,[16] programs that reward customers for flexing energy usage down during system-wide peaks, as well as new programs to offer alternative, lower cost, and faster interconnection via flexible connections. As described in Section 6.3, the Company is also investing in customer-facing technology improvements that will enhance the customer experience of connecting new generation or load.

6.11.1.1 Energy Efficiency, Demand Response, and Heat Pump Adoption Incentives

The incentives described in this Section were approved via the Company's Three-Year Plan and are included to provide a holistic view.

The Company delivers critically important clean energy programs for customers through approved filings, including EE, DR, and heat pumps. Those programs include incentives to customers to install measures that improve the energy efficiency of their homes (residential) or businesses (C&I), installation incentives for partially or fully displacing a customer's heat system with EHPs (both residential and C&I customers), and installation incentives for custom C&I projects that are too large or too unique for a prescriptive solution.

[16] Note that electric utilities in MA do not currently provide direct incentives (via direct payment, tax credits, etc.) for solar, battery storage, and EVs; those are instead provided by state and federal entities.

The Company also runs a portfolio of actively controlled DER measures together with the other Energy Efficiency Program Administrators through its Connected Solutions program, funding for which is approved through the Company's Three-Year Plans. That program offers incentives to residential, commercial, and industrial customers to reduce load when the grid is at peak loading. As of the end of summer 2023, the Company had just over 100 MW of peak load capacity enrolled in Connected Solutions.

Connected Solutions Measure	Current Incentive Structure
Direct Load Control Thermostats (primarily residential)	$50 per thermostat for enrolling and $20 per thermostat per year for staying enrolled.
Direct Load Control Battery Storage Systems (primarily residential)	Customers are eligible to apply for a Heat Loan for the cost of the battery storage system and earn $275/kW performed per year.
Targeted Dispatch (~5 events per year) – C&I Customers	Customers earn $35/kW-performed per year.
Daily Dispatch (~50 events per year) - C&I Customers	Customers earn $200/kW-performed per year.

When called collectively for peak load events, these assets effectively reduce the capacity needed on the transmission and distribution systems, provide DR induced price effects (DRIPE), and increase system reliability.

The federal Department of Energy (DOE) recently selected Generac for a $50M Grid Resilience and Innovation Partnerships (GRIP) grant.[17] National Grid and the other Program Administrators are working with Generac now on finalizing the grant approval process and look forward to working with the DOE and Generac to provide approximately 2,000 zero-upfront-cost heat pumps, thermostats, and batteries to income-eligible customers and to enroll these customers into Connected Solutions, where they will earn annual pay-for-performance incentives. Other potential use cases for the batteries under consideration include reducing forecasted winter morning peaks at the ISO-NE level and using them to soak up excess solar production during light load conditions, thereby helping to mitigate reverse power flow.

The portfolio of energy efficiency programs in the Commonwealth, which are administered and delivered by the Company and other Program Administrators, are nation-leading programs that are not only cost-effective for customers, but also drive financial savings and other benefits to the residents and businesses of the Commonwealth. Together, these programs address several of the Future Grid Plan objectives and provide benefits such as bill savings for participating customers and broader social benefits (such as comfort, reliability, and cleaner air) for the Company's overall customer base. Since 2010, the Company's EE, DR and heat pump programs have delivered $14.6B of benefits.

The programs continuously evolve to best serve the needs of the Commonwealth and have continuously adapted to best serve the Commonwealth. The Company will engage and prepare for new opportunities with customers through its next Three-Year Plan (2025-2027), focusing on heating electrification, decarbonization measures, and integration with the forthcoming AMI meters.

[17] "Accelerating Building Thermal Electrification While Managing System Impacts." https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2039_Generac%20Grid%20Services_v4_RELEASE_508.pdf

6.11.1.2 Clean Transportation Programs

The programs described are approved through 2026 via the Company's EV Phase III program; the Company proposes to scale and expand these programs through this Plan in 2027 through 2029.

Through EV Phase III, the Company offers programs for residential, multi-unit-dwelling, public and workplace, and fleet customers to encourage EV adoption and EV charging installations, as well as an EV Off-Peak Charging Rebate program that provides rebates to residential and commercial customers who charge their EVs during off-peak hours. These programs are currently funded through 2026 via the Company's EV Phase II and Phase III programs.

Beyond 2026 (the current end date for EV Phase III), the Company has forecasted an extension and expansion of these programs based on the forecasted increase in EVs in operation. Just as EV Phase III was sized to help the Commonwealth meet its targets for EVs in operation, the Future Grid Plan includes costs to run similar programs that scale up to meet even higher targets for EVs in operation during 2027 through 2029.

In practice, the specific customer offerings will need to be adjusted to ensure the Company supports customers with transportation electrification with the programs they need at fair levels of incentives, but with EV Phase III launching in 2023, the Company will learn from its current set of offerings, shifting market dynamics, and state policy before proposing new products and services. The customer program costs are estimated from costs for approved Phase III programs and forecasted increases in EV adoption.

The Company also (a) enables Vehicle-to-Grid participation (discharging energy from the vehicle's battery back to the grid), including from school buses, via the Connected Solutions program, and (b) has filed with the Department an EV-only Time of Use rate for residential customers.

6.11.1.3 Flexible Connections for Solar and Energy Storage

These programs are described to provide a holistic view.

The Company began developing flexible interconnections capabilities as part of its approved Grid Modernization Plan (GMP) in 2022, with the aim of enabling DG projects in appropriate areas of the Company's distribution system to interconnect to avoid significant distribution system upgrades. Through the GMP, the Company started with an Active Resource Integration (ARI) solar demonstration pilot. In 2023, the Company launched a flexible interconnection pilot for energy storage systems.

The solar and ESS flexible connections pilots address a key challenge in the DG interconnection process – long and costly lead times that arise when the study of unconstrained generation of a new solar and/or energy storage project triggers the need for a system upgrade on a given circuit. Through a flexible connection offering, the DG project would be able to interconnect more quickly, without having to pay a costly upgrade, in exchange for allowing the Company to actively manage the facility's operations during periods when the system is unable to handle excessive generation or load.

As discussed above (Section 6.3.2.1.2), in this Plan the Company proposes to enhance its DERMS capabilities to integrate flexible connections projects into its hosting capacity maps, and to optimize interconnection study tools to allow for the rapid study of flexible connections options for future projects.

6.11.1.4 Flexible Connections for EV Fleets

This is a new incremental program proposed in the Plan.

Through this Plan, the Company proposes to accelerate EV fleet adoption by testing and enabling a flexible connections option for EV fleets.

The timelines required to build out infrastructure for large EV charging projects can be substantial, taking two to five years or more in some situations. This is significantly slower than both customer expectations and commercial vehicle procurement timelines, which can often be less than one year. This presents a significant challenge to fleet operators to meet zero-emission vehicle (ZEV) goals because the lead times for utility system upgrades prevent them from fully satisfying their demand. Charging operators of all types, including large fleet depots, mixed-use or multiple customer depots, and highway charging sites could be impacted by delays in project timelines.

To address the challenge of long lead times for distribution system upgrades, the Company proposes to offer commercial and fleet EV charging customers with an alternative EV connection service option in lieu of or as an interim mitigation while waiting for distribution system upgrades, called Flexible Connections for EVs. This proposal would facilitate meeting the Commonwealth's climate targets.

Flexible Connections for EVs would allow EV charging sites, under specific conditions, to charge their vehicles prior to the completion of construction of system upgrades by temporarily having the Company actively manage the facility within the capabilities of the existing grid infrastructure. Typical customer connections are limited by the peak demand on existing grid assets, but this solution can allow charging operators to utilize the existing distribution lines throughout the year, when significantly more capacity is available. This allows charging operators to install substantially more charging capacity while increasing the utilization of existing grid assets. Flexible Connections for EVs potentially could reduce the in-service dates of these MW-scale EV projects by two to four years. Discussion with commercial fleet customers to date has been positive.

This solution can also be beneficial to (1) the operation of the grid, since it increases the utilization of existing assets, and (2) to ratepayers, as it may defer distribution system (and transmission system) upgrades and their associated costs.

The Company proposes to build, test, and pilot the technology with EV charging customers in select locations during the term of the Plan (2025 through 2029). In the second ESMP (2030 through 2034), the Company will propose focusing on scaling the solution to additional EV customers across broader geographies as electric vehicle adoption continues to increase.

6.11.1.5 Time-Varying Rates

Included to provide a holistic view. To be proposed in separate, future docket.

Over the course of the Company's 5- and 10-year ESMP period, the Company intends to test, deploy, and scale new electricity rate design options that provide incentives to customers to shift their energy consumption to help reduce the overall costs of the energy transition.

Given the broad scope of issues that the Department may determine warrant consideration regarding the ESMPs, the Company, along with the other EDCs, proposes to defer consideration of potential rate redesign options, including time-varying rates, to a generic proceeding, or other dockets currently open to consider such options (e.g. with respect to electric vehicle time-of-use rates, D.P.U. 23-84 and D.P.U. 23-85).

The Company and other EDCs are proposing to explore changes to rate design options, including time-varying rates, in a generic proceeding or other appropriate dockets, which may result in rate design changes to be implemented prior to the next ESMP or at the time of the next ESMP cycle.

Please see Section 9.6.2 and Section 9.6.3 for more detail on the Company's longer-term perspective on rate design.

6.11.2 Provide new opportunities for customers and third parties to earn money for providing local grid services as NWA solutions

As described above, the Company administers several demand-side customer programs today that compensate customers for helping to reduce peak load across the electric system. These programs include nation-leading and well-established energy efficiency and demand-response programs and relatively nascent EV-managed charging programs. The Company accounts for the load-reducing impact of EE and DR programs in the electric load forecasts that it uses to plan necessary infrastructure upgrades. This has helped offset investment because the Company already relies upon significant load reductions from those programs.[18]

As the Company enters a period of substantial growth in both expected customer load as well as deployment of controllable DER and new grid modernization technologies, the Company is reimagining the art of the possible with how flexibility can be used to help manage constraints on the network beyond the system-wide peak load reduction programs. The proposed new offerings described below would address local, feeder- or substation-level needs in the form of Bridge-to-wires and asset deferral NWA solutions to address needs described in Sections 6.4-6.10, and would be funded leveraging the new regulatory frameworks for NWAs proposed in Section 6.4.2.5.

6.11.2.1 Local EE / DR / EV Managed Charging Incentives as VPPs

These programs are new incremental programs proposed in the Plan.

As part of its portfolio approach to addressing NWA areas identified in Section 6.5.2 through Section 6.10.2, the Company proposes to offer new incentives to customers to help reduce peak load (either via reducing onsite load or increasing generation) to alleviate capacity constraints during local feeder- or substation-level peaks. Eligible customers and technologies for these incentives would be the same as those eligible for EE rebates, Connected Solutions DR incentives, and managed EV charging rebates today.

The Company plans to conduct further analysis of the specific NWA needs to determine the appropriate level of incentives based on the relevant grid needs at each location. It also recognizes that it will be important to test the market to determine whether the initial values enable sufficient customer compensation to drive a sufficient volume of participation to address the need. The Company is also committed to working with MassCEC, the other EDCs, and other stakeholders via the Grid Services Study (Section 6.11.2.5) to help inform the level of incentive to be offered to customers in those prioritized locations.

[18] The Company's EE programs have reduced system peak load by a cumulative total of approximately 800MW while its DR Connected Solutions Program is now providing over 100 MW of peak reduction capacity.

From a program design perspective, the Company would continue to prioritize customer choice as it does with its current DR and EV managed charging programs by enabling customers to opt out of events. While these assets are not fully dispatchable and under the Company's control, the Company has seven years of data on reliability of performance during event calls through its ConnectedSolutions program. To the degree that these assets would need to provide a higher degree of reliability for addressing distribution-level NWA needs, the Company would plan to "over-enroll" customers to ensure sufficient performance – with the expectation that the required buffer would decrease over time as confidence in the new offerings builds.

6.11.2.2 Local Flexibility Market VPPs

This is a new program proposed in the Plan.

The Company recognizes that enhanced programmatic EE / DR / EV managed charging incentives for behind-the-meter customers may not drive sufficient peak load reduction to meet full Bridge-to-Wires or asset deferral planning needs in terms of timing or capacity. It also recognizes that it is important to test and evolve novel approaches to engaging the market for locational grid services to most efficiently operate and manage the grid longer term.

As a result, the Company proposes to supplement the programmatic incentives described above by procuring additional load flexibility through local, technology-agnostic, flexibility market auctions. The Company would contract with a broader range of potential flexibility service providers, including (but not limited to) standalone DER (e.g., energy storage) who would not be eligible to participate in some of the behind the meter (BTM)-only opportunities described above. The Company may require direct control of DERs awarded contracts to ensure reliability and performance.

First, the Company will work to establish a market platform that will create clear visibility and a registry of potential load and generation flexibility on the network, by area – giving a better view into the DER potential to address Bridge-to-Wires needs. For those needs, the Company will test the ability of the marketplace to run local auctions for flexibility services to procure, for instance, "x" MW, "y" MWh of flexibility, and "z" times per year for a given location. Each competition posted on the market platform would provide a pricing signal to clearly present the value proposition to market participants. Furthermore, each competition will clearly state the expected times of dispatches, the length of each dispatch, the frequency of dispatches and MW requirement. Market participants would have the option to bid for all or part of the needs presented in a given competition.

To inform this offering, the Company will look to expand upon learnings and best practices from its NWA and Auto-DLM [19] market platform pilot in New York, learnings from its UK flexibility market via National Grid Electricity Distribution (NGED), and leverage results from the Grid Services Study with MassCEC. The Company also commits to working with stakeholders on establishing a market design framework, including entry requirements (i.e., minimum capacity, metering, availability, response time, performance commitment) and structuring of standardized commercial agreements.

[19] https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/auto-dlm_-brochure_final.pdf

6.11.2.3 All-Electric New Construction Demonstration

These programs are new programs proposed in the Plan.

As the Company prepares for both the peak load impacts of EV and heat pump growth and the hosting capacity impacts of continued growth in solar and energy storage interconnection requests in constrained areas, it is considering new and innovative ways to alleviate those issues.

The Company proposes a new demonstration project in this Plan to partner directly with an all-electric multifamily or large C&I new construction project (with solar, energy storage, EV charging, heat pumps, other DER and/or smart devices controlled by building management systems) in a constrained, Bridge-to-Wires location to utilize DERMS technology solutions for greater Company control of customer load and generation. The Company would provide the customer financial incentives in exchange for operating their integrated load and generation assets in ways that address both locational hosting capacity and peak loading constraints.

Operationally, during local peak loading windows, signals would be sent to curtail load, in part by limiting battery or EV charging from the grid, and by increasing export to the grid. Conversely, during periods when feeder- and substation-level load is low, and intermittent generation is high, signals would be sent to increase on-site load (e.g., via battery charging) to enable additional hosting capacity and renewable generation on the grid.

The Company intends to proactively reach out and partner with a customer who has recently constructed high-performance all-electric buildings with existing on-site DER or a developer of a similar new construction project, willing to give the Company partial operational control to operate their BTM DER flexibly and automatically in ways that help alleviate localized grid constraints, while minimizing occupant impacts. The customer would need to be sited in a Bridge-to-Wires location that also has hosting capacity constraints. The Company has identified a preliminary list of over two dozen potential candidates on constrained feeders, and will engage in customer outreach to recruit potential partners and determine suitability for participation. The Company will generate learnings on reliability improvements, cost-effectiveness, emissions reductions, and customer and tenant experience to potentially scale in the 2030-2034 time period.

6.11.2.4 Income-Eligible Battery VPP Offering

These programs are net new incremental programs proposed in this Plan.

The Company proposes a supplemental offering that builds on the DOE Generac grant described in section 6.11.1.1 to a) support bringing additional income-eligible customers along in the clean energy transition, and b) aggregate those customer assets as part of a Bridge to Wires NWA solution. Through this income-eligible battery VPP offering, the Company would offer an energy storage system (ESS) at no upfront cost to a select group of income-eligible customers in a Bridge-to-Wires NWA location. Customers would benefit from increased resiliency via battery backup power. The Company would, in exchange for offering the batteries at no upfront cost, retain control of the ESS and use them as an NWA to help address the locational peak load constraint. The Company will generate learnings on reliability improvements, cost-effectiveness, and customer experience to potentially scale in the 2030-2034 period.

This stand-alone energy storage offering is distinct from the support that the Company will provide to Generac through its DOE grant, which will specifically target customers eligible for the Company's heat pump incentives, and focus on learning how usage of smart thermostats, heat pumps, and batteries can provide demand flexibility around winter peaks. This offering will enable the Company to engage additional segments of income-eligible electric customers, including those with natural gas heating who are not prime candidates for the heat pump incentives that are part of the Generac offering.

The Company would manage 80% of each customer's energy storage capacity and aggregate those resources as a VPP to alleviate localized grid constraint events, while leaving 20% of each customer's capacity for short-term resiliency during unexpected outages. Batteries would be fully charged ahead of forecasted storms to provide a longer period of uninterrupted service in the event of a storm-related outage.

Where possible, the Company will focus on outage-prone and constrained feeders within EJCs. Through use of reported outage metrics, the Company has identified several promising locations where feeders prone to outages located within an EJC overlap areas where capacity for grid services is needed to reduce reliability risks.

6.11.2.5 Grid Services Study

This study is included to provide a holistic view.

The Company is planning to work with the other EDCs and MassCEC on a Grid Services Study in parallel with this ESMP process. The intent is for the Study to occur imminently in 2024, such that the results of the study would directly inform the Company's locational grid services offerings to address as soon as 2025. The scope of the study will be to develop a statewide DER compensation framework that identifies the value of DER providing locational grid services to the utility based on characteristics such as technology, level of availability, and level of direct utility visibility and control. The study would also include provisions for the added value DER can provide in EJC. The EDCs are proposing to conduct the study collaboratively with input from stakeholders. Building upon learnings from the Grid Services Study, the Company proposes a second study together with the other EDCs to develop recommendations for a more dynamic locational value compensation framework. The study would be completed in the second half of the 2025-2029 term and would be based on results and lessons learned from implementation of the Grid Services Compensation Fund. The result of the Transactional Energy Study would inform proposals in the Company's 2030-2034 ESMP.

6.11.3 Address resiliency issues for environmental justice communities and income-eligible customers

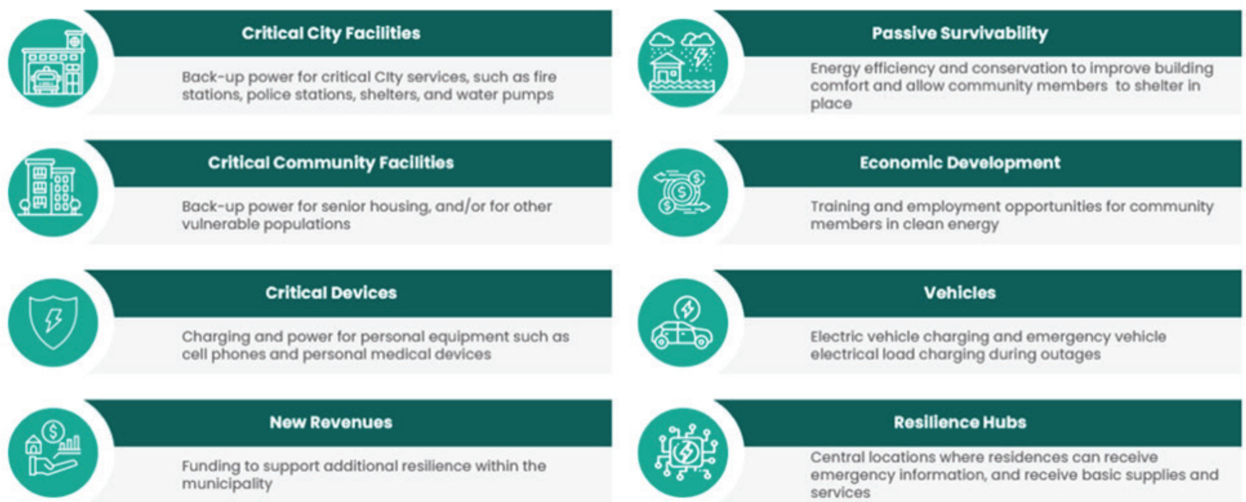
6.11.3.1 Resilient Neighborhoods Program

Described for holistic view. To be proposed in separate, future docket.

Section 77 of MA Bill S.9 - An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy – enables electric and gas distribution companies to construct, own, and operate solar generation facilities paired, where feasible, with energy storage facilities, that contribute to the climate change resiliency of the host municipality and mitigate peak energy demand, with a strong emphasis on supporting EJCs. Since the passage of that bill, the Company has been working to identify the best opportunities to site solar and storage projects that will provide resiliency and climate adaptation benefits to EJCs within the Company's service territory in the Commonwealth and has been doing so under the banner of the Resilient Neighborhoods Program.

As a foundational effort for this program, the Company worked in partnership with the National Renewable Energy Lab (NREL) to identify different types of Resiliency Benefits that could be offered to municipalities through a locally sited, utility-owned solar project. That work identified eight benefits categories, listed below in Exhibit 6.33, to be considered when engaging with municipalities on how to best provide climate adaptation and resiliency benefits through each utility-owned project.

Exhibit 6.33: Types of Climate Adaptation and Resiliency Benefits to Consider when Engaging Municipalities on Utility-Owned Projects



Source: Converge Strategies

Section 77 also requires "affirmation of support by a municipality" to be presented in any petition for pre-approval of cost recovery for such solar facilities. As such, the Company is directly engaging with Town Administrators or City Mayors to get their feedback and interest in the opportunity. After initial meetings, if interested, workshops are held with key department leads from the municipalities with the objective of developing a shared understanding of the project opportunity and identifying resiliency benefits that the project could create for the community. To date, each workshop has had participation of 6 to up to 15 individuals including police and fire chiefs, conservation agents, planning and development directors, and other municipal officials relevant to the proposed opportunity. These engagements are crucial to gain feedback on and support for the program prior to developing and submitting a regulatory filing for Department review. At present, the Company expects to file for its first tranche of Resilient Neighborhoods Program projects by summer of 2024, dependent upon any Department ruling on the projects already filed by Eversource that might impact this timeline.

The Resilient Neighborhood Program will help build grid and community resiliency by providing an increased ability to respond to, withstand, and recover from adverse situations from climate change. It will also result in the integration of new distributed renewable energy projects in the form of solar and storage facilities that will help to achieve the Commonwealth's decarbonization goals. Further, the program will prioritize projects in EJCs.

Projects that are sited in areas of local grid constraint also present an opportunity to stack benefits. Depending on how the projects are determined to be operated, in partnership with each municipality, with a primary objective to maximize community resiliency, they could also provide locational grid benefits, such as battery storage discharge during peak loading conditions.

6.12 National Grid Supporting Investments

The Company proposes investments necessary to support delivery of the programs proposed in the Plan and to keep pace with delivery of the Commonwealth's 2050 Net Zero goals as outlined in the CECP. These supporting investments reflecting that the Company must implement in future years to operate and maintain the system and deliver clean energy programs for customers.

Larger warehouse space to support incremental workplan

The expected investments between now and 2050 will require a scale of build not seen since the 1980s. The Company will need to have the space and capabilities for managing inventory levels that are 2X greater than the Company's current capacity in Massachusetts based on the Company's anticipated work plans. The Company must also support holding larger quantities of materials over longer periods due to supply chain and manufacturing lead-time challenges. The warehousing space will ensure we can store, manage and provision the additional materials necessary for the network investments.

Fleet charging infrastructure at Company facilities

The Company operates one of the largest fleets of light-duty and medium- and heavy-duty vehicles (MHDV) in the Commonwealth. Incremental Fleet EV charging for medium- and heavy-duty vehicles requires DC fast charging (DCFC) facilities. The Company needs to develop EV charging facilities infrastructure ahead of the lease and/or purchase and operation of medium and heavy-duty electric vehicles (MHDEV).

The Charger-to-Vehicle ratio required to maintain daily operations activities are one Level 2 charger per light- and medium-duty vehicle and one DC fast charger per 10 light- and medium-duty vehicles to allow for quick charging at strategically placed hubs during the working day. Heavy-duty vehicles will require one DC Fast Charger per vehicle.

The Company's proposal also includes costs to support a fleet telematics system. A fleet telematics system provides detailed and accurate location and usage data that the Company can use to make decisions to support the planning and execution of charging infrastructure and electric vehicles.

Proactive investments in Company charging infrastructure will enable an efficient and timely transition of the Company's MHDEV fleet in support of the broader fleet transitions over the next ten years.

Electric Vehicle Leasing for Company Fleet Transition

The Company's proposal includes the lease costs associated with accelerating fleet transition to electric vehicles for medium- and heavy-duty vehicles. The Commonwealth's clean transportation regulations require the Company to transition its MHDV fleet. The projected pace of electric vehicle adoption underlying the estimates is relatively modest over the Plan term, and assumes a relatively slow ramp up with larger adoption expected from 2035 and beyond.

Garage Equipment to Support Blue Sky EV’s & Emergency Staging Site Charging for Company EV Fleet

Transitioning to an electric fleet requires that the Company be prepared for the unexpected, including the ability to maintain EV fleet operations in extreme scenarios. The Company’s proposal includes costs to implement mobile charging units to support electric vehicles that do not return to a Company yard at the end of the shift. Not all Company vehicles or pieces of equipment return to the yard at end of the shift. As the Company continues to transition to electrified equipment, it needs to ensure the equipment can be charged without having to return to an operating yard. This would enable remote site charging for equipment that is left on a construction site for an extended duration.

The Company’s proposal also includes associated costs for garage maintenance staff to address state of charge issues or breakdowns in the field, including one portable battery trailer per garage to support garage maintenance activities, such as breakdown roadside assistance or assistance in a yard.

Section 7

5-year Electric Sector Modernization Plan

This section summarizes the overall costs and benefits of the Future Grid Plan and explains the challenges and risks to delivering against the Plan.

Key Take-Aways

- The Future Grid Plan's proposed investments to meet the Commonwealth's clean energy and climate goals depend on the foundation of the Company's base capital investment plan, in-flight investments already approved by the Department (such as Grid Modernization and AMI) and pending proposed Capital Investment Projects (CIPs).
- The Future Grid Plan demonstrates the need for approximately $2.5 billion of proposed investment over 2025-2029 to meet customer needs and build a network that supports the Commonwealth's net zero transition.
- The Company's robust Plan includes network investments, platform investments, customer investments and programs, and EV programs. The Plan also proposes new Capital Investment Projects (CIPs) to enable DER interconnections.
- The Future Grid Plan delivers significant benefits to customers and communities across a range of areas, including safety, facilitation of the electrification of buildings and transport, GHG emission reductions and Distributed Energy Resource integration.
- To make the needed proposed investments to achieve the Commonwealth's net zero goals, the Company must be able to fund its proposed investments without the risk of regulatory lag for making the right investments.
- To ensure that the Company can deliver on the objectives and magnitude of work outlined in this Plan, the Company will continue its focus on identifying and addressing key risks to the delivery of the plan, including permitting, supply chain and workforce challenges.
- While the proposed investments in the Company's Plan were engineered to meet the Commonwealth's CECP targets, a key goal of the Company's proposed Plan is to drive the investments and their associated benefits in a more equitable fashion going forward. Two primary actions that will be driven by the Company to break down historical barriers and facilitate benefit realization in a more equitable fashion include: (a) providing offerings and programs for EJCs and LMI customers that will allow them to more readily participate in the clean energy transition and lower their bills and (b) establishing formal, accountable frameworks for stakeholder engagement and outreach such that customers are aware of and can take advantage of these programs.

7.0 5-year Electric Sector Modernization Plan

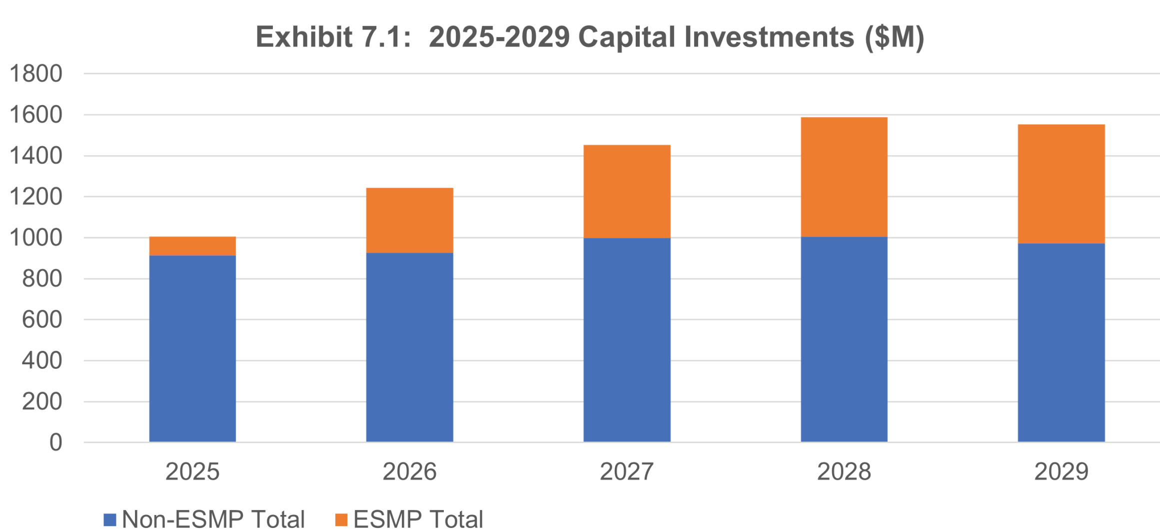
In the distribution Base Rate Case (BRC) that was filed in November 2023, the Company proposed an Infrastructure, Safety, Reliability and Electrification (ISRE) Provision that if approved by the Department will serve as the mechanism to recover the costs of the Company's ESMP spending plan. The ISRE cost recovery mechanism will permit the Company to make the needed core and incremental investments as described in the distribution BRC and this Future Grid Plan (ESMP) to meet customers' evolving needs and achieve the Commonwealth's net zero goals. This proposed cost recovery mechanism is similar to what is already in place for the Company's incremental Grid Mod and AMI investments and will permit the timely recovery of any O&M and in-service capital investment up to a cap, subject to a prudency review in the year following the spend.

7.1 Investment Summary 5-year Chart

The five-year investment summaries below provide a comprehensive view of all active, pending, and proposed investments in alignment with overall public policy goals and customer needs. Of this total five-year investment, the Company's proposed Future Grid Plan investments account for approximately $2.5 billion. To put the ESMP in context, Exhibit 7.1 shows the ESMP proposed capital investments relative to the Company's planned non-ESMP capital investments. Exhibit 7.2 breaks down the ESMP capital investment by category over time, while Exhibit 7.3 does the same for non-ESMP investment. Finally, Exhibit 7.4 provides the annual total capital investment across the variety of categories identified for ESMP and non-ESMP investment.

The ESMP proposes investments at a level that would support the Commonwealth's clean energy and climate goals and meet customers' evolving needs. If necessary, the Company would revisit the investment plan to align with Department decisions on the Future Grid Plan and the Company's BRC.[1]

Exhibit 7.1: Non-ESMP vs. ESMP 2025-2029 Capital Investments ($M)



[1] D.P.U. 23-150.

Exhibit 7.2: ESMP 2025-2029 Capital Investments ($M)

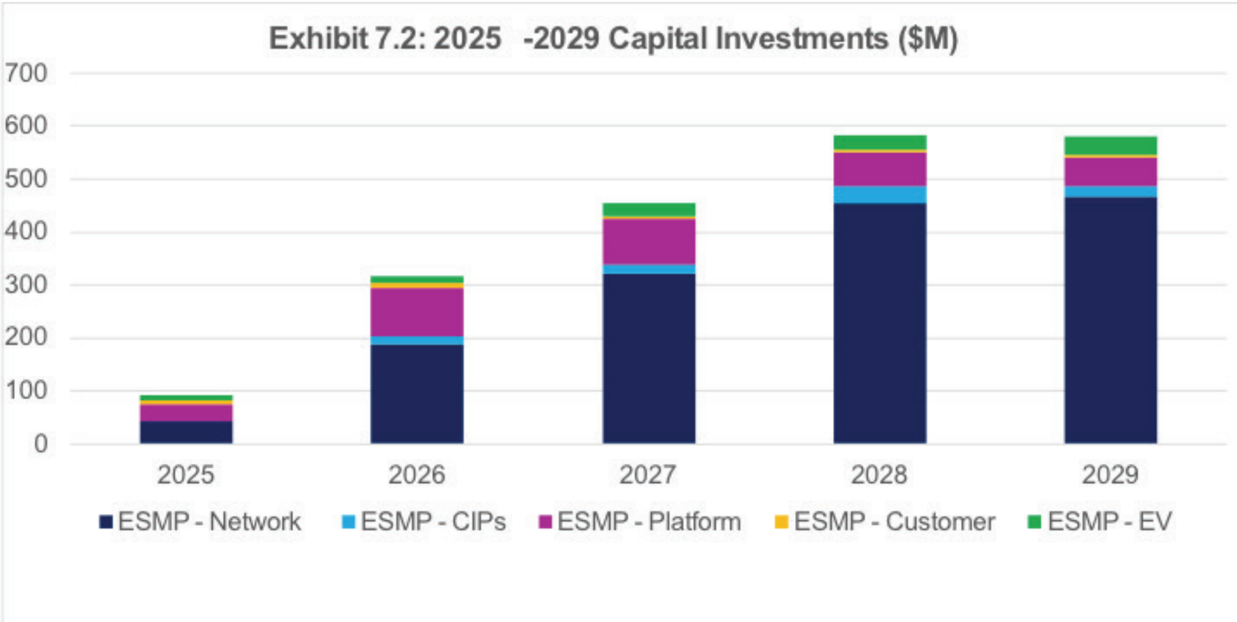


Exhibit 7.4: 2025-2029 Capital Investments ($M)

Categories [2]	Recovery	2025	2026	2027	2028	2029	Total
ESMP: Network	ESMP	54	202	333	466	478	1,533
ESMP: CIPs	Individual projects filed with DPU	(16)	15	18	33	20	70
ESMP: Platform	ESMP	31	91	85	62	54	323
ESMP: Customer	ESMP	7	8	6	5	4	31
ESMP: EV	ESMP	0	0	13	17	24	53
ESMP Subtotal		**77**	**316**	**454**	**583**	**580**	**2,011**

The overall capital investments plan for 2025-2029 as shown in Exhibit 7.4 consists of the categories described in more detail below:

1. **Base Spending – Electric Operations:** Investments included in the Company's baseline long-range plan aimed at ensuring safe and reliable service to customers. The Company builds its baseline capital plan based on five investment drivers.

- **Asset Condition** projects proactively replace, repair, or upgrade assets that are at risk of failing and causing unplanned outages or unsafe conditions. The Company has developed strategies to assess asset conditions to identify specific susceptibilities, or failure modes, and develop alternatives to avoid such failure, which often include replacing assets that demonstrate poor operating conditions that will impair safe and reliable service to customers.
- **System Capacity and Performance** projects are required to ensure that the electric network has sufficient capacity to meet the growing and/or shifting demands of customers. Projects in this category are intended to reduce degradation of equipment service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies. In addition to accommodating load growth, the expenditures in this category are used to install new equipment such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with a service event. This category also includes spending to improve the performance of the network such as the reconfiguration of feeders and the installation of feeder ties. Resiliency spending, such as the hardening of distribution system infrastructure, to make it stronger and better withstand impacts of climate change and other evolving threats is also included within this investment category.
- **Damage/Failure** projects are capital expenditures (CAPEX) required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unplanelined/other deterioration, among other causes.

[2] "ESMP" indicates that the Future Grid Plan also proposes investments in these categories.

- **Customer Requests/Public Requirements** projects are required to respond to or comply with Customer Requests/Public Requirements mandates. This work includes CAPEX required to ensure the contractual obligations of the Company adhere to customer requests and public requirements. These items include new business residential, new business commercial, outdoor lighting, third party attachments, land rights, and public requirements including municipal and customer interconnections.
- **Non-Infrastructure** represents projects addressing Information Technology (IT), fleet, small tools, and property investments in the Company's facilities. The "non-infrastructure" category of investment is for CAPEX that does not fit into one of the foregoing categories, but which is necessary to run the electric system. Examples of work in this category include investments in tools, including field equipment, large tools, security, radio systems, test equipment, etc.

2. **Active regulatory investments:** Capital investments included in the Company's long-range plan funded in existing rates through dedicated mechanisms.

- **AMI** (Advanced Metering Infrastructure) - Authorized investments in D.P.U. 21-81 for new metering infrastructure, communications infrastructure and enabling IT systems, including customer engagement and program management through 2028.
- **EV** - Authorized investments in D.P.U. 21-91 to build out make-ready infrastructure to support EV charging stations.
- **Capital Investment Project (CIP)** – D.P.U. 20-75-B investments proposed in this Plan or pending approval in previous Department proceedings to build out infrastructure required to support DER interconnection.
- **Grid Modernization** – D.P.U. 21-81 authorized investments for 2025 in field devices and Operationl Technology (OT) to support the Commonwealth's established grid modernization objectives.

3. **Future Grid Plan (ESMP):**[3] Investments included in this category are intended to further the Commonwealth's clean energy objectives and support a smarter, stronger, cleaner and more equitable energy future aligned with the goals and objectives of the 2050 CECP. They are incremental to, and build on, the Base Spending and Active Regulatory Investments. For each of the categories, the costs include incremental full-time equivalents (FTEs) required to support the implementation of the proposed investments and programs. Please refer to Section 6 for more detailed descriptions of these proposed investments and programs, as well as their justification. ($2.0B).

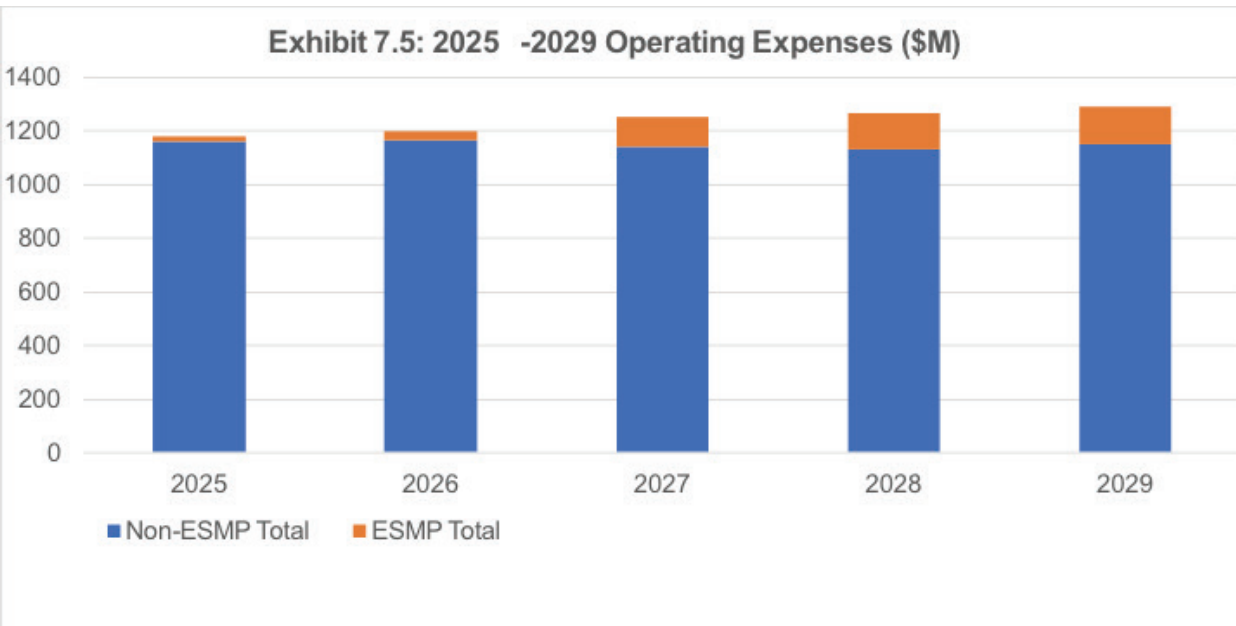
- **Network Investments** – New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology to improve network operations and management ($1.5B).
- **CIPs** – Substation and line upgrades to enable DER interconnections with cost allocation. The Company is not proposing CIPs for approval as part of this ESMP; rather, CIPs are included for informational purposes and completeness. The Company anticipates making additional CIP filings. ($69M).

[3] Extensions of the Company's grid-facing and customer-facing investments, including grid modernization and AMI investments, are included in the five-year investment plan in compliance with the Department's Grid Modernization Phase II Order (Order on New Technologies and Advanced Metering Infrastructure), D.P.U. 21-81-B, page 336. Extensions of EV investments are included in the five-year investment plan in compliance with the Department's Phase III Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal order, D.P.U. 21-91, page 158.

- **Platform Investments** – Technology investments to accelerate and support the transition to a clean energy-heavy grid, including network management technologies (including DERMS), telecommunications, cybersecurity, data management, and new digital products to support asset management, technology, and operations.[4] ($323M).
- **Customer Investments and Programs** – New programs and demonstrations to advance VPPs and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies ($31M).
- **EV Programs** – Continuation of existing EV make-ready and charging infrastructure enablement programs. ($53M).

In addition to the capital investments described above, the Company must spend in future years to operate and maintain the system and deliver clean energy programs for customers. Proposed Future Grid Plan operating expense represents approximately 7% of the total projected five-year operating expenditures.

Exhibit 7.5: Non-ESMP vs. ESMP 2025-2029 Operating Expenses ($M)



[4] Note that many of the platform and some customer investments may be delivered through National Grid's service company entity and subject to suitable cost allocations to the Company. The Future Grid Plan has represented the initial allocated investment in the CAPEX views. Costs incurred through the service company are allocated to benefitting entities and charged to said entities through rental charges.

Exhibit 7.6: ESMP 2025-2029 Operating Expenses ($M)

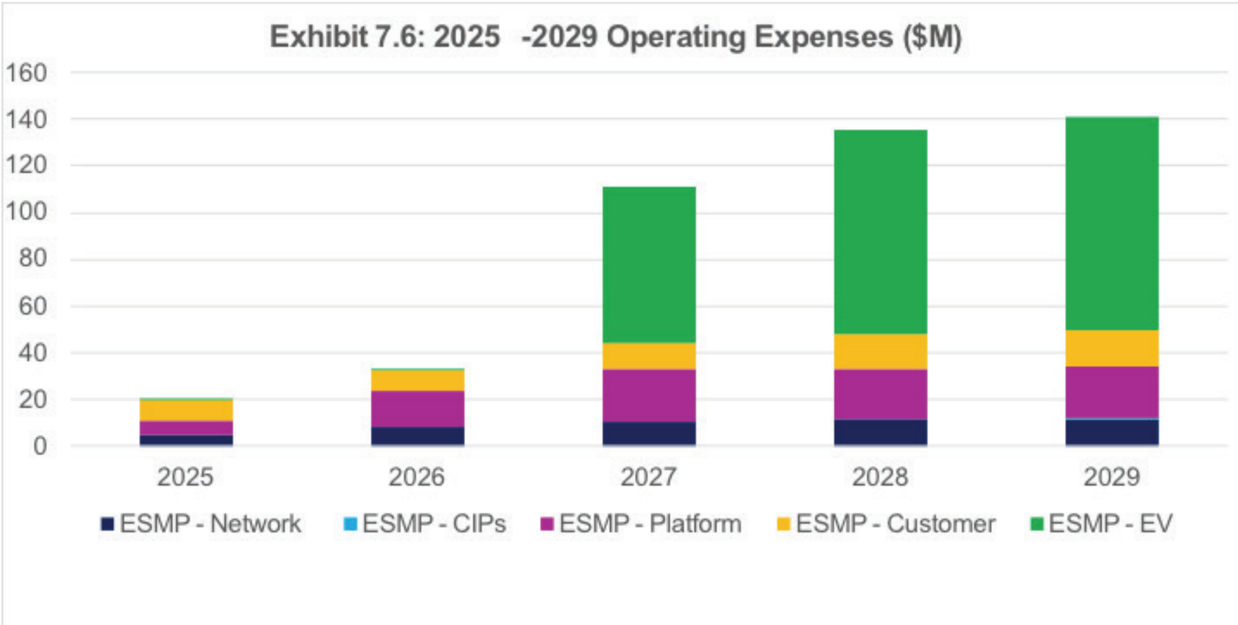


Exhibit 7.8: 2025-2029 Operational Expenses ($M)

Categories	Recovery	2025	2026	2027	2028	2029	Total
ESMP: Network	ESMP	6	10	13	14	14	57
ESMP: CIPs	Individual projects filed with DPU	0	0	0	0	0	1
ESMP: Platform	ESMP	5	13	20	19	20	77
ESMP: Customer	ESMP	10	11	16	16	16	69
ESMP: EV	ESMP	0	0	67	87	92	246
ESMP Subtotal		**21**	**34**	**117**	**137**	**142**	**450**

Operating expenses mirror capital investments (as defined in detail above) and are classified into the following three categories:

1. **Base Spending – Electric Operations:** Investments included in the Company's baseline long-range plan aimed at ensuring safe and reliable service to customers.

2. **Active regulatory investments:** Operational expenses included in the Company's long-range plan funded in existing rates through dedicated mechanisms.

3. **Future Grid Plan (ESMP):** The Company proposes incremental operating expenses for the five categories of CAPEX-related investments described earlier in this section: Network, CIPs, Platform, Customer and EV. Network, CIPs and Platform investments are predominantly composed of capital investments but also contain relatively minor amounts of operational expenses. Customer and EV investments and programs have relatively significant amounts of operating expenses because they include incentive-based programs. For instance, the "customer" line item includes operational expenses associated with grid services compensation fund and the "EV" line item includes operational expenses associated with the EV make-ready program incentives. In addition to the five categories described for the capital investments, the operational expenses include a sixth category of ESMP-related costs for "ESMP program administration." This category includes administrative costs such as ESMP portfolio management and stakeholder engagement. ($450M).

The investments described in the first five years of this Future Grid Plan are necessary to make progress towards the Commonwealth's decarbonization goals. The Company is committed to reducing its own direct GHG emissions as well as delivering an electric network that can enable reduction in the main contributors to GHG emissions today: transportation, energy production, and heating. The Company's Demand Response (DR) and Energy Efficiency (EE) programs will continue to drive GHG reductions, but the Company must now ensure the network has enough capacity and reliability to enable the electrification of transportation and heating and the connection of more DERs. The investments described in this Section enable these GHG reductions and the buildout of capacity to support broader policy objectives and customer adoption needs.

7.1.1 Alternatives to Proposed Investments – Estimates of Impact of Investment Plan Alternatives

The Company completed a comprehensive assessment of the overall network needs considering the system's current state and the needs for future electrification and customer benefit realization. When considering alternatives, the Company prioritized safety and reliability, supporting projected load and capacity needs, and preparing the network for forecasted growth.

The Company needs to act now to deliver the broader capabilities and network capacity needed for the energy transition. Delaying these foundational investments risks not having the network capacity and supporting technology needed to achieve the Commonwealth's GHG reduction goals.

The Company's Future Grid Plan is the result of a robust process that builds on years of work developing investment plans, technology roadmaps, and customer strategies to address customer needs and clean energy goals. The following subsections describe the process undertaken to evaluate major categories of investment alternatives.

Anticipatory Planning and Investment and Affordability

Fundamentally, meeting the Commonwealth's CECP goals will require (1) customers across the Commonwealth to accelerate the adoption of clean, electrified heating and transportation technologies and (2) significant amounts of new renewable and clean energy resources to be connected to the grid at a pace and scale aligned with the Commonwealth's stated milestones. Achieving both requires focus by the Commonwealth, through policy action, and electric distribution companies, through their distribution (and transmission) planning, on six key areas: (1) anticipatory planning and investment; (2) permitting reform; (3) environmental justice; (4) equity; (5) demand flexibility and DERs; and (6) affordability. Two of these areas of focus, (1) anticipatory planning and investment and (2) affordability, are inextricably interrelated, such that the Commonwealth and the distribution companies can and should consider both areas holistically when planning for proactive investments designed to meet the Commonwealth's CECP goals. For example, if customers and clean energy developers cannot connect to the system at a sufficient pace, the Commonwealth's interim targets could be impacted. Similarly, if the costs associated with connecting to and consuming increasing amounts of clean electricity are considered prohibitive, this will impact customer adoption of electrified heating and transportation and the decarbonization of electricity supply. The pace of proposed investments is therefore driven by the need for and expectations of customer adoption and developer needs.

The Company's stakeholder engagement and feedback to date has reinforced this dynamic. The Company has held direct dialogues and meetings in both facilitated forums and one-on-one settings, leveraging multiple and diverse communication channels through earned and paid media platforms, developing facts sheets and videos translated in multiple languages, and building digital tools such as websites and social content to provide all customers access to information about the ESMP process, the Company's plans, and ways to provide input. The Company also met with more than 80 municipalities, 12 business and economic development organizations (including individual members), energy assistance providers, academic institutions, organizations representing generators, renewables, DER providers, EV providers and other technology providers, state officials, housing developers, and members at the EJ Table, which is a statewide coalition formed to inform and support environmental justice legislation and policy in the Commonwealth. In addition, the Company participated in stakeholder meetings as part of the GMAC in October and November 2023.

Feedback from these stakeholder meetings has focused on the following issues:

- The importance of a deliberate and equitable transition, with the need to start meaningful engagement and planning with impacted communities and customers early in the process. This early engagement is needed to ensure that the Company is capturing and addressing concerns and providing agency in siting decisions, coordinating work with municipalities, and identifying avenues for partnership and shared benefits, particularly for those communities that will either continue to host significant energy infrastructure or will need new investment. This includes working with trusted community partners throughout the process. Additionally, several municipalities viewed the transition as an opportunity to meet multiple goals for clean energy and economic development, by leveraging the process to create clean, electric-ready new business zones in their communities.
- The need to maintain an affordable and reliable energy system, with the recognition that affordability and reliability mean different things – and have different implications – depending on customer segment and economic circumstance. The need to focus on the costs of the energy transition to EJCs, more holistically address overall energy burden, and raise enrollment in existing affordability and assistance programs were raised several times. Many stakeholders focused on the need to ensure the system was resilient and able to respond quickly to any event, particularly as the economy becomes more electrified. For businesses for which electricity is a critical input, such as life sciences and biotech, power quality was also top-of-mind.
- The challenges customers and technology providers have today to connect to the Company's system quickly and affordably, and the need to make it easier to do business with us. This issue was particularly acute for housing, commercial real-estate developers, and DER providers. There is a recognition that National Grid is working to shorten and simplify processes and secure the necessary supply chain, but that more needs to be done, particularly as the pace of electrification and clean energy deployment accelerates.
- The benefits of Mass Save and other programs that provide financial and technical support to pursue clean energy and energy efficient solutions, and the need to expand those programs, such as Community First, and make them more tailored and targeted to individual customer segments and circumstances. Many municipalities are concerned about the costs of the energy transition and their ability to participate fully, not only for their own facilities, but also for their constituents.

Over the next five years (2025 through 2029), the Company proposes to invest more than $2 billion to meet the Commonwealth's electric-based approach to meeting its climate and clean energy goals and enable the just transition. As proposed in this Future Grid Plan these proposed investments focus on 1) network investments, 2) CIP's, 3) platform investments, 4) customer investments and programs, and 5) EV programs. These investments have been carefully scoped to meet specific needs based on forecasted demand and identified system capacity and operational challenges.

These network investments include the upgrade and expansion of eight existing substations, the rebuilding of five substations, and the expansion of 14 feeders over the next five years. In addition, by 2034, six existing substations are proposed to be upgraded, 26 substations are proposed to be newly built or rebuilt, and 13 feeders are proposed to be expanded. These proposed investments are driven primarily by adoption of electric transportation and building heating, which, as described in Section 5, are expected to increase the peak load across the Company's network by 8% by 2029 and 26% by 2034 relative to 2022 levels.

In addition to load-growth driven network infrastructure projects, the Company's Plan includes three DER-enablement CIPs to address interconnection group studies. The Capital Investment Projects include four substation upgrades, resulting in 244 MW of additional capacity proposed to be in-service by 2029. While the underlying impetus for these projects is based on group studies related to DER interconnection projects in-queue, this capacity will similarly be multi-use, meaning that it will be able to support the adoption of electric vehicles and heating, as well as future interconnections of new solar and energy storage.

Absent making these system investments in advance of these new peak demand levels, the expected load growth will result in overloads of existing equipment, which would impact the safety and reliability of network operation. Section 6 provides details on the planning process and proposed investments across the Company's network to proactively address these expected overloads and other needs, and Section 7 explains the key factors driving these investment needs, including unacceptable asset condition and reliability performance concerns and the outcomes the Company established for the ESMP to assess each investment – reliable, ready, resilient, flexible, efficient. As described in Section 6.4.2, ESMP investments proposed in the five-year plan are composed of projects triggered based on imminent capacity deficiencies expected in the first five years and then sized based on long term need.

The ESMP investments proposed by the Company and the other EDCs are the first step to defining the scope and scale of what we collectively in the Commonwealth must do over the next five, 10, and 25 years to combat climate change and enable a more electrified future, in a manner that meets the Commonwealth's 2030 and 2050 CECP goals.

The Company's proposed investments will ensure that over the next five years the Company can deliver over 1 GW of capacity to support our customers' adoption of electric transportation and building heating and enable more DER on the system. To achieve these results, the proposed network investments need to be made proactively, not reactively. The Company's proposed investments will realize multiple outcomes for customers and the system, including:

- Enabling over 1 GW of additional capacity by 2030, enough to support an additional 492,000 electric vehicles and 84,000 electric heat pumps;
- Upgrading dozens of feeders to enable the connection of more clean distributed energy resources; and
- Improving local air quality as more cars, buses, and trucks are electrified.

The Company's Future Grid plan can be refined to the extent that the Department supports a different balance between the pace of proactive investments designed to meet the Commonwealth's CECP goals, and overall affordability for customers and others connecting to the system.

The Company's proposed plan recognizes the critical role the electric distribution system will play in the clean energy transition of the next 25 years and is based on a rigorous assessment of both needs and available solutions. The Company believes both the pace and scale of the proposed investments across network investments, CIP's, platform investments, customer investments and programs, and EV programs are both appropriate and necessary to achieve the Commonwealth's 2050 targets and interim mandated milestones and support the associated pace of customer adoption of electrification and DER deployment.

Decisions taken in the near term must ensure that the infrastructure buildout is not undersized and avoid system reliability risks and customer adoption barriers. Being fully cognizant that affordability is a major concern, the Company also reviewed ways in which the pace of some investments could be adjusted and deferred into future investment periods if the balance between affordability and pace of clean energy deployment and electrification shifted. The Company focused its review on the substation and distribution line investments within the network investments catgeory. It did this for two reasons: 1) network investment is the largest category of proposed investment over the next five and 10 years; and 2) the non-infrastructure components of the Plan provide the underlying foundation for network operations and modernization and customer programs that unlock future innovation and deployment of non-wires alternatives, including VPPs.

The framework the Company used to conduct this assessment focused on:

- Minimizing near-term, local network overload risk.
- Prioritizing projects with more enabled hosting capacity.
- Delivering EJC benefits.

The table below provides an example of the impact on enabled capacity across the network of various levels of investment spend. The analysis is underpinned by a preliminary assessment of how the list of network infrastructure investments and associated outcomes would change if the Company were to reduce the pace of its network infrastructure investments based on the affordability considerations described above. The project list is intended to be illustrative to highlight the tradeoff between investment pace to achieve the Commonwealth's interim targets and affordability, though more detailed project-by-project assessment would need to be completed to determine the specific network infrastructure investments and associated project schedule that the Company could pursue in implementing a reduced-pace plan. While a reduced-pace plan would deliver less new network capacity to support electrification demand growth in the near-term, it would still enable the Commonwealth to make meaningful progress against its interim and longer-term climate and clean energy goals.

Exhibit 7.9: Illustrative Network Investment Costs and Enabled Capacity Estimates for a Reduced Pace Plan

Pace: % of ESMP Proposed Network Infrastructure	**2025-2029**		
	Plant-in-Service	CapEx ($)	Enabled Network Capacity (MW)
100%	$1,164	$1,533	815
50%	$601	$692	366

Note: CAPEX values reflect expenditures in the years in which they would be incurred; Costs are for the network investment category. Enabled capacity numbers are based on load-growth driven substation and distribution projects only (i.e., exclude 244 MW of capacity-enabled from ESMP CIPs projects).

The table below shows the ESMP network investment projects with their proposed in-service years versus their in-service years in a scenario where several infrastructure investments are pushed out to a later investment period.

Exhibit 7.10: Illustrative Project List for a Reduced Pace Plan

#	Region	50% Illustrative Project List	Enabled Capacity	ESMP In-service Year	"50% Pace" In-service Year
1	Central	East Webster Feeder Expansion	NA	2027	2027
2	Central	Millbury Feeder Expansion	NA	2027	2027
3	Central	West Charlton Second Transformer	66	2028	2028
4	Central	Litchfield Street Feeder Expansion	NA	2028	2033
5	Central	North Grafton Second Transformer	66	2028	2033
6	Central	Pratts Junction Rebuild	66	2029	2029
7	Central	East Westminster Rebuild	102	2029	2029
8	Central	Westminster Rebuild	66	2029	2029
9	Central	East Winchendon Second Transformer	66	2029	2034
10	Central	North Oxford Second Transformer	66	2029	2034
12	Central	New Substation near Southbridge	132	2034	2034
13	Central	New Substation near Webster	132	2034	2034
14	Central	New Substation near Greendale	132	2034	2034
15	Central	Grafton Street Rebuild	132	2034	2034
16	Central	New Substation near Grafton	132	2034	2034
17	Central	Worcester Backyard Conversion Program	NA	NA	NA
18	Merrimack Valley	Power Company Road Feeder Expansion	NA	2028	2028
19	Merrimack Valley	Woodchuck Hill Rebuild	83	2029	2029
20	Merrimack Valley	South Billerica 18 Rebuild	103	2034	2034

21	North Shore	New Substation near Malden	132	2031	2031
22	South Shore	Norwell Upgrade	NA	2029	2034
23	South Shore	Belmont Second Transformer	16	2029	2034
24	South Shore	New Substation Near South Weymouth	132	2034	2034
25	Southeast	Whitins Pond Feeder Expansion	NA	2027	2027
26	Southeast	Beaver Pond Upgrade	37	2029	2034
27	Southeast	New Substation at Riverside	124	2031	2031
28	Southeast	New Substation Near Grand Army Highway	132	2034	2034
29	Western	Stockbridge Feeder Expansion	11	2028	2033
30	Western	Lenox Depot Rebuild	108	2029	2034
31	Western	Palmer Second Transformer	62	2029	2034
32	Western	Thorndike Feeder Expansion	NA	2029	2034
33	Western	Wendell Depot Feeder Expansion	NA	2029	2034

Note: Project list includes substation and distribution line projects to address load constraints (i.e., the projects included in the "Network Investments" category) and excludes ESMP CIPs.

The goal of this assessment was to determine the tradeoff between investment pace and affordability and the impacts a shift in balance would have on creating the expected capacity needs to meet the Commonwealth's interim targets, while maintaining a pathway to achieving the CECP 2050 net zero and other clean energy mandates. Additionally, by focusing potential investment pace shifts on network infrastructure, the Company would continue investment in the necessary technology, platforms, and programs to enable expanded use of NWAs to further defer or possibly avoid future investments in the future. If the Department determines that more weight should be placed on near-term affordability, the Company recommends that the Department provide a forum in which the pace of electric heating and transportation adoption are regularly reviewed so that the Department can take timely action as it sees fit.

Network Investments

The Company follows a rigorous Network Development Process to plan and deliver network infrastructure projects. The first two stages of this robust Network Development Process were carried out in preparation for this Future Grid Plan: (1) needs case development and (2) option selection.

Driven by the Distribution Engineering Planning Standard, needs cases for each project were developed based on system or customer-driven requirements. Scopes of work were developed based on asset condition assessments, system modeling, and opportunities were identified to bundle scope with other required work or existing projects at the given site.

These high-level options were then reviewed, analyzed, and compared for scope, cost, constructability, schedule, and risk to complete the project by the needed date. Permitting, work dependencies, bundling opportunities, parallel projects, and other considerations were also evaluated at this stage. This process was carried out by a dedicated multi-disciplinary team of experienced engineers, operations experts, cost estimators, and other experts to determine the preferred option to address each need. Wherever possible, the Company identified priority opportunities to explore non-wires alternatives (NWAs) as an alternative to defer capital investments in wires infrastructure such as substation and feeder upgrades (see Section 6.5.2 through Section 6.10.2).

The Company proposes to scale Conservation Voltage Reduction (CVR) and Volt/Volt-Amps Reactive Optimization (VVO), a previously approved Grid Modernization Plan (GMP) investment, through the Future Grid Plan as part of this investment category.

If the Company does not act upon these network investments, it would risk having insufficient network capacity to serve load growth as well as new DER, EV charging, and EHP connections. The capacity enabled by these network investments are necessary to achieving the Commonwealth's climate goals while maintaining the safety and reliability of the grid.

Platform Investments

This category of investments includes data requirements and technology platforms that would be needed to meet customer expectations and Commonwealth clean energy and climate goals. Several of these investments are a direct extension of the GMP, where they underwent rigorous Department review and were ultimately approved. These investments were developed prudently to maximize customer benefit and network performance, considering the network infrastructure buildout. The following are the Department's Grid Modernization objectives:

- Optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing);
- Optimize system demand (by facilitating consumer price-responsiveness); and
- Interconnect and integrate DERs.

The Company expanded upon already approved platform investments with incremental ESMP investments deemed necessary to meet customer expectations and Commonwealth clean energy and climate goals. The Company looked at how platforms could be built to extract, digitize, centralize, manage, optimize and then scale these data assets. This insight and the assessment of the Company's own existing internal data platforms demonstrated the need for drastic improvement to maintain the pace of growth of network infrastructure, while supporting electrification and meeting evolving customer needs.

The Company completed extensive roadmapping exercises to determine which initiatives would need to be foundational, enabling, or transformational. These roadmaps found that all underlying data must be real-time, accurate, interoperable, and thus scalable for transformational capabilities.

Customer Proposals

The Company's new customer offerings proposals come from insights from experience with current offerings, customer market intelligence, industry best practices, and gaps in meeting customer needs and enabling the net zero transition. The following are some factors that the Company considers in developing and evaluating new customer clean energy offerings, including for the Future Grid Plan:

1. Enablement of acceleration of the path to net zero;

2. Present and future customer needs;

3. Customer affordability;

4. Benefits to EJCs and low-income customers;

5. Scalability and speed-to-market;

6. Cost-effectiveness;

7. Market readiness;

8. Technical feasibility;

9. Network benefits and grid services (e.g., peak load reductions);

10. Appropriate fit within current and anticipated regulatory constructs.

Programs and offerings that satisfy some or many of these criteria were evaluated for inclusion in the Plan, and those investments that yield positive value and offer customer benefits are included in the Plan.

7.1.2 Alternative Approaches to Financing

The Company has two primary means by which to pursue alternative approaches to financing investments needed to achieve the Commonwealth's clean energy and climate goals beyond traditional cost recovery from all customers— (1) the Department's Provisional System Planning Program (i.e., CIP fees), and (2) pursuit of federal cost-sharing or other funding for relevant projects.

Department's Provisional System Planning Program (i.e., CIP fees)

In November 2021, the Department issued Order D.P.U. 20-75-B, Order on Provisional System Planning Program (PSP). The PSP provides a new framework for planning and funding essential upgrades to the electric power system to foster timely and cost-effective development and interconnection of distributed generation (DG) such as solar and energy storage. The provisional framework allowed the EDCs to file certain electric infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities.

Under the PSP, all distribution customers would fund the initial construction of these infrastructure upgrades and would be reimbursed over time from fees charged to DG facilities that are able to interconnect due to the Capital Investment Project (CIP) upgrades. These fees are specific to the CIP area, which is an electrical area with inter-dependent substations specifically interconnecting the applicable DG. Additionally, a portion of the costs of the infrastructure upgrades commensurate with demonstrated benefits to all distribution customers are allocated to all distribution customers and excluded from the CIP fee.

The Department's initial program under Department Order No. 20-75-B provided the Company with authorization to propose CIP fees in up to eight identified planning areas, of which the Company determined five were suitable candidates. Pending Department approval, the Company's proposed CIPs will enable $233 million in distribution system investment, creating 338 MW of DG hosting capacity, 107 MW of which is additional to the Group Study participants. Approval of the proposed investments and CIP fees is vital to advancing DG projects in the Company's interconnection queue to meet the Commonwealth's clean energy goals. The Company developed the proposed Future Grid investments assuming the pending CIP investments are made.

As of January 2024, the Company is currently processing multiple Group Studies for DG projects seeking to interconnect to the Company's network, and more such studies are likely. The Company proposes that the Department continue to allow EDCs to propose CIPs during the 2025 through 2029 ESMP term pursuant to the Department's D.P.U. 20-75-B cost allocation methodology, process, and Provisional System Planning Provision as the most efficient way to address the current constraints on the distribution system for interconnecting DG.[5] In this Plan, the Company is proposing to extend the D.P.U. 20-75-B cost allocation methodology, process and Provisional System Planning Provision to three new CIPs, following the completion of specific ongoing Group Studies, as described in Section 6.5 through Section 6.10 as applicable, with additional new CIP proposals for group studies of sufficient maturity to be made at the Company's discretion. This approach will provide the fastest and most equitable path during the five years of this ESMP to establish the capacity that DG projects need to connect to the distribution system, at the locations where they want to connect.

Federal Cost Sharing

The Company is competing aggressively for available federal funding that could help reduce the affordability burden of the clean energy transition on our customers. The Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) provide extensive opportunities for federal funding, tax incentives, and loans for clean energy infrastructure and production.

In October 2023, the Company was selected to receive a $49.6M competitive federal grant for an innovative smart grid technology project ("Future Grid Project") from the US Department of Energy (DOE) under the IIJA via the Grid Resilience and Innovation Partnerships (GRIP) Program.[6] Of this grant, $23.5M has been allocated to help support the Company's proposed platform investments in Section 6.3 with a portion dedicated to community benefits plan commitments as described in Section 12.2. This funding will result in customer benefits by helping to not only reduce the costs to the Company's customers but also to accelerate these new capabilities.

IIJA funding opportunities will continue to be released in multiple rounds over several years, and the Company will monitor competitive opportunities, including solicitations for joint proposals in partnership with the Commonwealth and other key stakeholders, and will submit additional applications in future years for certain investments that could qualify for funding.

The Company will also explore opportunities beyond competitive matching grants as appropriate. In a recent development for the utility industry, the IRA has provided an infusion of new funds into the DOE Loan Programs Office (LPO) for electric transmission and distribution investments that improve reliability and support electrification. The Company has been in contact with the DOE LPO and intends to apply for a federal low-interest loan to help reduce the costs of the Company's ESMP filing to our customers. The LPO application process is rigorous and lengthy, and thus the Company is taking steps now, so it is prepared to initiate the formal application after the Department issues an Order on the Company's ESMP. If the Company is successful in its application, the difference of several basis points can result in millions of dollars in savings for customers, and thus the Company considers it prudent to pursue such an opportunity.

[5] As of January 2024, the Department has approved one CIP Provisional System Planning Tariff (for Eversource) in D.P.U. 22-47; all other CIP proposals are pending before the Department for determination.

[6] https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2115_National%20Grid%20USA%20Service%20Company%2C%20Inc_v4_RELEASE_508.pdf

7.1.3 Customer Benefits

Customer benefits associated with the major investments in the Company's five-year plan are aligned with the 2022 Climate Act at 92B (B), which states that for all proposed investments and alternative approaches, each EDC shall identify customer benefits associated with the investments and alternatives including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts, and minimization or mitigation of impacts on the ratepayers of the Commonwealth (i.e., the eight customer benefits categories).

Exhibit 7.11 below illustrates the definitions of these eight benefit categories as the Company interprets how they align with the Commonwealth's clean energy and climate goals. Overall, the Company has identified customer benefits for the Future Grid Plan as a component of the net benefits analysis, showing how the Plan delivers substantial net benefits to customers. The methodology and results of the net benefits analysis are summarized in Section 7.1.4.

Exhibit 7.11: Benefits span eight primary categories outlined in the 2022 Climate Act

Safety:
Benefits of increasing safety and security for the public and utility workers, typically achieved by improving the risk profiles of current assets and/or replacing them with more reliable and secure technology.

Grid reliability and resiliency:
Benefits of upgrading infrastructure, grid hardening, and implementing technology to reduce the occurrence or impact of outage events and improve system performance and provide savings for customers.

Facilitation of the electrification of buildings and transportation:
Benefits from investments in transmission/distribution infrastructure meant to alleviate barriers to adoption of technologies such as electric vehicles and heat pumps.

Integration of distributed energy resources (DERs):
Benefits associated with improving interconnection and enabling DERs to expedite the clean energy transition.

Avoided renewable energy curtailment:
Benefits achieved through system investments aimed at alleviating capacity constraints and in turn, eliminating the need to curtail renewable energy generation on the system.

Reduced greenhouse gas emissions and air pollutants:
Benefits of investments that directly produce or enable reduction of greenhouse gases (GHGs) and other air pollutants such as carbon, nitrogen oxides, and particulate matter.

Avoided land use impacts:
Benefits to the environment and Commonwealth achieved through deploying infrastructure that has a smaller physical footprint than traditional utility infrastructure upgrades.

Minimization or mitigation of impacts on the ratepayers of the Commonwealth:
Benefits that reduce impacts to ratepayers via the minimization of future utility costs.

7.1.4 Net Benefits Analysis

The Company's proposed ESMP investments meet the requirements of the Climate Act and deliver benefits that will support long-term value for customers and enable the delivery of the public policy priorities of the Commonwealth. The Company completed a comprehensive net benefits assessment to capture the quantitative and qualitative benefits that customers will realize through delivery of its proposed ESMP investments. For a detailed summary of inputs, assumptions, and workpapers of the net benefits analysis, please refer to **Exhibit NG-Net Benefits-3 Net Benefits Analysis Report and Exhibit NG-Net Benefits-4 Net Benefits Model Workpapers**.

The Company forecasts the proposed ESMP investments will yield an estimated $821 million (present value) in quantified net benefits from investments completed in 2025 through 2029. In addition, the Company's proposed ESMP investments will help facilitate the achievement of the Commonwealth's climate goals by enabling significant levels of electric vehicles (EVs) and electric heat pump (EHP) adoption, timely integration of DERs, and modernizing the distribution system, while maintaining safe and reliable service.

The net benefits analysis also considers qualitative benefits, which contribute value even if difficult to express in quantified, economic terms. The Company includes a discussion of qualitative benefits from the ESMP investments for each of the eight customer benefits categories including safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of DERs, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, avoided land use impacts, and minimization or mitigation impacts on the ratepayers of the Commonwealth, as well as the benefits to and equity across EJCs.

7.1.4.1 Methodology

The Company worked jointly with Eversource and Unitil (EDCs) to develop a shared ESMP net benefits analysis methodology. The net benefits analysis produced both quantitative and qualitative benefits of the Company's proposed ESMP investments in accordance with the goals set by the Commonwealth.

Each EDC grouped their investments under common proposed ESMP investment categories with some differences in individual programs contained within investment categories, reflecting the differences among the EDCs' respective Plans. Exhibit 7.12 summarizes the common proposed ESMP investment categories that were agreed to by the EDCs, as well as the individual projects that the Company is proposing within each Future Grid Plan investment category. The Company's Plan includes five categories of investments: Network Investments, CIPs, Platform Investments, Customer Investments and Programs, and EV Programs.

Exhibit 7.12: Common Proposed Investments Summary

ESMP Investment Categories	Description	Company Specific Investments
Network Investments	New substation and distribution line upgrades to support electrification load growth and DER interconnections, as well as investments to install and manage additional technology to improve network operations and management	▸ Substation and distribution line projects for load growth ▸ Early fault detection ▸ Expanded CVR/VVO ▸ Integrated electric and gas planning ▸ Warehouse expansion to support Company workplan ▸ NG Facilities EV Fleet

Platform Investments	Investments identified to leverage data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs	- Network management technologies (i.e., DERMS) - Telecommunications - New digital products for asset planning, management, and operations - Data management - Security
Customer Investments and Programs	New programs and demonstrations to advance VPPs and use of DER for grid services, and investments in new clean energy customer portals & enabling technologies	- Customer portals for Clean Energy - Metering and Billing Systems - Flex Connect EV - Grid Services Compensation Fund - Building to Grid VPP - VPPs in EJCs
EV Programs	Continuation of existing EV make ready and charging infrastructure enablement programs	EV Phase III Program Extension
ESMP - CIP	Substation and line upgrades to enable DER interconnections with cost allocation	- New CIP (Substation Projects)
Resiliency	Undergrounding, reconductoring and other storm hardening infrastructure upgrades	N/A – resiliency spend included in the Company's Base Spending, not ESMP
Solar	Programs to support adoption of solar and storage technologies in EJCs	N/A
ESMP Program Administration	Program administration of incremental ESMP projects	ESMP Program administration

The net benefits analysis evaluated the portfolio of the Company's newly proposed ESMP investments over the first five years of the Plan (2025 through 2029), which are incremental to the Company's base (core) investments.

The costs for the net benefits assessment include all expenditures (capital and operational) included in the Company's 2025 through 2029 Plan as summarized in Exhibits 7.1 and Exhibit 7.2. For consistency with the duration of the benefits assessment, the costs also include estimates of the ongoing operational expenses to maintain the investments that would be in-service by 2029 over the lifetime of the asset or out to 2050, whichever occurs sooner.

The benefits assessment includes the benefits enabled from the Company's proposed investments that would be in-service by 2029. Benefits are modeled over the life of the asset or through 2050, whichever occurs sooner. For instance, a substation transformer that is put into service in 2029 will continue to support capacity on the network until 2050 and beyond, and thus will enable benefits resulting from the incremental adoption and usage of new clean energy technologies and resources over the duration of that timeline.

The net benefit estimates included in this section are based on a net benefits model calibrated to industry standard assumptions and any relevant inputs and assumptions cross-referenced with the other EDCs. Principles outlined in the National Standard Practice Manual (NSPM) and DOE's Modern Distribution Grid (DOE) documents state that net benefits should account for state regulatory and policy goals, account for all relevant costs and benefits (including hard-to-quantify), apply full life-cycle analysis, and assess investments as bundles and portfolios instead of separate measures. Accordingly, the EDCs developed a net benefits framework for the ESMP incremental investments using a "regulatory perspective",[7] as suggested in the NSPM, to evaluate the benefits categories as defined in the Commonwealth's 2022 Climate Act at 92B (B) for the ESMP, i.e., 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. Furthermore, the net benefits analysis factors in broader economic and workforce benefits in addition to the benefits listed in Section 92B that result from the Company's Plan using a RIMS-II analysis.

The Company provided all data related to the costs of its proposed ESMP investments for use in the net benefits model. A common methodology for the investments common across EDCs was determined, and the EDCs then identified relevant input factors and assumptions that could be used to estimate the benefits enabled by the proposed ESMP investments.

Net benefits assessed in this analysis were aligned to the eight benefit categories outlined in the 2022 Climate Act. In addition, economic and EJC benefits of the investment proposals were captured in the net benefits analysis. The EDCs evaluated the potential categories of benefits enabled by the proposed ESMP investments and determined which categories of benefits could be quantified (monetized and non-monetized) and which could be described qualitatively.

Quantitative: Benefits were quantified when industry standard data and documented methods were available to do so, and further steps were taken to monetize those benefits when possible and appropriate (i.e., to avoid double counting). Quantitative benefits are calculated in the net benefits model. They are aggregated to form an overall result. Quantified benefits were calculated across the following categories:

- Reduced GHG emissions & air pollutants
- Minimization or mitigation of impacts on ratepayers of the Commonwealth
- Grid reliability and resiliency
- Economic Benefits (via the RIMS-II model, described in Section 12)

[7] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Qualitative: These benefits are outcomes of the investments contained in the Plan for which there is insufficient data to estimate quantitatively. These benefits were evaluated across the eight benefit categories described in the 2022 Climate Act and noted in Exhibit 7.12 on pages 21-22. The net benefits analysis also captures the reduction of environmental burdens in pollution-affected areas, emphasizing historical inequities in EJCs.

The collective benefit contributions from the Company's proposed Plan that were evaluated in the net benefits analysis – both quantitative and qualitative – are illustrated in the following section. It is important to recognize that while these attributions were made to support the creation of the net benefits analysis, it is the Company's proposed solution as a whole, and not the individual investment categories alone, that unlock these benefits to meeting the Commonwealth's climate goals. As such, individual investment categories should not be considered on their own – given certain investment interdependencies, alterations to one investment category may have cascading effects on the net benefits as a whole, as other investments within other categories may have a significantly altered benefit impact.

Exhibit 7.13: Benefits Attribution in the Net Benefits Assessment

LEGEND: ■ -Quantitative Benefit ■ - Qualitative Benefit

	BENEFITS CATEGORIES									
INVESTMENT CATEGORY	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	Minimization or mitigation of impacts on ratepayers of the Commonwealth	EJC Impact	Economic Benefits
NETWORK INVESTMENTS	■	■■	■	■	■	■■		■■	■	■■
CIPs	■	■	■	■	■	■■		■	■	■■
PLATFORM INVESTMENTS	■	■		■	■	■■	■		■	■■
CUSTOMER INVESTMENTS		■	■	■	■	■	■	■	■	■■
EV PROGRAMS			■	■		■■		■■	■	■■

7.1.4.2 Net Benefits Analysis Results

Quantitative Benefits

The net benefits analysis model shows the quantitative net benefits based on the investments associated with the first five years of the Company's proposed investments. Exhibit 7.14 on following page illustrates the estimated monetized benefits, nominal costs, and present value (PV) of the Plan and is referred to as the principal net benefits analysis result.

Exhibit 7.14: Net Benefits Model Result for Monetized Customer Benefits

Benefits & costs	Nominal ($M)	PV ($M)
Costs:	**$3,169**	**$2,137**
Capital (5-year ESMP)	$2,052	$1,576
O&M (5-year ESMP)	$469	$353
Total Ongoing O&M	$648	$208
Benefits: (Asset Life or through 2050):	**$8,587**	**$2,958**
Reduced GHG emissions & air pollutants	$7,843	$2,395
Grid reliability and resiliency	$122	$40
Minimization or mitigation on ratepayers of the Commonwealth	$121	$58
Economic Benefits	$501	$465
Net benefits:	**$5,418**	**$821**

The present value of monetized benefits outweighs the costs for the Company's proposed ESMP investments. It is important to note that the Company's proposed investments enable additional benefits that cannot be monetized or quantified, so the monetized benefits do not fully capture the true net benefits resulting from the proposed Plan. The full suite of net benefits, both quantitative and qualitative, provide a holistic view of net benefits relative to the costs of the proposed ESMP investment portfolio.

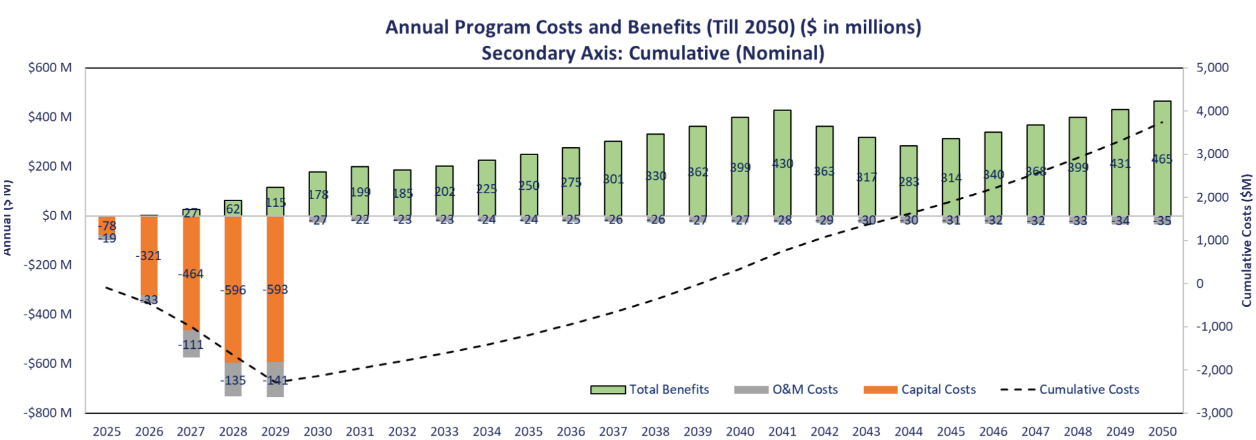
These monetized benefits are largely driven by the reduction in GHG emissions enabled by the investments, the monetized impacts of which are estimated based on the social cost of the GHG or air pollutant emissions. These ESMP investments collectively enable emissions reductions by delivering additional capacity to electrify transportation and buildings, as well as to connect distributed generation.

Exhibit 7.15: Quantified Benefits by Investment Category

		QUANTITATIVE BENEFITS BY INVESTMENT ($PV)				
Investment category	**Investment cost ($M)**	**Reduced GHG emissions & air pollutants ($M)**	**Grid reliability and resiliency ($M)**	**Minimization or mitigation of impacts on ratepayers of the Commonwealth ($M)**	**Total benefits ($M)**	**Total including Economic Benefits ($M)**
Network Investments	$1,344	$1,212	$40	$55	$1,307	$465
CIPs	$52	$348	N/A	N/A	$348	
Platform Investments	$360	$26	N/A	N/A	$26	
Customer Investments	$122	N/A	N/A	N/A	N/A	
EV Program	$221	$809	N/A	$3	$812	
ESMP Program Administration	$38	N/A	N/A	N/A	N/A	
Total ($PV)	**$2,137**	**$2,395**	**$40**	**$58**	**$2,493**	**$2,958**

As shown in Exhibit 7.15, the net benefits associated with these investments yield net positive results by 2044. Most costs occur in the five-year investment period, including capital costs for the five-year Plan (2025 through 2029) and relatively small amounts of the ongoing O&M costs to maintain the investments that would be in-service by 2029 over the lifetime of the asset or out to 2050, whichever occurs sooner. Benefits are assessed from the in-service date in 2029 through 2050 and will increase over time as more clean energy devices (EV, EHP, solar) connect to the network, leveraging the capacity enabled by these investments.

Exhibit 7.16: Annual Program Costs and Benefits (2025 to 2050)



The net benefits analysis factors in the non-monetized benefits that result from the Company's proposed ESMP investments, which feed into the quantified, monetized result. These non-monetized benefits show quantitatively how the proposed ESMP investments in the first five years of the Plan enable the Commonwealth's 2050 climate goals, support the customers of the Commonwealth, and increase economic development.

Exhibit 7.17: ESMP Five-Year Total Quantified Outcomes Driving Monetized Benefits

Quantified Outcomes Driving Monetized Net Benefits	Total
Total MT CO2 Reduced	31.3M MT
Total MT NOx Reduced	7,462 MT
Total MT PM 2.5 Reduced	162.7 MT
Total Electric Vehicles Enabled	492K EVs
Total Heat Pumps Enabled	84K EHPs
Total Distributed Generation Enabled (MW)	1,179 MW

In addition to the net benefits assessment, the EDCs have also evaluated the economic benefits resulting from the Company's proposed Plan. As part of the net benefits analysis, the Company performed a workforce and economic analysis, using the RIMS-II model. The results of the workforce and economic analysis, including direct and indirect jobs impact and economic impact (via the RIMS-II model), are discussed in Section 12.4 of the Plan.

Qualitative Benefits

Qualitative benefits contribute value even if difficult to express in quantified or monetized terms. These benefits represent additional key reasons for implementing the portfolio of ESMP investments and related programs when considered in aggregate. The qualitative benefits and their alignment to the benefits outlined in the 2022 Climate Act are detailed in Exhibit 7.18. A key qualitative characteristic of this Plan is the integrated nature of the package of investment proposals. This package of investments will collectively support the Company's ability and capacity to support the Commonwealth's emissions targets.

Exhibit 7.18: ESMP Qualitative Benefits Summary

Category	Qualitative Benefit Description
Safety	▸ **Investment alignment with the Company's Guiding Principles of Safety and established equipment standards and work methods**, through assurances that professional safety protocols employed support the Company's regulatory and operational goals, its legal and customer obligations and its drive toward world class performance. ▸ **Increased worker safety** via proposed investments that improve reliability which reduce time spent near electrical hazards, particularly during dangerous conditions (i.e., storm response). ▸ **Improved protection of software systems and physical assets** from security threats and malware, enabling stable and secure operations.

Grid Reliability and Resiliency	▸ **Keeping our customers powered consistently and reliably** through grid-impacting events. While the impetus for the Company's substation and feeder projects is to address capacity deficiencies in supporting the Commonwealth's clean energy and climate targets, the network investments will have secondary benefits in improving grid reliability and resiliency. For instance, the substation investments in locations identified as having a high risk of coastal flooding have incorporated flood mitigation considerations in the scope development. Substations and feeder expansion projects driven by a network capacity deficiency provide an opportunity to replace higher-risk aging infrastructure and to underground select areas for improved reliability and resiliency. ▸ **Technology investments such as early fault detection and active power restoration services** will help improve reliability by proactively detecting faults and resiliency through integrating DER into the Company's outage restoration strategy ▸ **The Company's platform investments include the technologies necessary to transform our future ability to leverage DER on the network for grid services**. The Company's initial focus is to leverage DER to help manage load growth on the network via non-wires alternatives (as described in the Policy & Solutions testimony). As the Company matures in these capabilities it will test and scale its ability to use grid edge flexibility to address additional grid use cases, which could include reliability and resiliency use cases. ▸ **The proposed communications investments**, including the Company's continued deployment of a private fiber network will enable greater network control, performance and availability (uptime) than what commercial telecommunications carriers provide.
Facilitation of the Electrification of Buildings & Transportation	▸ **Availability of adequate capacity and foundational enablement for clean energy** through expanded electric distribution infrastructure, to create adequate supply that meets the needs of customers transitioning to electric transportation and heating. ▸ **Increased support for EV and electric heating adoption** via increased capacity and incentives from EV customer program extensions. ▸ **Reducing the long queues at public and workspace chargers**, alleviating range anxiety and traffic through increased enablement of new, more accessible EV charger deployments.
Integration of Distributed Energy Resources	▸ **Remediating interconnection process pain points** which reduces the friction experienced by our customers to bring new clean energy assets online and electrify, such as through CIP proposals. ▸ **Proactive capacity availability to make it easier for large spot loads to connect** in the future through substation and feeder investments. ▸ **Improved customer connection experience** through increased transparency in the interconnection process, customer-facing portal enhancements, and DERMS investments to reduce the study time for new connections, as well as enabled flexible connections alternatives at scale.
Avoided Renewable Energy Curtailment	▸ **Increased grid flexibility** through platform investments and customer programs that allow for future time-varying rates, new pathways for VPPs to provide grid services both for distribution system needs as NWAs and to support the wholesale market via FERC 2222, collectively help to align customer energy usage with intermittent renewable production. These coordinated programs optimize grid operations and use of DERs to avoid distribution constraints, while avoiding renewable energy curtailment.

Reduced GHG emissions & air pollutants	▸ **Accelerating the transition to a Net Zero GHG economy, delivering on the CECP's GHG reduction goals**. The Company's collective investment proposal was engineered to support a higher integration of renewables and DERs, helping reduce dependence on fossil fuel generation, and decreasing the release of GHG emissions, which contribute to climate change. The company has developed quantitative estimates of the CO2 emissions reductions enabled from the ESMP, which are described in the quantitative section above. While the Company has included a quantitative assessment of GHG reduction benefits, there are qualitative benefits associated with delivering the state's climate goals that cannot be quantified. The analysis does not model methane (CH4) emissions quantitatively though acknowledges that CH4 is an even more potent GHG than CO2. The Company's investments may have downstream impacts on reduced CH4 as well. ▸ **Reduction of other non-GHG, criteria air pollutants**, such as sulfur oxides (SOX), nitrogen oxides (NOX), and fine particulate matter (PM2.5), that have well documented impacts on respiratory and cardiac disease. While the Company used EPA to estimate the public health impacts with reducing NOX and PM2.5 emissions, the Company acknowledges that there could be other qualitative benefits associated criteria air pollutant emissions reductions, such as reduced smog.
Avoided Land Use Impacts	▸ **The Company's Plan includes two asset deferral NWA projects, which will defer the implementation and associated construction** of two feeder expansion projects. As the Company continues to develop capabilities and learn from its initial NWA projects over the course of this five-year Plan, it envisions implementing additional NWA projects in the future to help defer future land use from new construction projects. ▸ **All of the Company's proposed substation projects** to be in-service by 2029 included in the Plan, both for its ESMP network infrastructure and ESMP CIP investments, involve upgrades and rebuilds at existing substations, rather than delivery of new greenfield substations, which minimizes the requirement for additional land use.
Minimization or mitigation of impacts on ratepayers	▸ **Creation of customer earning opportunities and increased customer** choice. The Company's plan includes several enabling investments and program that will increase customer choice and help customers take greater ownership of their bill, including extension of the Company's existing off-peak charging rebate program, enabling metering and billing system investments to support future new rate options (i.e., time varying rates subject to future dockets), customer portal investments to improve ease interconnections process to increase customer access to bill savings opportunities from solar and storage, and expanded opportunities to earn value as "prosumers" via new grid service programs (i.e., for Non-Wire Alternatives), which will become increasingly important to the Company's delivery of a clean energy network. ▸ **Minimizes future utility spend (and thereby reducing pass through to customers)**. While addressing imminent system needs with its proposed ESMP investments, the Company used its long-term demand forecast to design those solutions to also account for long-term growth in demand and DER adoption beyond the usual 10-15-year study period timeframe. Absent this long-term perspective for ESMP investment planning, the Company in many instances would need to make successive investments in an asset or area, to react to electrification load growth and clean energy deployment as they grow over time. Rather, the Company's approach results in more comprehensive solutions to meet customer and community needs for the long term. The alternative approach—i.e., a patchwork of multiple investments made to resolve successive capacity deficiencies over time—would result in delays in meeting customer and community needs, and greater expense over the long run.

	‣ **The Company's Plan includes two asset deferral NWA projects to cost-effectively defer** implementation and the associated costs of two feeder expansion projects. The Company is maturing NWA and flexible connections capabilities in this ESMP, such that it can more confidently and precisely use flexibility in the future to cost-effectively defer more traditional infrastructure upgrades and their associated costs to customers.
Other (Benefits enabled outside those defined in the 2022 Climate Act)	‣ **Make it easier for businesses to operate and thrive in the Commonwealth** – Investments in expanded capacity and supporting technologies will make the network "connection-ready" ensuring there is availability where it is needed to help expedite new customer connections, EV fleet adoption, electric heating conversions, and DER interconnection. The investments will also have secondary benefits on reliability and resilience. These attributes will help attract and retain businesses and associated economic activity within the Commonwealth. ‣ **Progressing towards an additional 3,000 MW of capacity**. The Company's proposal for this ESMP period includes substantial costs associated with projects that will not be in-service until the 2030 through 2034 ESMP. As such, their associated benefits were not included in the net benefits analysis but are tangible benefits that will be realized in a future ESMP period.

7.1.4.3 The Company's Role in Driving Customer Benefits within EJCs

While the proposed investments in the Company's Plan were engineered to enable the timely realization of the 2022 Climate Act's long-term decarbonization targets among a plethora of additional benefits, the Company recognizes that several identified benefits are contingent on customer action – e.g., purchasing electric vehicles, electrifying space heating, or adopting other distributed energy resources. The Company also recognizes that many of our customers, especially those in identified EJCs, have historically faced high energy burdens, yet may not have adequate awareness of the available assistance programs, resulting in lower program enrollments.

A key goal of the Company's proposed Plan is to drive the investments and their associated benefits in a more equitable fashion going forward. The Company's net benefits analysis takes a holistic, territory-wide approach to estimating the net benefit of the total investment. The net benefits analysis did not assess the specific, quantified benefit outcomes realized on a community-by-community basis or by EJCs specifically. rather than quantifying outcomes on a community-by-community basis or by EJC. Benefits identified directly to EJC communities would require a number of uncertain assumptions on adoption rates or the modeling of specific customer behaviors at a very granular level that would also need to be both reasonable and defendable.

However, the proposed Plan includes two primary actions that will be driven by the Company and, where appropriate, in collaboration with the other EDCs, to break down historical barriers and facilitate benefit realization in a more equitable fashion. These include: (a) providing offerings and programs for EJCs and LMI customers that will allow them to more readily participate in the clean energy transition and lower their bills (including both new offerings proposed in this Plan and existing programs that the Company will continue); and (b) establishing formal, accountable frameworks for stakeholder engagement and outreach such that customers are aware of and can take advantage of these programs, both described in more detail below:

a) **Providing Programs and Offerings for EJCs and LMI Customers**. As described in **Section 6 (Section 6.1)** and in **Section 3 (Section 3.4)**, the Company outlines a number of specific EJC- and LMI-focused programs to support fleet electrification (infrastructure rebates and charging incentives), providing no-cost energy efficiency upgrades and weatherization improvements, flexible load incentives to support VPP demonstrations in EJCs, general rate assistance programs, solar lease options, and much more. These customer programs, such as its successful EE and EV programs, have benefited from the input of EJCs to inform program design that reflects community priorities. For example, engagement through the EE Equity Working Group has played a crucial role in establishing specific goals for equity and service for EJ populations. For EE and EV programs, more enhanced EJC incentives are offered for residential customers and more direct support of fleet electrification is a priority to reduce local air pollution.

b) **Supplementing with Intentional and Accountable Stakeholder Outreach**. As described in **Section 3 (Sections 3.4 and 3.5)**, engaging stakeholders in an equitable manner is critical for the development and execution of the Company's Future Grid Plan. This is supported by the establishment of two-way engagement channels, developing rigor in joint-collaboration (both across EDCs and with stakeholder groups), and providing tailored outreach to drive a community-centric focus that is both culturally competent and respectful to those communities' specific needs. This outreach can drive greater adoption of EJC- and LMI-specific programs, in turn allowing for the realization of the associated decarbonization benefits.

The Company takes seriously its commitments to driving equity in its Future Grid Plan with thoughtful and meaningful community benefit as a critical outcome requirement for the investment, spanning not just grid-benefitting operational improvements, but also in advancing energy democracy, workforce development, and community partnerships. These efforts will be iterated on and improved through future ESMPs.

7.2 Investment Summary 10-year Chart

As shown in Exhibit 7.19, the Company's capital plan for the ten-year period (2025 through 2034) continues to invest in programs and initiatives to ensure safe, reliable, and resilient infrastructure that enables the just transition to a cleaner energy future. Some of the drivers of spend in the ten-year period include the completion of certain programs by end of the first five years. Spending in the second five years is more heavily driven by peak load and capacity programs.

Exhibit 7.19: ESMP 2025-2034 Capital Investments ($M)

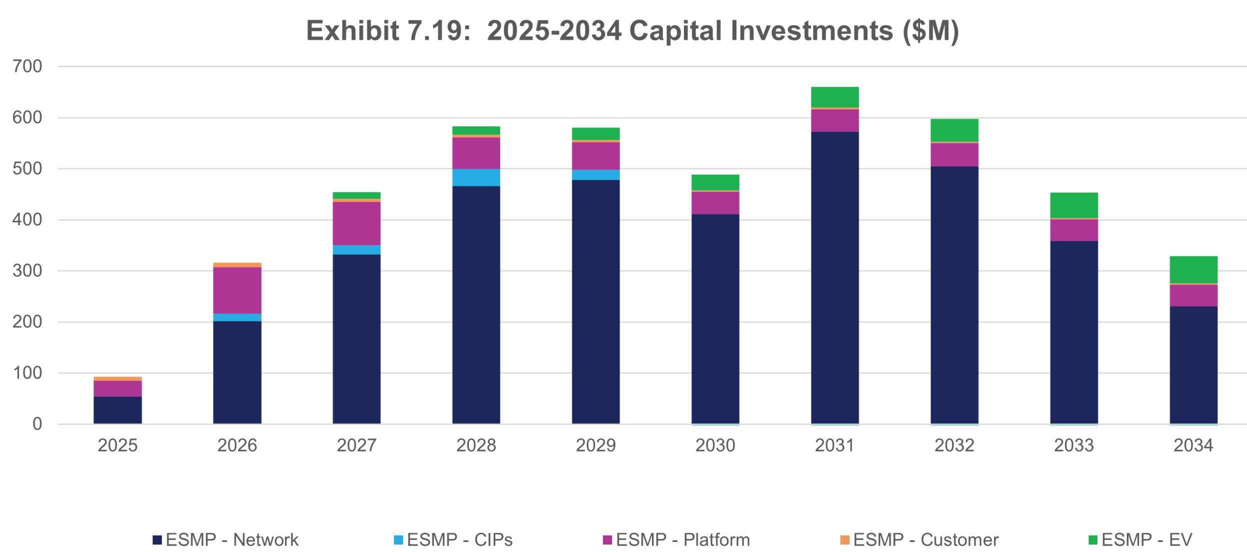


Exhibit 7.20: 2025-2034 Capital Investments ($M)

Categories	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ESMP: Network	54	202	333	466	478	411	572	505	359	231
ESMP: CIPs	(16)	15	18	33	20	-3	-3	-3	-3	-3
ESMP: Platform	31	91	85	62	54	43	44	45	41	42
ESMP: Customer	7	8	6	5	4	3	3	3	3	3
ESMP: EV	0	0	13	17	24	30	41	45	49	53
ESMP: Subtotal	**77**	**316**	**454**	**583**	**580**	**485**	**658**	**595**	**450**	**326**

7.3 Execution Risks – Permitting, Supply Chain and Workforce Challenges

The magnitude of work required to meet the Commonwealth's goals and to deliver the required volume of infrastructure projects is significant and unprecedented compared to recent history. To ensure that the Company can deliver on the objectives outlined in this Future Grid Plan, it is critical that the Company develop a solid plan for executing this work. There are many external factors that impact the Company's ability to execute work including land availability, securing permits, procuring equipment, resource availability, and managing stakeholder expectations and gaining their support. Any one of these factors can lead to risks to the Company's ability to execute the Plan as proposed. While developing this Plan, the Company considered these factors and is confident that the objectives it has set can be successfully executed.

The Company has developed a plan detailing how it will deliver the scopes of work outlined in this Future Grid Plan, including the assumptions, portfolio risks, and mitigation measures in progress. The Company's overall approach to developing this Plan was to evaluate the risks and assumptions for each substation project group in the portfolio and assign them an execution risk score. Each project group is made up of many individual projects (including land purchases, substation expansion or new construction, distribution line undergrounding or overhead construction, telecom, and protection and control) required to meet the electrical need in the area.

These execution risk scores were assigned based on criteria such as need for land acquisition, environmental considerations, need for permitting, technical complexity, existing concurrent work (outside the scope of the Future Grid Plan), siting and permitting regulations, and third-party dependencies (such as a neighboring utility or generation). The cross-functional team assigned to each project then developed project schedules detailing siting, permitting, engineering, material procurement, and construction durations required to complete each project group. The execution score assigned to a project group determined the durations for each project.

More complex projects will require longer durations. For example, building a new substation would require additional time to purchase new land, undergo extensive permitting requirements, construct any associated transmission lines, and potentially undergo community impact assessments. These complex projects also need major materials with longer lead times such as transformers. An example of a higher-risk project group that would take longer to complete could involve an extensive initial siting process, the purchase of new substation land in a congested area, and then having to site and build several miles of underground transmission line, again requiring extensive permitting.

During the first 5-year ESMP period (2025 through 2029), 21 projects are projected to be ready to go into service. The project groups that will go into service during this period are generally ones that have lower execution risk and can be done in a quicker timeframe. During this period, the Company will also begin preliminary land acquisition or engineering activities on many of the subsequent projects that will go in-service in 2030 or later.

The Company will look for ways to optimize its delivery process and seek innovative solutions to help reduce schedule risks. For example, the Company will further evaluate opportunities for standardized engineering designs, continuing to streamline the capital delivery process, partnering with communities to ensure they can provide feedback into the siting process, and streamlining permitting durations. The associated risks and mitigation efforts are described below:

Energy Facilities Siting Board (EFSB) Approval Process Timeline

Many of the proposed projects will require extensive permitting, including approval from the EFSB. Based on recent projects, the Company assumed a timeline of three years from filing to approval of a new EFSB permit. The EFSB has a desired target of one year to complete and issue permits; however, due to resource constraints and workload, the EFSB has not been able to meet this target. Based on the current scopes of work, the current project groupings would necessitate several separate EFSB approvals. To meet its assumed delivery timeline for the 10-year ESMP network investment plan, the Company would need the EFSB to be able to process the Company's applications faster than the current three-year timeframe and to process them concurrently (rather than one at a time).

If the Company's EFSB applications cannot be processed more quickly than three years or concurrently, there is a risk that the Company will not meet the schedules assumed in the 10-year Plan—the 5-year plan has fewer projects with anticipated EFSB approval requirements. The Company will discuss with the EFSB how to partner to help improve the current review and approval timeframe and if there are different ways that the Company can bundle permits or sequence submittals to improve the process. Internally, the Company will invest further in project-specific alternative exploration and analysis to determine the preferred path forward. This evaluation process may uncover ways to defer or avoid the EFSB process through alternate scopes of work.

Land Acquisition & Permitting

Many of the projects will require property acquisition to build out the proposed network investments. Based on the current scopes of work, the Company expects the need for many separate parcels for new substation sites along with several additional smaller property acquisition needs for expansion of existing assets. Through early engagement and partnership with impacted external stakeholders, the Company will be able to secure the necessary land parcels needed to build new substations and obtain necessary permits in a timeframe that supports the Company's schedules.

If the Company cannot secure the land for the new substations or obtain the necessary permits for the substations or transmission and distribution lines, there is a risk that the schedule proposed above will not be met. After performing a review of the areas where these substations are required, the Company believes that it is possible to locate the required substations where they are needed, but it may be challenging due to congestion, limited availability of land, or permitting challenges.

Community resistance to substation land purchases, new transmission overhead or underground lines, new distribution overhead or underground lines, or substation construction could cause a significant delay to the project schedules and impede the Company's ability to execute a project.

To manage the risk of not acquiring land in the timeframe required to support the schedules, the Company will put together a dedicated team focused on the identification and preliminary assessment of siting and purchasing considerations of land. This will allow the Company to work with its Customer and Community teams to engage communities to develop a shared understanding of the needs, benefits, and impacts.

Major Materials

The Company is seeing an increased lead time for major materials. For example, power transformers lead times can take three years from order to delivery. The Company will work with established and new manufacturers to secure long-term contracts and a pipeline of production slots that can meet the increased demand for major materials such as power transformers, control enclosures, steel structures, circuit breakers, and switches.

There is risk that the Company will not receive the necessary major materials in the timeframe required to support its construction schedules. Utilities across the country are embarking on large-scale infrastructure investment programs which also require large quantities of materials in the same timeframe. To mitigate this risk of market competition, the Company is laying out a forecast of major materials by year and will partner with existing and new manufacturers on future orders and commit to necessary production slots over 10+ years.

Resources

The Company has ongoing strategic workforce planning efforts underway to assess and plan for the incoming project workload given the Future Grid Plan and industry projections (See Section 12). However, as mentioned earlier, given the magnitude of workload that is anticipated, the Company foresees this to be one of the major deliverability challenges.

The Company will have strategic discussions with existing and new construction contractors and engineering firms, which will enable the Company to partner with them to find ways to complete all the work in this Plan in a timeframe that supports the Company's schedules. The Company will also work diligently to recruit and hire the necessary internal resources required to support this Plan.

If the Company cannot secure the necessary resources (internal or external), there is a risk that it will not be able to complete the Plan in the scheduled timeframe. To mitigate this risk, the Company is providing long-term visibility and forecasting to its contractors and conducting strategic discussions with engineering and construction firms to discuss approaches to completing all work proposed in the Plan. The Company will explore various contracting strategies, including Engineering, Procurement, and Construction (EPC) strategies. The Company will also develop internal hiring strategies for the necessary resources to support this Plan. The Company anticipates an industry-wide risk in this area that other utilities may face, which emphasizes the importance of starting bottom-up workforce programs now to get the emerging generation into the energy field.

Optimize Delivery Processes

The Company recognizes the importance of optimizing its engineering and project delivery processes to efficiently deliver the portfolio of projects and associated outcomes. If the Company cannot find ways to optimize delivery processes, there is a risk that it will not be able to accomplish all the work laid out concurrently. The Company will pursue ways to optimize its engineering and project delivery processes to identify work delivery and scheduling efficiencies. For example, the Company is considering strategies such as further developing engineering design standards and continuing to, streamline its process to deliver capital projects, standardize its equipment specifications, and streamline the procurement and contract management processes.

Section 8

2035 - 2050 Policy Drivers: Electric Demand Assessment

This section describes the results and methodology for the 2035-2050 electric demand assessment used by the Company, including discussions of electric heating and transportation and DER adoption.

Key Take-Aways

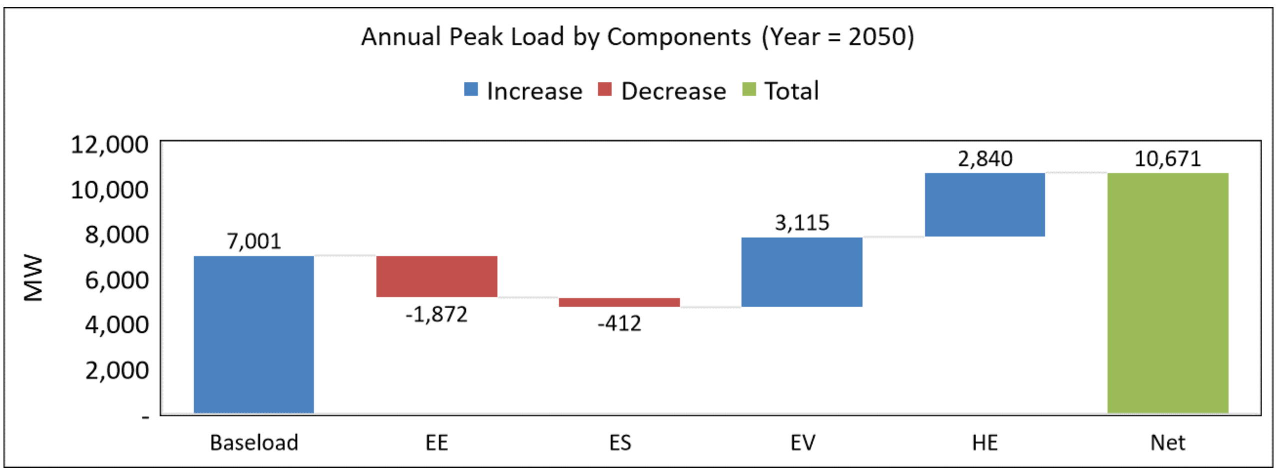
- The Company's demand assessment to 2050 aligns with the Commonwealth's Clean Energy and Climate Plan and its preferred 2050 net zero pathway.
- Looking farther out in time, the level of uncertainty increases given the range of potential economic, technological, market, and policy drivers at play in projecting electricity demand out to 2050.
- The Company has modeled a wide array of long-term demand scenarios. Even under the lowest demand scenario, beneficial electrification leads to a more than doubling of peak demand versus today by 2050.
- The Commonwealth's goals for heat electrification mean that winter peak surpasses summer peak demand by 2036 as heat pumps become a dominant demand growth driver.

8.0 2035 - 2050 Policy Drivers: Electric Demand Assessment

In this Section, we will provide an overview of the methodology and results of the 2035 – 2050 Electric Demand Assessment. This forecast, which is modeled to meet the Commonwealth's climate goals via the "All Options" and "Phased[1]" Scenarios in the CECP, shows that electric demand will more than double between today and 2050. This increase in load is primarily driven by beneficial electrification in the transportation and heating sectors (see Exhibit 8.1). Notably, Electrification of Heating (EH) is expected to cause the system to switch from summer to winter peaking in the late 2030's. Solar PV, which had a substantial impact in keeping demand roughly flat in recent years, will have minimal impact on peak demand by 2050 because the peak is projected to switch from the summer afternoon to winter evenings when there is little sun.

These long-term forecasts inform the need for investments in both the short term (2025 to 2034, as described in Chapter 6) and long term (2035 to 2050, as described in Chapter 9). In the short term, the Company will need to build long-lead time network infrastructure to increase capacity, expand foundational technology platforms, and implement customer programs to incentivize adoption of distributed energy resources and energy efficiency technologies. Beyond 2035, these programs will need to continuously evolve based on best practices and changes in demand patterns in the future.

Exhibit 8.1: Annual Peak Load Components by 2050



Methodology

The same methodology from the 5- to 10- year forecasts in Section 5 was used for the 2035 to 2050 electric demand assessment described in this Section. The base scenario for the demand assessment is continuous with the 5- and 10-year forecasts from Section 5 and aligns with the Commonwealth's decarbonization goals. As mentioned in Section 5, high and low sensitivities around different technology and policy scenarios are also considered for the demand assessment to account for increased uncertainty over time.

[1] The "Phased" Scenario is a refinement of the "All Options" Pathway with a focus on residential space heating. The "Phased" approach was used as the basis for the CECP's emissions targets and the lowest cost scenario that was modeled. (Massachusetts Clean Energy and Climate Plan for 2025 and 2030, Published June 30, 2022 - https://www.evolved.energy/post/massachusetts-clean-energy-and-climate-plan).

Uncertainty

There is much uncertainty about what electric demand will look like in 2050. Today, there is low penetration of electrification of the building and transportation sectors so there is limited empirical data for building demand profiles, adoption rates, and propensity models. It is currently unknown how much impact emerging technologies or programs (such as transportation and heating electrification, or time varying rates and managed EV charging programs) might have on future demand.

To account for uncertainty further out into the future, the Company uses base, low, and high scenarios to generate a range of possible outcomes to address uncertainty in its 2035 to 2050 forecasts, as described in Exhibit 8.2 below.

Exhibit 8.2: Base, Low, and High Scenarios for Long-Term Forecasts (2035 to 2050)

Scenarios	EE	PV	ES	EV	HE
BASE	Assuming continuous growth of incremental EE but at a slower rate, reflecting the saturation of the market and the uncertainties regarding available funding and supportive policies.	Reaching the Company's distributed energy resource share of the Commonwealth's "All-Options" scenario policy goal.	Exceeding the Company's distributed energy share of the Commonwealth's "All Options" scenario policy goal	**LDEV:** Based on Commonwealth's adoption of California's ACC-II Rule and considers transfer flexibilities in the Rule MHDEV: Based on Commonwealth's adoption of California's ACT Rule	Modeling the trajectory towards meeting the Commonwealth's CECP "Phased" scenario, which assumes adoption of both partial and full heat pump systems and allows for hybrid fossil-fuel and electric heating systems. The "Phased" scenario is also the Commonwealth's preferred electrification scenario because "it presents both long-term and near-term benefits over other building decarbonization approaches analyzed"[2]
LOW	Compared to the Base, assuming lower growth rate, reflecting rising EE baselines leading to lower levels of claimable savings and shifting of resources to electrification of heat programs	Reaching the "**All-Options**" scenario policy goal slightly later	Compared to the Base, considering smaller distributed energy share (i.e., more on wholesale system as supply)	**LDEV:** Managed EV home-charging assuming increasing home-charging access and participation over time **MHDEV:** Based on Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook	Hybrid utilization of fossil-fuel and EHPs is more common, aligning with the Commonwealth's outlook for the "**Hybrid**" scenario

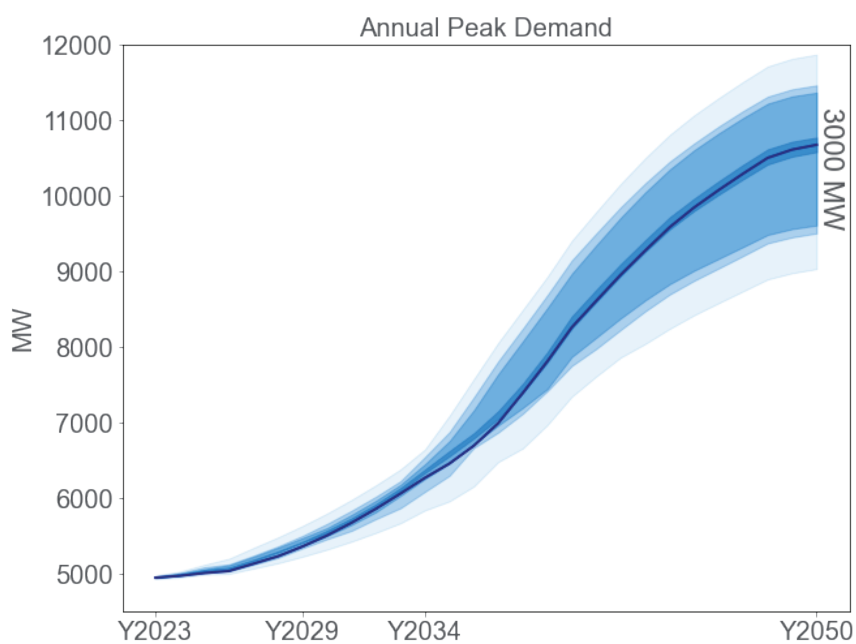
[2] Massachusetts's Clean Energy and Climate Plan for 2025 and 2030, June 30, 2022, page 26

HIGH	Compared to the Base, assuming slower saturation	Reaching the "**All-Options**" scenario policy goal sooner	Exceeding the Company's distributed energy share of the Commonwealth's "Phased" scenario policy target	**LDEV:** Still based on Commonwealth's adoption of California's ACC-II and assumes no transfer flexibilities **MHDEV**: Reflects an accelerated adoption rate	Assumes more rapid adoption of full EHP systems and results in higher full EHP penetration through 2050, which aligns with the Commonwealth's assumption for the **"Full Electrification**" scenario

Based on these scenarios, the Company has generated a range of possible demand growth outcomes between today and 2050. As shown in Exhibit 8.2, the difference between baseload and net peak load is roughly 3,000 MW or approximately 30% of expected demand under the "All Options Scenario" from the CECP in 2050.

Demand forecasts and the associated range of uncertainty will change over time. As new technologies (such as electrification of transportation and heating) mature and become more prevalent, increasing data will become available on the adoption and load profiles of these technologies. This data can then be incorporated into future iterations of the model, thus lowering uncertainty on forecasted demand. As the Company invests in new capabilities to enable flexible load resources, including EV managed charging, TVRs, aggregation of DERs, and flexible heating demand, there is the opportunity to "bend the curve" on electricity demand growth toward the lower end of the range of uncertainty.

Exhibit 8.3: Winter Peak Load Forecast



Validation

The Company benchmarked its demand assessment with the Commonwealth's 2050 CECP report. The baseline assumptions for the DERs in the Company assessment align with the targets in the CECP "All Options" Pathway and "Phased" Scenario as appropriate and available. In detail: (1) The heating electrification reaches the Company's share of the Commonwealth's "Phased" electrification scenario by 2050; (2) The transportation electrification follows the California Advanced Car and Advanced Truck rules, which have been adopted by the Commonwealth and align with the Commonwealth's "All Options" scenario policy target; (3) Solar PV adoption follows the "All Option" scenario (23 GW statewide), which is slightly lower than the more recent "Phased" scenario (27 GW statewide). The Company plans to incorporate the more recent scenario in its future annual load assessment release.; (4) Energy storage surpasses the Commonwealth's "All Option" scenario (3 GW statewide) and is close to the "Phased" scenario (5.8 GW statewide).

Overall, the Company's peak demand is expected to experience growth of 116% between 2020 and 2050, which aligns with the 100% expected growth shown in the CECP Pathways Analysis[3] during the same period. This validation with the CECP underscores the fact that significant investments in distribution infrastructure capacity are needed to meet the Commonwealth's clean energy goals.

Exhibit 8.4: Massachusetts 2050 Benchmark across Utilities in Base Case

Technology	State-wide Climate Benchmark*	National Grid 2050	Unitil 2050	Eversource 2050	Total Forecast
Solar PV (MW)	23,000 [1]	10,400 [3]	250	9,700	20,350
Energy Storage (MW)	3,000 [1] 5,800 [2]	2500 [3]	60	2,600	5,100
Electric Vehicles	5,400,000 [1]	2,700,000	53,000	2,700,000	5,453,000
Electric Heat Pumps	2,000,000 [1]	1,130,000	21,000	1,100,000	2,251,000

[1] From All Options Scenario
[2] From 2050 CECP Phased Scenario
[3] This is the total solar/storage expected to be in National Grid's territory. Only the portion that is considered "distributed" generation is included in the forecast.

8.1 Review of Assumptions and Comparisons across EDCs

The electric distribution companies (EDCs) in Massachusetts made up of Eversource, National Grid, and Unitil together have reviewed and compared overarching assumptions for future electric demand assessments across the Commonwealth. The overall forecasting strategies employed by each individual EDC share many similarities, especially with how they apply the impact of state--level clean energy scenarios.

All three EDCs develop DER scenarios from the different decarbonization pathways outlined in the Massachusetts 2050 Clean Energy and Climate Plan (CECP).[5]

[3] https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download

Exhibit 8.5: Forecasting Assumptions Across Utilities

Category	National Grid	Eversource	Unitil
Heating Electrification	Utilizes "Phased" scenario, "Full Electrification" scenario, and the "Hybrid" scenario	Utilizes "Phased" scenario, "Full Electrification" scenario, "Hybrid" scenario, "High Electrification" scenario, and "All Options"	"All Options" pathway
Energy Efficiency	Assumes Energy efficiency offerings continue at a slower rate to reflect market saturation and competition for funding with heat pump offerings.	Does not forecast Energy efficiency savings	Assumes Energy efficiency offerings continue in line with historic trends
Demand Response	Existing Company DR programs continue with growth	Simulates scenarios with 5% DR and no DR	Not considered
Solar PV	"All Options" pathway outlined in the 2050 Roadmap	"All Options" pathway outlined in the 2050 Roadmap	"All Options" pathway outlined in the 2050 Roadmap
Storage	Between "All Options" and "Phased" Scenarios.	"High Electrification" Scenario	"All Options" pathway outlined in the 2050 Roadmap
Transportation Electrification	Models load impacts of scenarios from adopting the California Advanced Clean Car (ACC II) Rule and Advanced Clean Truck Rule	EV baseline adoption rates from the 2050 MA CECP, with scenarios for moderate, high, ideal managed charging participation	"All Options" pathway outlined in the 2050 Roadmap

8.2 Buildings: Heating Electrification and Energy Efficiency Assumptions and Forecasts

Electrification of Heat (EH) and Energy Efficiency (EE) affect building electricity demand. The increased electrification of heating is one of the biggest contributors to load growth through 2050 and will cause winter peaks to surpass summer peaks in the late 2030s. These winter peaks are highest in the mornings and evenings when residential customers are beginning their days and then coming back from work. As discussed in Section 9, the Company's solution set for 2035 to 2050 needs to address this shift in peak load.

EE on the other hand will continue to offset peak demand, but at a slower rate of increase as the market becomes more saturated.

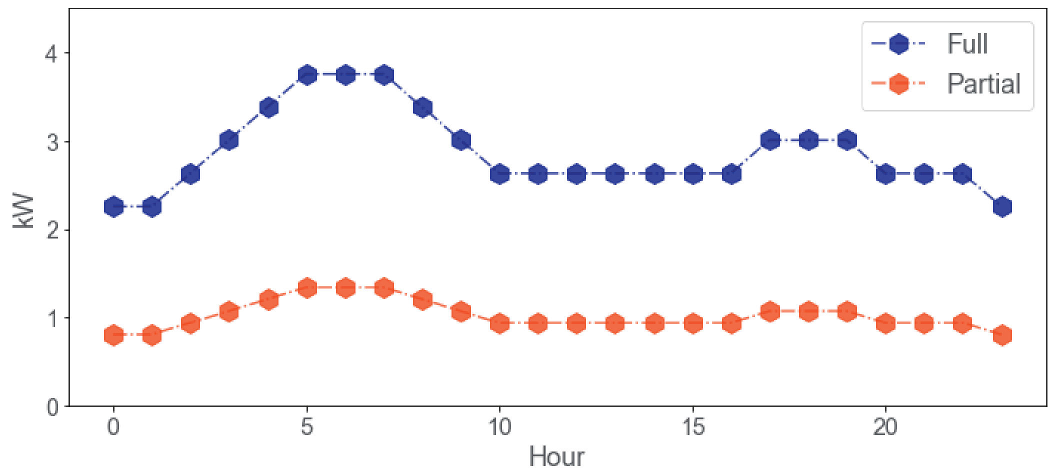
8.2.1 Technology Assumptions

To forecast demand associated with EH, the Company considers full Electric Heat Pump (EHP) systems and partial EHP systems. A full EHP system serves all the heating in the home or building. A partial or hybrid system utilizes alternative fuels during particularly cold temperatures. In these cases, customers will generally rely on gas/oil/propane-fueled heating systems (these systems may run on fossil fuels or clean fuels like renewable natural gas).

Load impact is calculated using the seasonal energy consumption of full and partial EHPs. Then, winter seasonal energy consumption is proportionally allocated to winter months (i.e., November to March) and some shoulder months (October, April, and May) based on a heating demand profile based on the Company's historical customer data.

The average load consumption profile for full and partial EHPs on a typical winter day is illustrated in Exhibit 8.6. Both profiles show a morning spike and a moderate evening increase reflecting the interactions of cold weather and customer behavior. The morning spike coincides with people rising in the morning and when the temperature tends to be lowest for the day, and the evening increase coincides with people arriving home in the evening. This profile is similar in shape and magnitude to ISO-NE's empirical study.[4]

Exhibit 8.6: Typical Winter Day for EHPs



8.2.2 Adoption Propensity Assumptions

The Company considers three EH scenarios (i.e., Base, Low, and High) modeling the trajectory towards meeting the Commonwealth's CECP "Phased", "Hybrid", and "Full Electrification" targets by 2050, respectively. The "Phased" scenario is the basis of the Commonwealth's GHG emission limits analysis because "it presents both long-term and near-term benefits over other building decarbonization approaches analyzed".[5] Thus, it is also adopted as the Company's Base case.

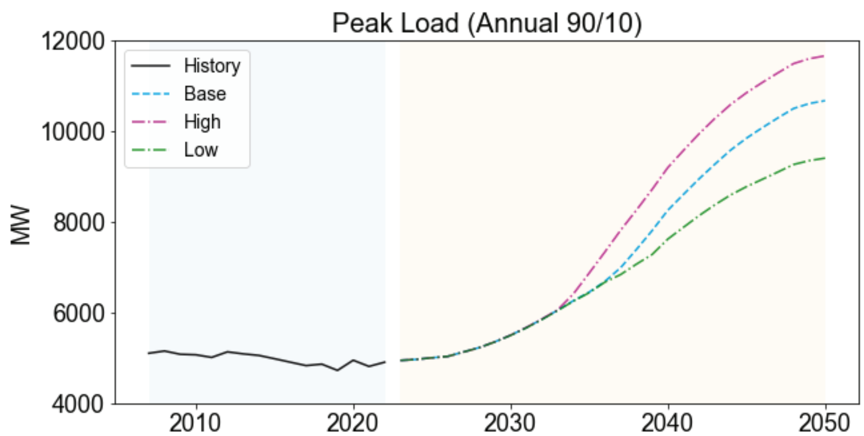
Exhibit 8.7: Electric Heating Forecast Scenarios

Scenario	Description
BASE	Partial and full EHP systems and allows for hybrid EHP systems aligning with the Commonwealth's assumption for the "**Phased"** scenario
LOW	Hybrid utilization of EHPs is more common, aligning with the Commonwealth's outlook for the "**Hybrid**" scenario
HIGH	Assumes more rapid adoption of full EHP systems and results in higher full EHP penetration through 2050, which aligns with the Commonwealth's assumption for the **"Full Electrification**" scenario

[4] https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf
[5] Massachusetts Clean Energy and Climate Plan, June 30, 2022, page 26

Exhibit 8.8 presents the estimated peak load under each of the Company's three heating electrification scenarios (with other DERs remaining the same). The uncertainty band grows wider further out in time, with the peak load varying up to about 2,200 MW or over 20% by year 2050. Nevertheless, even the modest electrification scenario indicates that the peak load nearly doubles between 2022 and 2050. In all EH scenarios, EHP adoption has minimal impact on short-term (2022 to 2034) forecasts as EHP adoption does not drive the shift to a winter-peaking system until the late 2030s.

Exhibit 8.8: Estimated Peak Demand by Heat Pump Adoption Scenario



It is also important to consider EE and the impacts it will have on heating peak demand. EE will continue to grow but at a slower incremental rate, reflecting the saturation of the market and uncertainties regarding available funding and supportive policies. There are no existing long-term quantitative Commonwealth policy goals for EE development. Thus, scenario development is largely based on known policies and programs and assumes a relatively flat growth in the residential sector and a slow-down in commercial sector due to market saturation and competition for funding with EH programs. Overall, EE penetration is expected to follow load distribution.

8.2.3 Building Code Assumptions

The Company's demand assessment does not explicitly model building code changes. However, the historical evolution of building codes to become more energy efficient is captured in the underlying econometric baseload forecast. Moreover, in a winter peaking future electricity system, the impact of building code upgrades will be primarily on demand from EH – and building weatherization is already captured in the Company's forecasting assumptions for EHPs. Nonetheless, as Commonwealth building code policies promote more energy efficient buildings and the electrification of buildings, the Company will actively focus on modeling the impacts of building code changes more explicitly.

8.2.4 Demand Response Scenarios – Impacts on Heating Demand

As explained in Section 8.2.2 above, the Company's demand assessment includes scenarios with varying levels of hybrid heating. Hybrid heating that relies on non-electric heating sources during periods of high electric demand can materially mitigate the impact of EH on peak demand. Beyond modeling the effect of hybrid heating, the Company currently does not have a demand assessment scenario that models managing electric heating demand. This is owing to a relative lack of industry experience and data for estimating the potential and reliability of other forms of electric heating DER during the coldest hours for which the Company plans its network.

There may be opportunities to manage peak electric heating demand in the future, such as through direct load control of heat pumps, thermostat control, or thermal ESS. However, industry activity and data on this front are limited and often from outside of the United States. The Company faces unknowns regarding customers' behavior on the coldest days in response to DR, price signals or load controls, the potential "snapback" effect, and the performance of EHPs under different conditions. Nonetheless, facing the prospect of very large winter peak demand in the future, industry activity on EH DER appears to be increasing globally. The Company will monitor the market evolution and seek representative (in sample size, diversity, and historical length) sample data (e.g., AMI data) for studying demand-side management opportunities from EH.

8.3 Transport: Electric Vehicle Assumptions and Forecasts

The load assessment process considers the impact of EVs as the largest contributor to peak load growth through 2050. Since users typically charge EVs when they return from work in the evening, EVs will contribute to a larger evening peak (subject to adjustments due to demand response programs).

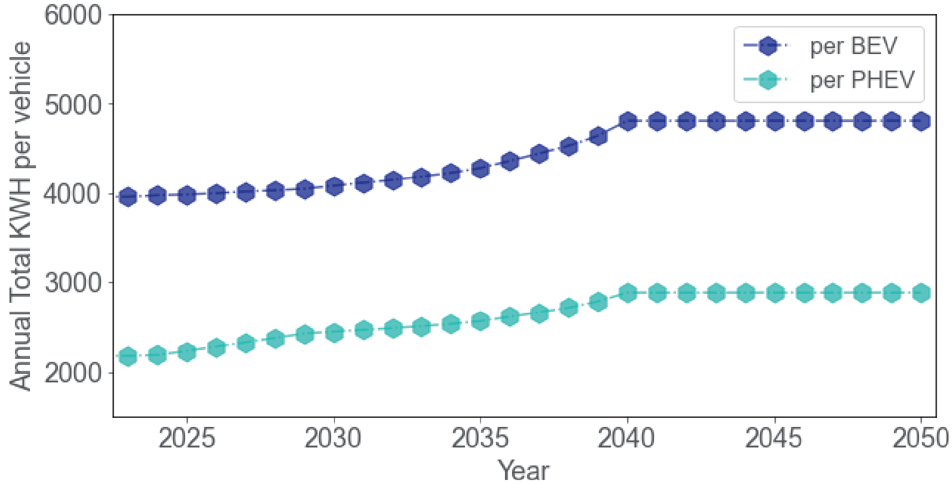
8.3.1 Technology Assumptions

The load assessment process considers the impact of EVs that plug-in to the electric system, including "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). Light-duty EVs (LDEV), medium-duty EVs (MDEV), heavy-duty (HDEV) electric vehicles and electric buses (E-buses) are the four categories of EVs modeled in the demand assessment.

As LDEV adoption rates increase, the annual energy demand associated with these vehicles, which is primarily determined by the vehicle miles traveled (VMT), also shifts. Exhibit 8.5 shows the temporal progression of the energy demand per LDEVs in kWh through 2050 using data from the National Highway Traffic Safety Administration (NHTSA).[6] The VMT-driven annual demand steadily increases until 2040 and remains stable after that.

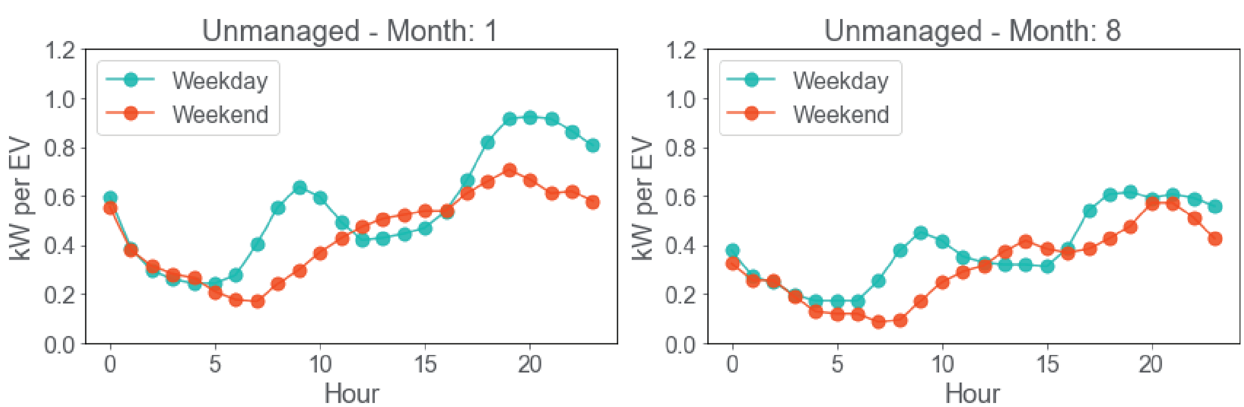
[6] https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952, retrieved July 2022

Exhibit 8.9: Temporal Progression of Energy Demand per LDEV



The Company's assumptions regarding the temporal pattern of charging behavior leverages an ISO-NE study.[7] Exhibit 8.10 depicts the unmanaged charging profiles of LDEVs for typical winter and summer days. A dual peak pattern is observed on weekdays with the evening peaks (between hours 19 and 21) generally larger than the morning peaks.

Exhibit 8.10: Unmanaged Charging Profiles



8.3.2 Adoption Propensity Assumptions

The LDEV adoption is modeled based on the Commonwealth's adoption of California's ACC-II Rule. Although the Rule requires 100% Zero Emissions Vehicle (ZEV) sales by 2035, it also offers flexibilities to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to encourage the sale of affordable EVs in EJCs, and the option to use historical ZEV sales credits to meet the annual ZEV sales targets. These flexible options provided in the rules expire by the year 2031.

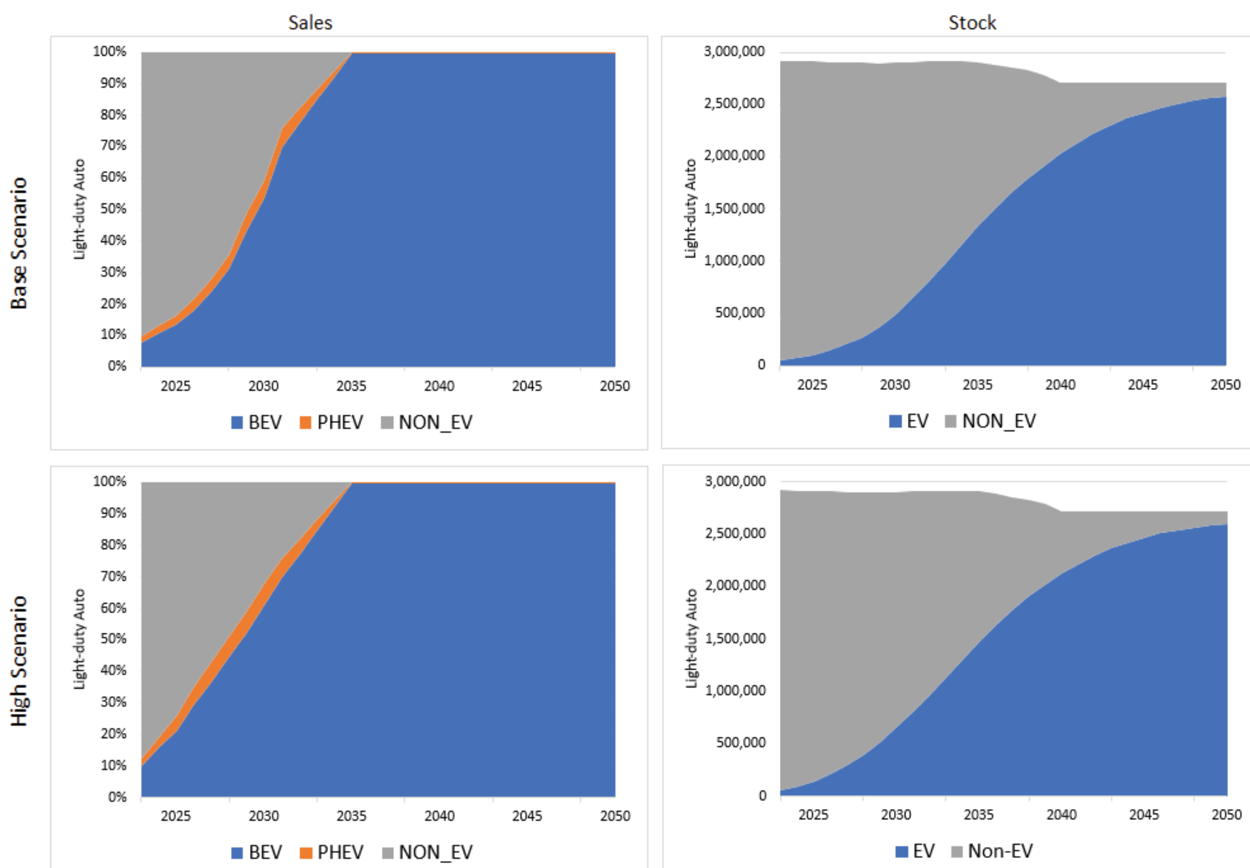
[7] https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf

These differences (i.e., with and without the flexibility) may lead to different ZEV sales patterns in the near term versus the longer term. The Company evaluates these two scenarios of LDEV adoption – one with the flexibilities (i.e., Base Scenario) and the other without the flexibilities (i.e., High Scenario) as presented in Exhibit 8.11. By the year 2050, both scenarios reach over 95% of EV penetration in the Company's Massachusetts service area, which aligns with the Commonwealth's CECP pathways.[13]

Exhibit 8.11: Electric Vehicle Forecast Scenarios

Scenario	LDV	MHDEV
BASE	With California's ACC-II Rule transfer flexibilities	Based on Commonwealth's adoption of California's ACT Rule
LOW	None	Based on Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook
HIGH	Without California's ACC-II Rule transfer flexibilities	Reflects an accelerated adoption rate

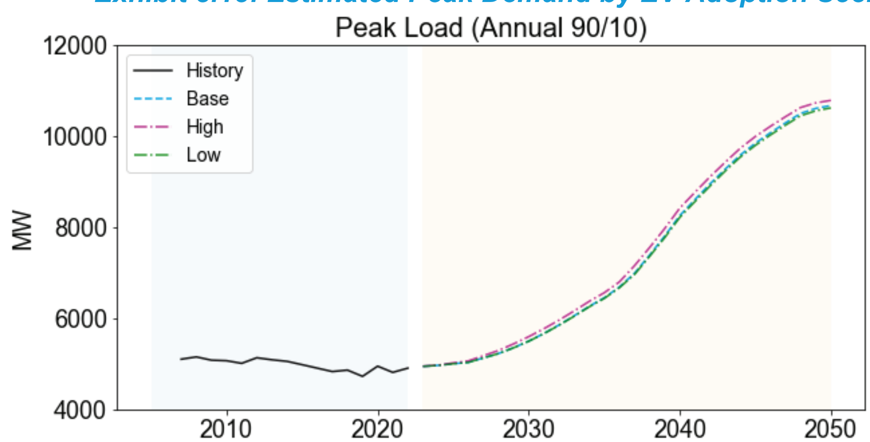
Exhibit 8.12: LDEV Adoption Scenarios



As of 2022, there are very few MHDEVs and electric buses in the Company's service territory. Because the MHDEV market is much more nascent than the market for LDEVs, there are greater uncertainties in projecting the adoption of MHDEVs and electric buses. Three different scenarios are developed for evaluating possible MHDEV and E-bus pathways: (1) the Base scenario is based on the Commonwealth's adoption of California's ACT Rule; (2) the High scenario reflects an accelerated adoption rate; and (3) the Low scenario is based on the Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook. The penetration ranges from 40% to 100% across scenarios and vehicle types by 2050.

Although these scenarios lead to different outlooks on EV adoption, the peak load impacts are similar to those presented in Exhibit 8.13. This is because: (1) the two LDEV scenarios have only slightly different adoption outlooks in the near-term but have very similar cumulative adoption overall as presented in Exhibit 8.13 (LDEV adoption scenarios); and (2) although the MHDEV adoption varies more across scenarios, the peak hour for the overall demand is expected to be in the evening through the assessment period, which does not coincide with MHDEV peak charging demand. Thus, the difference in total peak EV charging load between the scenarios is relatively small.

Exhibit 8.13: Estimated Peak Demand by EV Adoption Scenario



8.3.3 Mileage, and Time of Day Assumptions

Please refer to Section 8.2.1 Technology assumption.

8.3.4 Managed Charging Scenarios – Impacts on EV Demand

The Company's demand assessment includes a managed charging scenario that assumes 75% of LDEV owners have access to home chargers, and 75% of those LDEV owners are assumed to shift their charging demand to the hours immediately following the peak periods (i.e., from 16:00 to 22:00). Away-from-home charging is assumed to remain unmanaged. The managed charging scenario was developed based on the Company's current managed charging program and the National Renewable Energy Laboratory (NREL) EVI-Pro tool.[8] Under this EV charging demand flexibility scenario, the peak load demand is assessed to be reduced by 3.5% by year 2050 as a result of managed charging.

[8] https://www.nrel.gov/transportation/evi-pro.html

8.4 DERs: Photovoltaic and Energy Storage Systems – State Incentive Driven Assumptions and Forecasts

DERs such as Solar PV and Energy Storage Systems (ESS) are expected to have offsetting effects on peak load. However, due to the shift in peak demand from summer afternoons to winter evenings, (when there is little sun), the offsetting effect of Solar PV is minimal in the long-term forecasts. ESS are forecasted to help alleviate peak load, as they can store energy to be dispatched to the grid during adjusted peak load hours.

8.4.1 Technology Assumptions

The Company's demand assessment includes rooftop and ground-mounted PV types as outlined in the "All-Options" scenario in the 2050 Roadmap. The Commonwealth's decarbonization targets drive the Company's outlook on solar PV and ESS development in its service territory. The Company uses in-queue projects, customer demographic information, and the GridTwin[9] tool in estimating where and when projects may get developed.

8.4.2 Adoption Propensity Assumptions

The "Base" PV forecasts are projected to achieve the Company's share[10] of the Commonwealth's target under the "All Options" scenario from the 2050 Roadmap,[11] as shown in Exhibit 8.14. The forecasted 2050 distribution of ground-mounted PV and rooftop PV are illustrated in Exhibit 8.14 and Exhibit 8.15 below.

Exhibit 8.14: 2050 State-wide Targets and National Grid Solar Forecast

Technology	State-wide Climate Target (All Options)	Total 2050 Forecast for National Grid Service Territory	DG acting as Distributed Resource[12] in National Grid 2050 Forecast
Behind the Meter	6.99 GW	3.1 GW	3.1 GW
Ground Mounted	16.2 GW	7.3 GW	3.6 GW

The Company modeled two alternative scenarios that reach the "All-Options" scenario policy goal a few years earlier ("High") or later ("Low") to account for uncertainties. Nevertheless, once the system shifts to winter peaking by the late 2030s when the peak hour is expected to be in the late evening, PV is not expected to help reduce peak demand.

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[9] https://home.gridtwin.com/

[10] 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the Commonwealth compared with Eversource and Unitil. This same share is assumed for calculating National Grid's share of the Commonwealth's existing and planned solar goals.

[11] *Massachusetts 2050 Decarbonization Roadmap*, December 2020

[12] DG acting as distributed resources refers to DG that reduces the electric demand (vs. those acting as supply) thus should be considered for load assessment.

Exhibit 8.15: Solar PV Forecast Scenarios

Scenarios	PV
BASE	Base scenario models about 3.1 GW of BTM PV and 3.6 GW of ground-mounted PV
LOW	Reaching the "**All-Options**" scenario policy goal a few years later
HIGH	Reaching the "**All-Options**" scenario policy goal a few years earlier

Exhibit 8.16: 2050 Ground-mounted PV Forecast Heatmap under Baseline Scenarios

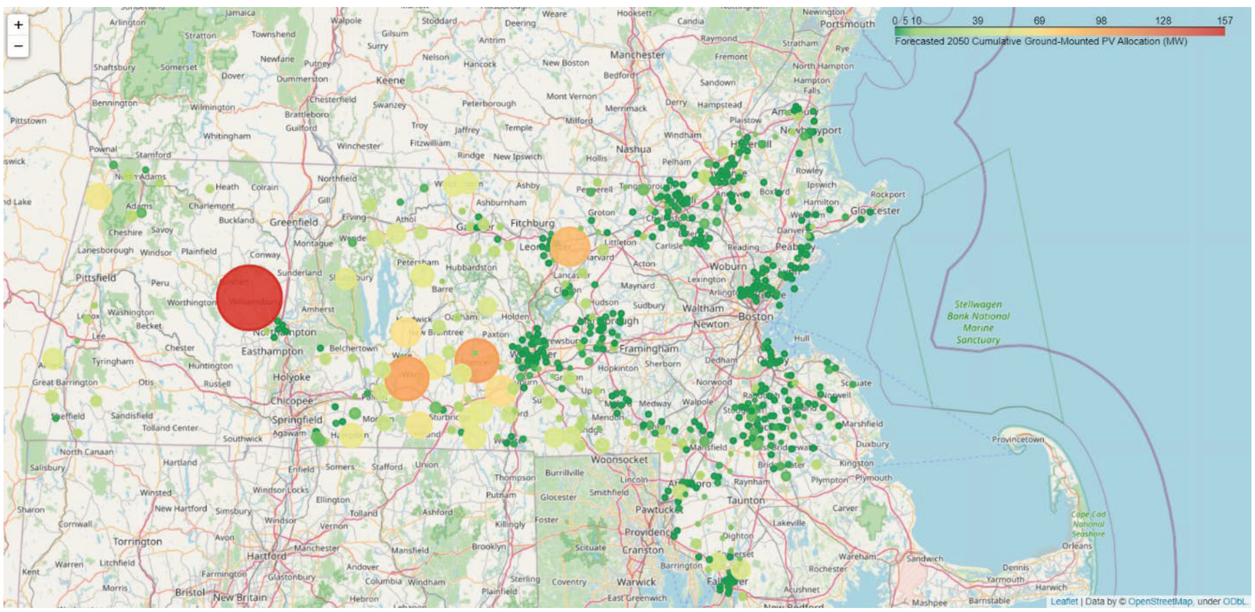
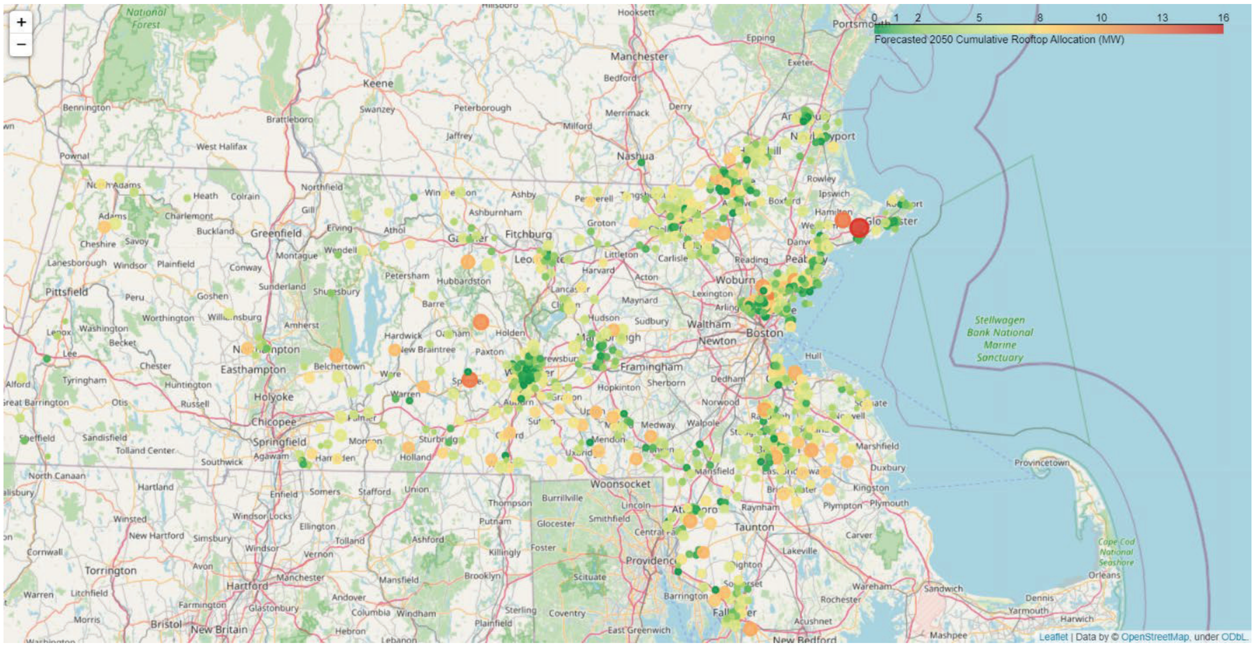


Exhibit 8.17: 2050 Rooftop PV Forecast Heatmap under Baseline Scenarios



The ESS scenarios were similarly developed using Commonwealth policy targets from the 2050 Roadmap, with assumptions around the Company's share[13] of the statewide target.[14] The "Base" scenario targets 1,000 MW of statewide ESS connection by 2025.[15] The 2050 Roadmap also identifies a few other ESS pathways through 2050, including reaching 3,000 MW of large-scale ESS (generation) in the "All-Options" scenario, about 4,000 MW in the 100% "Renewable" scenario, and about 12,000 MW in the "No Thermal" scenario. In addition, in the CECP, the "Phased" scenario identifies a pathway to reach 5,800 MW ESS Statewide.

Scenario	Description
BASE	Incorporates the 2050 Roadmap's goal of 1,000 MW of statewide ESS connected by 2025 and 3,000 MW by 2050
LOW	Considers the case of later and smaller saturation on the distribution level ESS market
HIGH	Considers the case of more of the total ESS capacity interconnecting to the bulk transmission as opposed to the distribution system

Most of the ESS in the Commonwealth is expected to be a resource for the wholesale market and thus not distributed generation and therefore out of scope for the Company's distribution network load assessment. Overall, under the Base scenario, ESS as a distributed resource is expected to continue grow in the Company's Massachusetts service territory but at a slower rate due to policy and market uncertainties. Two alternative scenarios were developed to (1) consider the case of later and smaller saturation on the distribution-level ESS market and (2) consider the case of more of the total ESS capacity interconnecting as wholesale resources as opposed to the distributed resources.

[13] Same as the PV share in the long-run.
[14] About 36% on the distribution system as of today.
[15] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*. Page 61, December 2020.

8.4.3 Time of Day Assumptions

The hourly impact of PV is simulated using the PVWatts tool[16] developed by NREL. On a sunny summer day, PV generation is expected to follow a bell-curve with maximum generation around noon, but the exact profile depends on available sunlight and temperature at the location. The solar PV generation profile is simulated with weather data for a typical meteorological year.[17]

ESS is modeled to discharge during typical peak hour window (15:00/16:00 to 19:00/20:00 for summer and 17:00 to 20:00 for winter) and charge at other hours (primarily during daytime to coincide with PV generation hours).

8.5 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 developing equitable workforce opportunities and limiting negative environmental and socioeconomic impacts.

On August 23, 2023, Massachusetts Department of Public Utilities (DPU) approved the Commonwealth's fourth round of offshore wind solicitations intending to procure at least 400 MW and up to 3,600 MW of offshore wind.[18] Several analyses have shown that offshore wind will be the linchpin of Massachusetts' decarbonization strategy – it will likely provide around 50% of the Commonwealth's power by 2050. Integrating offshore wind effectively and efficiently will require meaningful collaboration with other New England states. Massachusetts is well-positioned to lead this regional collaboration on offshore wind as the Commonwealth looks toward its decarbonized future.

Brayton Point in southeastern MA is one of the major locations where offshore wind energy is expected to come ashore. The Company has proposed a project to expand transmission infrastructure at Brayton Point and Grand Army to enable the interconnection of more offshore wind. The project will enable cost-effective integration of energy without significant disruption of local communities. Some of the benefits of the Brayton Point project include:

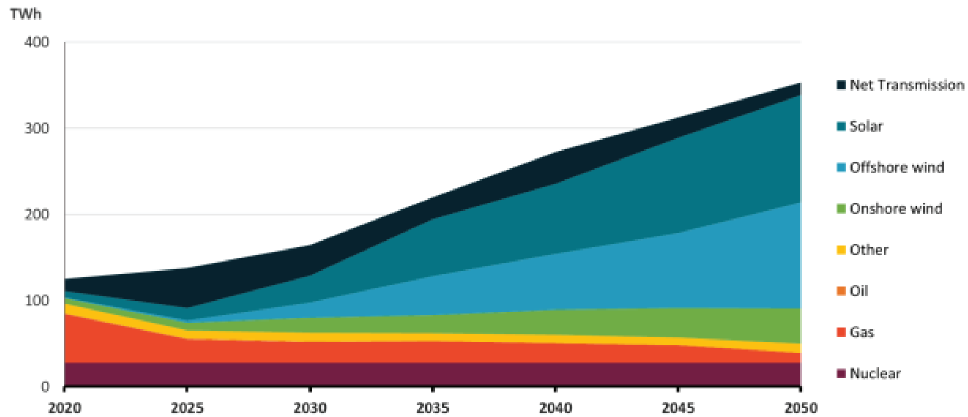
- Creating several hundred clean energy industry jobs;
- Alleviating transmission capacity constraints and congestion to allow the integration of clean energy (I.e., offshore wind);
- Avoiding the need to build infrastructure in a new location, including the need to secure new permits and engage in siting, by instead expanding and updating existing, former fossil fuel, infrastructure;
- Creating opportunities for future clean energy investments at the location; and
- Limiting disruption to local communities by building at existing Company facilities.

[16] https://pvwatts.nrel.gov/
[17] https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf
[18] D.P.U. 23-42.

8.6 Currently Projected Clean Energy Resource Mix

Most of the energy delivered to customers over the Company's electricity distribution network through 2050 will come from the bulk power system. That power will be increasingly decarbonized. Exhibit 8.18 below shows how the Commonwealth's 2050 CECP projects that New England's power grid will transition to will be dominated by wind and solar generation.

***Exhibit 8.18: New England's Electrical Generation by Energy Source*[19]**



Note: "Other" includes both biomass and municipal solid waste electric generation units.

[19] Mass CECP for 2050 – phased approach: https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download

Section 9

2035 - 2050 solution set – Building a decarbonized future

This section includes the Company's long-term vision for a decarbonized electric system, including a discussion of potential future network investments, enabling technology, programs, and policies.

Key Take-Aways

- As electrification scales up, the Company will connect EHPs, public and private EVs, ES, and renewables at an ever-faster rate. Annual peak load will increase and the widespread adoption of EH will result in a switch from summer to winter peaking around 2036.
- The Company expects to deploy more advanced and widespread load flexibility for buildings, EVs, and ES and better management for renewables through technology and pricing to provide NWAs to manage system and local peaks without the need for infrastructure investment.
- The Company will be further transformed through the digitization of the network planning and O&M. This will allow for better engagement and services for customers, and more efficient and effective operation for the Company.

9.0 2035 - 2050 Solution Set – Building A Decarbonized Future

In Section 6, the Company highlighted the 5- and 10-year planning solutions that are primarily driven by forecasted peak load growth in each sub-region, discussed in Section 5. It included Electric Vehicle (EV) load growth and other Distributed Energy Resources (DER) adoption. In this timeframe, Electric Heating (EH) does not yet have a significant impact on the summer peaks. The 2035 to 2050 demand assessment described in Section 8 indicates that winter peak load, in alignment with the 2050 Decarbonization Roadmap, will grow more than double between today and 2050. Furthermore, the system will shift from peaking on summer afternoons to winter evenings as early as 2035 in some regions. This Section will discuss the infrastructure, technology and policy solutions needed to meet long-term demand forecasts and realize a decarbonized future while maintaining safe, reliable, equitable service for all customers.

- **Accelerating Adoption:** From 2035-2050, electrification of heating and transportation along with decarbonizing the power supply will continue to be the primary strategies for achieving the Commonwealth's clean energy goals. It is estimated that peak demand will grow at an average annual rate of 3.4% between 2035 and 2050, surpassing the anticipated 2.5% annual growth between 2025 and 2034.
- **Supporting Customers through the Transition:** The Company will continue to support customers' transition to electric heating and transportation through incentives and enablement of electric heat pumps (EHPs), energy storage (ESS), electric vehicles (EVs), and associated programs, while also integrating growing amounts of solar and solar paired with storage.
- **Minimizing Costs:** Focus will continue to be on delivering the clean energy transition affordably. The Company will:
    - Deploy Non-Wire Alternatives (NWAs) where they provide value to customers to defer or avoid specific network infrastructure investments.
    - Prioritize Energy Efficiency (EE) and demand flexibility for buildings by deploying managed control of EHPs and Behind-the-Meter (BTM) ESS, including opt-in or opt-out customer control, third-party control (e.g., aggregators), or Company control.
    - Prioritize demand flexibility for EVs through deployment of managed charging and Vehicle to Grid (V2G) programs, including opt-in or opt-out customer control, third-party control (e.g., vehicle OEMs), or Company control.
- **Building Technology to Enable the Business:** The Company will deploy improved digital tools necessary to plan, construct, maintain, and operate the grid more efficiently and effectively. More digitally enabled devices connected to the electric network will be able to leverage software-as-an-asset to update devices remotely and will require continued investment in cybersecurity to ensure the secure operation of the system.
- **Focusing on the Needs of All Customers and Communities:** The Company will deliver a clean, fair, and affordable energy transition by building a smarter, stronger, cleaner electric grid for all.

These 2035 and 2050 planning solutions will be built off foundational grid investments made in the next 5 to 10 years (described in Chapter 6). As shown in Exhibit 9.1, the implementation of programs and technologies in the near-term will provide the Company with a foundation to build solutions in 2035 and beyond. For example, the Company intends to deploy solutions such as innovative programs that must first be tested through pilots or by reviewing other utilities' experiences. Furthermore, current programs that have been successful can be scaled up to meet load demand.

Furthermore, the Company will need to adjust its solution set for the next ESMP to account for the shift towards winter evening peaks. For example, Solar PV will be less effective in offsetting future peak demand because the peak is projected occur on darker winter evenings; properly controlled and operated energy storage could be deployed to shift PV contribution to align with peak needs or to otherwise offset peak demand. Demand response (DR) programs will need to continuously evaluate peak hour forecasts and adjust the times they request customers to turn off appliances. The effectiveness of these DR programs will depend on the technology deployed. DR programs for EVs could specifically help offset the evening peaks if designed effectively, as many EVs are charged in the evenings. On the other hand, it is uncertain how much DR programs involving EHPs could offset peak load, as customers may have varying degrees of willingness to turn off heating during the coldest winter days. As the Company reviews each 2035 to 2050 solution set, we will discuss any relevant impact or necessary adjustments in relation to this new peaking pattern.

Exhibit 9.1: Illustration of 2035 to 2050 Solution Set

The investments proposed in this Future Grid Plan will empower our customers and communities throughout Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future....

.... and enable customer adoption of clean, electrified technologies to drive down greenhouse gas emissions while improving their energy experience.

Improving comfort and convenience 1
Before Tina comes home, her house is cooled to a pre-set temperature so it's comfortable for her when she arrives.

Optimizing battery and solar to provide resources and value 2 3 4
Tina settles in and does a load of laundry 2. Given peak demand conditions, with other neighbors also coming home, her battery 3 in the garage cycles on and off based on solar panels 4 from her roof and grid conditions (charging and discharging where optimal) to offset those costs.

Saving money and reducing peak demand 2 5
Tina just finished dinner and loaded the dishwasher 5. Tina's dishwasher and dryer 2 start automatically when electric prices are lowest to optimize her bill and her demand on the grid.

Filling the "tank" at the lowest cost and carbon footprint 3
While Tina is sleeping, car charging 3 is actively managed based on grid conditions, and will be fully charged when she needs it in the morning for work.

Leveraging innovation to save energy and money 6
Tina's home and the grid talk to each other constantly. With her permission, extra energy can be sent back to the grid, allowing her to potentially earn money from her solar panels. Alternatively, when Tina needs extra power, her devices are managed so well that they will allow her to avoid a costly service transformer upgrade.

9.1 Clean Energy Solutions Including Behind the Meter Incentive Design Scenarios

The Company will continue to listen to and adjust offerings to meet customer needs. By 2028, the Company plans to have Advanced Metering Infrastructure (AMI) deployed across its service territory. This would allow the Company to fully leverage meter data for granular information on customer energy use patterns, clean technology adoption, and program engagement. Residential and commercial customer surveys will continue to be conducted to learn about perceptions, awareness, barriers, and preferences. Focus groups, direct customer feedback, and community listening sessions will be held to develop deeper insights by customer segment. With improved customer data, the Company can better tailor products and programs in response to customer needs. The Company will be able to tailor programs to help customers reduce energy costs based on specific customer profiles. For example, customers can be targeted for behavior-based energy conservation programs based on the amount and timing of a customer's energy use.

The Company will continue to build on BTM programs such as EE, DR, flexible connections, EV and ESS managed charging, and Time Varying Rates (TVR). To understand the full benefits of DERs, the Company is collaborating with MassCEC, Baringa, and Eversource to study the potential value that dispatchable DER flexibility products can create for customers and the grid. This research involves analyzing data and facilitating discussions with peer utilities, aggregators, flexibility marketplace providers, and technology OEMs.[1]

9.1.1 Buildings: Winter Demand Response Scenarios

In the 2035-2050 timeframe, the electric system is expected to shift from summer peaking to winter peaking. Correspondingly, peak load will shift from being driven primarily by air conditioning load on the hottest summer days, to being driven by electric heating load on the coldest winter days. The Company currently does not include winter DR scenarios in its demand assessment, due to the lack of industry experience and data on responsiveness to electric heating DR on these coldest days (see Section 8.2.4). Despite this uncertainty, the Company acknowledges that there likely will be an important role for demand side measures to help reduce winter peak demand.

The Company expects to address the increasing electrification of load through two methods which will help manage demand:

1. Continued deployment of EE measures (e.g., weatherization and appliance upgrades) to minimize overall peak demand growth, as the Company does today as a Mass Save Program Administrator.[2]
2. The demand flexibility for building programs that leverage TVR, DERMS, communications, and streamlined customer billing. These programs will be initially deployed in 2025-2034 and are anticipated to be effective tools in helping the Company induce customer behaviors to flatten load curves and reduce increases in peak electric demand.

[1] https://www.masscec.com/grid-modernization-and-infrastructure-planning. Initial findings from the study were presented at the August 10, 2023 GMAC meeting https://www.mass.gov/doc/gmac-meeting-presentation-slides-08102023/download

[2] On March 26, 2021, Governor Baker signed into law Chapter 8 of the Acts of 2021, An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (the Climate Act), codifying the Administration's commitment to achieve Net Zero emissions in 2050 and furthering the Commonwealth's nation-leading efforts to combat climate change and protect vulnerable communities. The 2021 Climate Act established new mandates for GHG emissions reductions by 2030 and 2040 and directed the EEA Secretary to set a GHG emissions reduction goal for three-year Energy Efficiency Plans.

While summer DR has been successful, the winter events have fundamentally distinct characteristics that make DR more challenging.[3] These will need careful studying. Some potential ways to manage winter heating loads include:

- Use of battery storage including V2G, or
- Switching to non-electric alternative heating sources such as natural gas, low carbon gases (e.g., renewable natural gas, hydrogen), delivered fuel, biomass (e.g., wood), or back-up diesel generation.

The adoption of these approaches will present challenges, and steps must be taken over the next decade to address them. For the time being, switching to non-electric alternative heating sources may offer the best intermediary solution to system peak on the coldest days, as many residential and commercial buildings are likely to be remain “hybrid” (i.e., having both electric heat pumps and a legacy heating system such as natural gas) through this period of transition.

9.1.2 Transport: Electric Vehicle Charging Demand Management Scenarios

Charge management for EVs remains an area of high importance and a growing capability, yet challenges remain to ensure that its potential positive impact is achieved. Managed charging programs that are poorly timed run the risk of worsening grid conditions. Effective load management techniques also need to consider the charging customer’s needs and preferences.

Managing EV charging can take several forms. On-site load management, load balancing, or load-offsetting techniques can potentially apply to any EV charging site. For customers who are flexible as to when their EV charging occurs, (e.g., most residential customers), there are two main types of managed EV charging: Customer-driven EV charge scheduling (or “passive” managed charging), and dynamic charge management based upon signals for grid conditions or costs, (or “active” managed charging).

Passive managed charging programs focus on incentivizing customers to change their own charging behavior. While passive programs are simple in design and easy to administer, they may not be as effective or robust as active programs since they rely on human behavior. These programs are generally designed as blunt instruments to attract customer participation at scale. The benefit of these programs may be to achieve overarching system demand management, but they are not effective mechanisms to manage real time locational grid congestion constraints. These programs are designed to function more as ‘set it and forget it’ and their associated economic benefits are lower than more dynamic managed charging offerings.

Examples of passive managed charging programs are time-of-use rates or specific incentive design

[3] Winter DR programs face significant challenges. Firstly, the temperature difference between outdoor and indoor air temperatures during a winter peaking event, which occurs during the coldest hours of the day, is much larger than the temperature differential during a summer peaking event. For example, during a winter peak an outdoor air temperature of -5 degrees is a difference of 73 degrees from an indoor set point of 68. In the summer, by contrast, an outdoor air temperature of 95 degrees is only 20 degrees away from an indoor set point of 75. Therefore, the rate at which the indoor temperature would drop during a winter DR event would be 3-4 times higher than the rate at which the indoor temperature would increase in the summer. During the summer events, many homes can “coast” for the duration of the DR event, slowly rising in temperature to a maximum temperature as defined by the customer, only turning the air conditioner back on at the end of the event. Since the outdoor air temperature will have dropped markedly during the event, typical dispatch periods are 5-8pm, the air conditioners do not have to work as hard to return the home to temperature at the end of the event, and the magnitude of that load reappearing on the grid will not be as impactful as it would have been had they been operating during the time of the systemwide peak. Conversely, for a winter event, the home’s temperature is likely to drop below the minimum value specified by the customer well before the end of the event. As a result, when the EHP turns back on after only 1-2 hours, the grid would still be within the period of the peak. Therefore, with current design parameters an electric heating DR event would have the impact of shifting the peak later but not meaningfully reducing it.

programs that reward off-peak charging. For example, a passive program may currently offer incentives for charging between 8pm and 5am. As the shift to a winter morning peak occurs, these passive program designs may need to shift to earlier in the evening to not conflict with higher winter peaks coinciding with customers needing to drive out of their homes to get to work in the morning. This illustrates why program designs need to be developed in close concert with system demand shifts over time. Nevertheless, time-of-use rates may influence customer behavior over time which may ultimately enable more informed decisions between the EDCs and customers.

Active managed charging programs on the other hand provide utilities or a market aggregator working with charging networks, the tools to meaningfully impact locational demand – and therefore potentially ameliorate associated grid upgrades – subject to customer opt-outs. Active programs have the capability to directly control charging time, scale, and location, to achieve a variety of outcomes, such as managing peaks, absorbing excess renewable generation, or supplying some ancillary services to a structured market. These programs rely on a reliable two-way flow of information that includes 1) a transport layer that relies on a communication signal via Wi-Fi, cellular, vehicle telematics, etc. to send the charging instructions and 2) a messaging protocol or standard that can help the device understand and execute the instructions.

Active and passive programs can work in concert with one another. Customers on time-of-use rates could opt into active programs to help them minimize their charging costs without them having to think about it. According to a 2021 report by NREL[4] that cited DOE research, 80% of EV charging occurs at home due to the convenience and low cost of residential charging. That trend is expected to continue with increased EV adoption, thus elevating the importance of programs designed to manage home charging.

The potential for managed charging varies by sector and charge type.

Residential at-home charging: This is the most promising current application, as most customers plug in when they get home and remain plugged in overnight. The long dwell time means that there is a high amount of flexibility for changing when the charging happens. However, activation of the charging must be done carefully to avoid creating a new local peak. For example, a residential program that prevents charging from 3pm-8pm but allows all vehicles to begin charging at full speed at 8pm would result in higher total system peaks than if each car had simply begun charging when it arrived home (See the modeling presented in Section 8.1.3). Furthermore, the optimal charge patterns on any given circuit are dependent on local system conditions (e.g., sub-regions with high PV on the system have entirely different load constraints than sub-regions with no distributed PV). The Company is working to address these issues with its program design.

Workplace charging: With the anticipated prevalence of home charging and hybrid work schedules continuing for a majority of customers, workplace charge management is expected to be applicable to limited customer segments. Given the moderate dwell times and repeat nature of users of these charging stations, there is some potential for managed charging at workplaces, especially as most workplaces will have demand rates with the EDCs and thus their own intrinsic desire to manage their charging. However, balancing the needs of the charging customer will be paramount. Customers must be assured they can reach a given level of charge by a certain time. Approaches will also have to be regionally specific depending on the amount of solar or other load on the system.

Public charging: This segment is not well-suited for load management programs due to the demand being inelastic. A driver who utilizes a charger at a highway rest stop, for example, does not have flexibility to change their charging behavior. One possibility for managing these loads is on-site batteries that can be charged and discharged in such a way as to flatten the overall load. The

[4] https://www.nrel.gov/docs/fy21osti/78540.pdf

company expects these types of solutions to continue to develop over the next decade.

Fleet charging: While the residential market segment has the most managed EV charging engagement today, fleets have the potential to create the most local grid value in the future. The Company has begun early engagement with Medium and Heavy Duty (MHDEV) fleet operators looking to electrify. Appropriate charging of these fleets will be key to minimizing impact to both the grid and the customer's business operations. Thoughtful collaboration between the utility and fleet operators that considers existing routes, duty cycles, and load management potential when siting EV chargers can help to minimize upfront installation and ongoing operational costs.

Because MHDEV electrification represents a potentially large increase in a customer's electric bill, it is anticipated that large fleet customers will have an interest in managing their demand. Customers who are already high consumers of energy will be familiar with the concept of demand management and may pursue EV Energy Management Systems (EMS) or load balancing software for fleets on their own. The incremental benefit that could be gained from layering a fleet managed charging program on top of charge management software that customers may install should be examined.

However, it is anticipated that electric demand management will be a new concept for many EV fleet customers used to managing costs associated with a different fuel resource (i.e., diesel). In the case of a small depot, their previous electric consumption may have only consisted of a small building and overhead parking light. Hence, the Company expects that a significant amount of education around EV charging optimization and overall demand management will be required for operators of newly electrified fleets.

Depending on the size and location of the fleet loads, it may make sense to work with customers on a case-by-case basis to develop a charge management solution that meets both the customer and local grid needs as opposed to a program that attempts to target fleets collectively. Vehicle-to-Everything (V2X) systems of all types may be able to contribute to alleviating the peak if bidirectional charging capabilities continue to develop and appropriate contractual arrangements can be made with customers. This is a nascent industry, however, and the exact nature and magnitude of this potential remains unknown. Technology and safety protocols needed to support the successful delivery of such solutions at scale are still being developed. As of summer 2023, only a handful of chargers and EVs with bidirectional capability are approved for use in the United States. Current V2X functionality falls into three types discussed below.

Vehicle-to-Grid

V2G refers to systems in which EVs sell demand response services to the grid. This technology is an area of growing promise, especially as advancements in battery technology allow vehicle classes beyond light duty and school buses to electrify. For V2G to be a viable solution for providing system relief, standard bi-directional protocols and connectors must be developed in parallel. Strategic siting of MHDEV fleets with V2G capability could allow that fleet to play a role similar to a large battery in alleviating grid constraints. However, vehicles are mobile assets, hence the value provided by V2G is difficult to quantify even where the capability is known to exist. Reliability of those V2G assets will vary based on fleet type and will be governed by business operations, which will determine how often those vehicles can actually be plugged in and discharge or charge when needed.

Vehicle-to-Home (V2H)

In V2H applications, a customer's EV can be transferred to power a home or business rather than exporting energy to the grid. The ability for an EV to act similar to a battery system not only requires a compatible bidirectional charger and EV, but also special metering and equipment that allows for islanding. The extent to which customers pursue V2H as an alternative to a battery system for backup power during outage is unknown. However, such an application could potentially provide relief during times of high demand by serving local loads to prevent drawing power from the grid. As a general challenge, the time that the system would most need the discharge is for the early-morning peak, which directly contradicts customer goals of having fully charged vehicles ready to commute to work. If remote work continues to be the norm for many industries, there may be customers who are willing to participate but it is simply an unknown at this time.

Vehicle-to-Load (V2L)

V2L technology transfers power from the vehicle's battery to connected appliances and devices, and does not require a bidirectional charger to operate. Vehicles with V2L have a built-in bidirectional charger and standard AC power outlets that can be used to power essential household appliances, such as refrigerators, lights and laptop computers. While several EVs currently offer V2L functionality, V2L is unlikely to play a significant role in demand mitigation as the household loads that can be supported are relatively small. V2L can, however, play an important role in limiting customer inconvenience and dissatisfaction associated with outages of minimal durations.

The Company continues to monitor developments in V2G and assess whether additional value can be created by developing programs specifically targeted to this as an asset class as opposed to treating the different types of V2X as either an EV or a battery.

9.1.3 Other Load Management Response Scenarios

Existing load management programs encourage customers to curtail load or discharge batteries during peak times on the ISO-NE grid. The timing of ISO-NE system peaks is largely coincident with when distribution constraints occur. However, programs that were designed to target load shed at the ISO-NE level only, cannot serve all of the use cases where load management could be beneficial to the distribution system at a more localized level. Certain locations on the system may experience constraints outside of the typical ISO-NE peak windows, and additionally, those constraints may not be purely due to load. The Company is exploring ways to make demand-side resources firmer through alternative regulatory constructs, asset types, and program designs that will allow for increased customer opportunities to provide localized system relief.

As described in Section 6, the Company will leverage its DERMS, AMI, and ADMS investments to test new ways to procure load flexibility services from DER customers and/or aggregators that can more dynamically respond to grid constraints in specific locations. As those technologies and the accompanying capabilities mature (i.e., increased data and energy usage visibility, short-term forecasting, improved grid management and control), the Company will learn which flexibility procurement approaches work best (i.e., programmatic vs. market-based) and scale those to most effectively address a growing set of grid needs in 2035-2050.

9.1.4 Battery Storage Charge Management

Front of the Meter (FTM) Batteries

Large, FTM battery storage solutions come in two versions.

a. **Standalone Storage** is typically deployed as wholesale assets connected to the distribution system or by the EDC as NWAs (see Section 9.3). If the FTM storage is an NWA, it is under direct EDC control. The EDC will ensure that the storage does not contribute to a system peak and subsequent potential thermal overloads on the distribution system that would require upgrades to mitigate, but rather reduces it. On the flip side, wholesale assets require as much flexibility and available charge and discharge capabilities as possible to maximize their potential market profits. To enable wholesale assets to have as much flexibility without driving up system peak or contributing to system upgrades, the Company is offering customers the choice to interconnect these storage systems under Active Resource Integration (ARI) control. This flexible connection tool allows small- and large-scale DER customers to bypass the grid headroom requirement and enables the Company to actively limit storage operation based on real-time dynamic grid system conditions. DERMS, when implemented, will allow the Company to remotely monitor and operate storage.

b. **Co-sited with large solar storage solutions** aimed at reducing interconnection cost of solar sites by conducting peak shaving. These storage solutions absorb generation primarily from solar and discharge to the grid when no solar generation is available. In most cases, co-located storage never charges from the power grid, and depending on how the customer's system is designed, they may never discharge during peak solar generation. Solar and storage sites, especially EDC owned, can be considered under NWA dispatch, as discussed in Section 9.3.

More details on dispatching and controlling FTM storage systems can be found in Section 9.3.

BTM Batteries

Many customers are pursuing battery storage to meet their own reliability needs, or to manage demand charges. Customers currently can participate in the Company's ConnectedSolutions DR program which provides incentive payments for participating in peak DR events called by the Company.

Current DR programs compensate customers for discharging the batteries at times coincident with the ISO-NE peak. In the future, more sophisticated dispatch strategies may be needed to help address localized grid constraints and help balance load and BTM generation on circuits. With AMI and DERMS fully implemented, the EDCs would be well positioned to use BTM DERs in their operational control, to manage demand on the grid more effectively. An aggregator that contractually commits to delivering the needed MW may also provide this support.

Regulatory rules for participation in both wholesale and distribution level programs will define the market. As battery storage system costs decline and their value to grid services develop, it is expected that electric customers will more widely adopt batteries to meet their energy and resiliency needs and to provide services to the distribution system through a market mechanism. The Company will look to leverage this dispatchable BTM storage directly or through third parties to efficiently manage capacity.

9.2 Aggregate Substation Needs

There are network infrastructure projects needed beyond the 10-year planning horizon driven by electrification. Consistent with the ESMP planning process described in Section 6.4, the Company performed a review of projected substation transformer and feeder loading and identified capacity deficiencies which would detract from the distribution system's ability to support the Commonwealth's electrification goals in the 2035-2050 timeframe. High level solutions to address these deficiencies were developed, building upon the foundation established with the 10-year plans described in Section 6.

Due to the far-future nature of these capacity needs, the Company did not fully scope these investments and instead is providing an indicative summary detailing the number of major substation expansion or addition projects that it anticipates will be required in the 2035-2050 timeframe, based on this review. This is a preliminary view of the network reinforcement projects expected to be needed and is subject to change.

As part of its annual planning processes, and through each 5-year ESMP planning cycle, the Company will reassess and refine these plans in light of the latest available information, including the most recent forecast, localized loading trends (both through widespread electrification adoption and discrete electrification spot loads), DER adoption, and developing capabilities such as DERMS. All of these factors may result in modifications to the scope and scale of investments required to maintain pace with electrification adoption throughout the service territory.

The following sections summarize major themes across the sub-regions.

Central

To support electrification load growth in the Central sub-region, the Company has identified a preliminary list of 18 projects for the 2035-2050 timeframe, including five new substations and six major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments to convert the legacy Worcester backyards and High-Tension system to a distribution configuration more suited for modern needs. These distribution investments will enable the retirement of approximately nine 4.16 kV substations in the Worcester area.

Merrimack Valley

To support electrification load growth in the Merrimack Valley sub-region, the Company has identified a preliminary list of 13 projects for the 2035-2050 timeframe, including six new substations and six major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Chelmsford, Westford, North Lowell, Haverhill and Newburyport to relieve loading on the existing 23kV sub-transmission system.

North Shore

To support electrification load growth in the North Shore sub-region, the Company has identified a preliminary list of 15 projects for the 2035-2050 timeframe, including five new substations and nine major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Cape Ann area to relieve loading on the existing 23kV sub-transmission system, as well as radializing the existing Lynn secondary network system to be better suited to modern needs. These distribution investments will also enable the retirement of approximately seven 4.16 kV substations in this area.

South Shore

To support electrification load growth in the South Shore sub-region, the Company has identified a preliminary list of 16 projects for the 2035-2050 timeframe, including five new substations and 11 major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by expanding existing single transformer stations to provide additional capacity, while increasing reliability and resiliency.

Southeast

To support electrification load growth in the Southeast sub-region, the Company has identified a preliminary list of ten projects for the 2035-2050 timeframe, including four new substations and three major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending transmission closer to the load centers of Attleboro, Foxboro and Wrentham, to relieve loading on the existing Union Loop 23kV sub-transmission system.

Western

To support electrification load growth in the Western sub-region, the Company has identified a preliminary list of 14 projects for the 2035-2050 timeframe, including one new substation and nine major substation expansion projects. Additionally, the Company will continue to build on the 10-year investments by extending the transmission closer to the load centers of North Adams, Great Barrington, Sheffield, and Northampton to support load growth and relieve the 23kv sub-transmission system.

9.3 Non-Wire Alternatives – Impact on Substation Deferral

In this Section, the Company describes its approach to scale NWAs as an integral part of future network planning and operations.

As discussed in Section 6.4 and Section 6.11, the Company sees an important and growing role for NWAs to play in future network planning and operations. In particular, the Company plans to use its 5-year and 10-year investment period to test and hone its NWA capabilities, as well as to stimulate the market among flexibility service providers in Massachusetts, so that NWAs can be delivered reliably and cost-effectively at scale in the 2035-2050 period. This includes using the 2025-2034 period to develop the technology, regulatory frameworks, customer programs, rate design, and procurement mechanisms to scale existing NWA enabling efforts underway.

System-wide peak load reductions

As described in Chapter 5, the Company's load forecast, which planning teams rely on to evaluate the need for distribution network infrastructure investments, reflects the peak load reductions from various technologies and programs such as EE, DR, and solar PV. Without these subtractors, the system peak in all sub-regions would be significantly higher and would require that the Company implement earlier and more significant network infrastructure investments. These programs function as "system-wide" NWAs and are considered by the Company through its forecast and the adjustments made to the forecast.

1. **EE, DR, and EV managed charging programs**

   As noted in Section 4 and Section 6, the Company's network is supported by nation-leading Mass Save EE and DR programs which have helped offset peak load growth and reduce the need to expand network infrastructure considerably over the last decade. The Company also administers an EV off-peak charging rebate program, which helps to shift EV charging load outside of peak hours.

   In the 2035-2050 timeframe, the Company intends to scale and evolve these system-wide programs as both electric network and customer needs change and continue to leverage them to offset peak load growth and defer traditional wires-based network investment.

2. **Time-varying rates (TVR)**

   As described in Section 6.11, the Company also plans to begin testing and offering TVR in a phased approach within the immediate 5-year investment period alongside AMI deployment. In the 2035-2050 timeframe, the Company will have already achieved widescale deployment of both AMI and TVR and expects increased participation in TVR. In 2035 and beyond, customers will have the technological infrastructure, access to data, and ability to seamlessly interact with the Company and other third parties to have choice and control in how they want to support the smart use of the grid, pursue electrification, and reduce the overall costs of the energy transition. As more customers adopt TVR, the forecast will adjust to reflect the peak load reduction benefits across the network from TVR, which will help reduce and/or defer the need to deploy network infrastructure across the network.

Targeted NWAs

Section 6 includes the Company's proposal to buildout necessary technology enablers such as DERMs, ADMS, AMI and associated data and security investments (Section 6.3), as well as customer-facing programs (Section 6.11) to test how to best procure flexibility to meet the grid need in a specific location. The Company intends to develop and test the best ways to communicate with, monitor, control, dispatch, compensate, and procure flexible resources on the distribution network.

The Company will leverage a "test" and "scale" approach to learn quickly and maximize the potential of these NWAs to transform the way the Company operates and plans the network.

In the 2035-2050 timeframe, the Company envisions reaching a certain level of maturity for its NWA capabilities based on the learnings gathered over the preceding 5- and 10-year investment periods. In this future timeframe, the Company expects to have identified and scaled key best practices, as well as transformed the network planning and operations processes to more fluidly embed NWAs as agile solutions that can be used to meet a variety of grid needs across different locations. This of course will be dependent on the learnings gathered over the next several years, though there inevitably is an important growing role to leverage NWAs tactically to offer more affordable and reliable options for Company customers, where possible.

9.4 System Optimization – Impacts on Electrification Demand

Investment in digital, data and IT systems from 2025-2034, including DERMS, AMI, ADMS, ARI, and communications infrastructure, will allow the Company to more actively and flexibly manage load and deliver improved electric network system optimization for all Company customers. The Company will continue to leverage those foundational investments to evolve system optimization programs during the 2035-2050 period.

9.5 Alternative Cost-Allocation and Financing Scenarios – Impact on Investments

See Section 7.1.2. In addition, the Company will pursue future alternative financing opportunities that may emerge circa 2035 and beyond (e.g., from new federal legislation).

9.5.1 CIP 2.0 (Solar) Projects and Cost Allocation

See Section 7.1.2.

9.5.2 CIP 3.0 (Battery Storage) Projects and Cost Allocation

See Section 7.1.2.

9.6 Enabling the Just Transition Through Policy, Technology, and Infrastructure Innovation

The Company is committed to delivering a clean, equitable, and affordable energy future for all our customers. In addition to ensuring that the customers and communities served have equitable access to safe and reliable energy services, the Company is also committed to ensuring that the technology and environmental benefits the clean energy transition will bring are felt by all. These principles are articulated in the Company's mission, the Responsible Business Charter,[5] and the Company's Equity and Environmental Justice Policy and Stakeholder Engagement Framework.

Equity means engaging all stakeholders – including our customers and communities with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts and justice disparities. We define equity using three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Framework. These include:

[5] https://www.nationalgrid.com/document/134426/download

- **Procedural equity,** which focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation.
- **Distributional equity,** which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition.
- **Structural equity,** which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.

For example, customers today who are deemed income-eligible to participate in energy assistance or targeted energy efficiency programs are challenged by a lack of available and accessible information, hurdles to enrollment, and inequitable distribution of available assistance, which impact both procedural and distributional equity. Some of these challenges can be addressed through changes to tariffs and regulation while others will require legislative policy changes. The Company is taking steps today to understand and advance necessary changes to make these programs more equitable and effective, including in near-term filings at the Department and working with impacted stakeholders to inform these efforts.

As the Company continues to develop future programs that ensure all customers are equitably served, it is committed to integrating this focus across the business by:

- Increasing transparency and education about future infrastructure investment plans, including the need for investments and the benefits and impacts to a host community;
- Engaging early with stakeholders, including directly and via trusted community sources, and enhancing open communication that supports clear and timely information sharing, community feedback, and ongoing dialogue;
- Expanding the Company's understanding of community concerns and priorities;
- Enhancing project and program outcomes by identifying opportunities to mitigate adverse impacts and support community and customer benefits;
- Reducing barriers to participation in customer programs that can benefit low-income customers and environmental justice populations;
- Partnering with our communities and local organizations in support of broader social, economic, and environmental progress;
- Directly supporting economic opportunity and advancement, including through the development of a local, diverse clean energy workforce and supply chain; and
- Monitoring and informing on our progress in supporting equity and environmental justice on a regular and transparent basis.

Additionally, the Company is committed to working in partnership to identify and align around community benefits associated with clean energy infrastructure projects and exploring innovative ways to create agency. Massachusetts has precedent for this through vehicles such as The Community Preservation Act, which provides local communities the opportunity to collect and direct funding to community priorities, including open space protection and affordable housing. The Company looks forward to working with the GMAC's Equity Working Group to better identify and define opportunities to address policy, technology, infrastructure and program inequities as this Plan evolves and is implemented over time.

9.6.1 Aggregation of All Clean Technology Incentives (in Respective Scenarios) Focused on EJ Communities

The Company recognizes that people in EJCs, including low- and moderate- income (LMI) customers, face barriers to participation in programs designed to help customers manage their bills or participate in the clean energy transition. In April 2022, the Company realigned its customer organization to address the complexity of various customer segments, including LMI customers, with a vision and plan to create an organization focused on the performance of customer segments by having a deep, holistic understanding of LMI customers.

A comprehensive assessment was conducted with the following goals:

- Gain a deep understanding of the LMI customer segment
- Identify gaps within product offerings
- Apply key outcomes of an extensive ethnography study conducted in partnership with E-Source, and
- Coalesce work in-progress impacting LMI customers from across the Company

This effort identified gaps within the digital product space presenting barriers to the engagement of customers and program uptake, the need for more targeted and consistent outreach and marketing, and opportunities to better utilize and align existing data, efforts, and programs. The Company is addressing these gaps and opportunities through a holistic strategy that focuses on:

- Establishing and expanding partnerships, both internal and external
- Centralizing marketing to better align communications and outreach about products, programs, and services, and targeting these efforts
- Identifying ways to best structure products and solutions
- Expanding education and outreach, including the work of the Company's Customer Advocate team and in-person Customer Energy Savings events, which are jointly hosted with local governments, community organizations and other trusted partners.

The Company will continue to incorporate additional outreach and support to EJCs in its clean energy program design. This includes engaging with these communities to continue to evolve strategy, programs, and offerings for existing EE and EV programs to better meet the needs of EJC and LMI customers.

9.6.2 Discussion of Potential to Use Incentives and Dis-incentives to Align with Distribution Upgrades

Electricity rate designs, including as enabled by the Company's investment in AMI, are an important component of the Company's strategy for meeting the Commonwealth's energy goals efficiently. Innovative rates can provide customers with incentives and choices that support smart use of the grid, incentivize electrification, and reduce the overall costs of the energy transition.

The Company designs rates that reflect the costs and usage characteristics of each rate class, and considers precedents and procedures established by the Department of Public Utilities. In designing rates, the Company applies core rate design principles while incorporating public policy directives.

The average long-run per kWh electricity cost to customers can be expected to be mitigated to some extent due to the increased sales volumes that will come with electrification. However, given that the infrastructure investment necessary to enable increased sales volumes associated with electrification will necessarily come before increased sales, making thoughtful decisions around rate design and cost allocation will be critical to ensuring a just transition so that certain customers or classes of customers are not unduly burdened by higher system costs.

Distribution rates refer to the prices charged by electric distribution companies (EDCs) for delivering electricity to end-use consumers through their distribution networks. These rates recover the costs associated with investing in distribution infrastructure and maintaining and operating the distribution system, including power lines, transformers, substations, and other equipment necessary to ensure reliable delivery of electricity. Additionally, rates for distribution service include the costs of providing customer, administrative and related services for which the EDC is responsible.

Distribution rates include some or all of the following three key design components:

1. Fixed Charges: These rates are a flat fee charged to customers regardless of their electricity usage. Fixed charges as implemented to date typically cover the EDC's fixed customer costs, such as customer service, meter and meter reading and administrative expenses. This type of charge reflects costs that do not scale with load.
2. Demand Charges: Demand charges are calculated on the amount of capacity used by a customer during a specific time period, usually measured in kilowatts (kW). These charges reflect the cost of providing capacity to meet the highest demand levels and help incentivize customers to manage their peak electricity usage efficiently.
3. Volumetric Charges: Volumetric charges are calculated on the amount of electricity consumed by customers and are measured in kilowatt-hours (kWh). A volumetric rate design is typically associated with the cost of supplied energy.

The revenue requirement ultimately recovered by the Company must be approved by the Department of Public Utilities along with the rates designed to collect the Company's approved cost of service. The cost of service or revenue requirement represents the revenue required to pay all operating and capital costs, including a return on investment, depreciation expense, and income and property tax expense.

Rate Design

As discussed in this Future Grid Plan, the electric power system is at an important transitional stage where customer usage, the growth of distributed energy resources, environmental goals, and economic concerns are converging to create a complex environment for public policy, the EDC, and the customer. Within this context, rates can serve to help achieve a common goal (for example, innovative rate design has demonstrated potential to reduce customer peak demand, as demonstrated by numerous pilots including National Grid's 2015-2016 pilot in Worcester). However, rate design is only one tool in a strategy that includes distributed resources, energy efficiency, and efficient investment in the distribution system.

Electrification of homes and businesses and the increased demand for electric vehicles means that more electric energy will be required than ever before. The Company is taking steps to invest in its distribution system to accommodate this load and the renewable resources that will be introduced in support of the system. Continued load growth and investment must be managed, however, to ensure that customers do not face an exponential increase in the cost to serve them. In reviewing and approving rates, the Department has long adhered to commonly accepted ratemaking principles[1]. These are 1) efficiency, 2) simplicity, 3) continuity, 4) fairness, and 5) revenue stability. These five principles remain sound and should continue to be relied on in the evaluation of future rate proposals.

1. Efficiency means that the rate structure provides an accurate reflection of costs to inform consumers' decisions about how to best fulfill their energy needs. This means that the rate should allow for the collection of the Company's revenue requirement. A strict interpretation would mean that rates should not be discounted or reflect anything more or less than the cost to serve. A rate that reflects the actual embedded cost to serve informs the customer of the cost incurred by the EDC to serve them. A lower rate would send an improper price signal and potentially guide the customer into exerting a greater demand on the system than what is reflected in rates. A higher rate would potentially have the reverse effect and also send an improper price signal. In a future where electric demand is expected to grow significantly, it becomes ever more important to convey the actual cost of the system to the customer.
2. From the EDC perspective, traditional time-invariant volumetric rates are not an efficient means of recovering the costs of electric distribution infrastructure. The primary function of the EDC is to operate and maintain system infrastructure. This infrastructure is predicated on the capacity required by its customers and independent of the volume of electricity that flows through the electric grid. Volumetric charges are inefficient because the electric grid needs to meet the highest demand at any point in time and not the aggregate volume over a specified duration. Given the increasing electricity demand among customers due to various installations ranging from modern appliances to electric vehicles, the Company believes that demand charges, time varying rates (TVR), and fixed charges should be given greater consideration in the evaluation of future rate proposals.
3. Simplicity means that the rate structure should be easily understood; thereby enabling consumers to make appropriate decisions about use. The simplest electric rate design today is a two-part rate consisting of a customer charge and an energy charge. This is the type of design that residential customers and small business customers see today. Customers can easily understand a fixed charge and that volume of consumption can increase or decrease their bill. Simplicity, however, has become a challenging concept today when there is a demand for increasing amounts of data. The deployment of AMI meters enables for more data to be made available to customers in addition to more complex rate designs such as time-of-use variants. However, the Company believes that complex rate designs should be considered carefully. Information can be misunderstood if customers are not educated about the subject or do not have the time and resources to analyze complex data sets. It is important to understand that customers are diverse. For example, the development of the competitive energy supply market offers instructive lessons. The introduction of retail energy suppliers has given customers options and larger customers, in particular, can negotiate contracts and obtain optimal pricing for their needs. Such customers, however, may have staff devoted to analysis of energy costs and needs, whereas individual residential customers may have relatively less time or information to navigate complex pricing arrangements.
4. Continuity means that rate changes should be made in a predictable and gradual manner that allows customers reasonable time to adjust their consumption patterns in response to a change in structure. The continuity principle means that radical changes cannot be introduced at one time because it inevitably results in adverse bill impacts to one customer or another. Changing time-of-use periods is an example of a potential change that could significantly impact customers. Some may immediately gain advantage while others may see the opposite. For instance, changing a peak period from 9 am to 6 pm to 4 pm to 9 pm could have a material impact on certain customers. A small business that closes shop at 4 pm would benefit significantly without any change in behavior. Meanwhile, a restaurant could see a negative impact because the change would fall within its prime dinner service. Often times, new rate designs are introduced as options to smooth customer transitions. Optional rates mean that customers will self-select which can assist in the formation of a rate class.

Optional rates, however, also mean that the rate design may not change behavior because customers that do not see an immediate advantage are unlikely to elect the rate.

5. Fairness means that no class of consumers should pay more than the costs of serving that rate class. This principle seeks to limit the amount of cross-subsidization across rate classes or customers within a rate class. Additionally, rate design choices can have meaningful impacts on public policy goals and customer adoption of clean energy technologies.
6. As clean energy markets mature and adoption rates grow significantly in furtherance of state goals, rate designs that are mindful of the continued need for EDCs to equitably recover their fixed costs from customers will be increasingly critical. This may mean future transitions away from purely volumetric rates to more sophisticated rate structures that preserve contributions from all customers that take service from an EDC. Customer charges and demand-related charges are potential mechanisms for achieving this outcome. Transitioning cost recovery away from high volumetric charges could have an added benefit of improving the economics of electrification where volumetric usage may be higher. Any change to rate designs requires thoughtful consideration, particularly related to impacts on low-income customers that may be disproportionally impacted by fixed charges or who may have limited opportunities to avoid demand charges. Given this, any rate reform should holistically consider how the Commonwealth's existing low-income discounts mitigate these unintended impacts.
7. Revenue stability means that the amount of revenue an EDC recovers through its rates should not vary significantly over a period of one or two years. Revenue stability leads to stable rates. If rates are unable to collect the costs incurred by the Company, more frequent rate changes would be required. In recent years, some parties have argued for pricing based purely on marginal cost. The arguments supporting this are often confused because they do not reconcile marginal costs with embedded costs. Marginal costs represent the cost of making a future investment while embedded costs represent the costs that have already been incurred. The former represents a price signal to customers about the implications of their future load while the latter represents the actual cost to serve. Rates are a blend of both. They need to send appropriate price signals yet recover the total cost to serve. Pricing purely on marginal cost would ignore existing costs and leave the Company under-recovered and ultimately result in increased rates for all other customers. To manage costs to all customers, the total cost of the distribution system needs to be shared among its users.

The long-standing rate principles of efficiency, simplicity, continuity, fairness, and revenue stability need to be weighed against each other and cannot be viewed in isolation. Often times, one principle may be prioritized over another in order to achieve an outcome that meets the real world needs of customers, policymakers, and the EDCs. The Company recommends that strong emphasis should be given to efficiency and cost responsibility in the years ahead. Maintaining cost responsibility will help reinforce fairness and stability and allow for continued investment in the electric power system in order to meet future system demands. In this fashion, there can be continued investment in the distribution system without a significant impact on customers over the long run.

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

The Company recognizes that populations in EJ and other communities may face barriers to participation in programs that help customers manage bills or provide new opportunities for customer participation in the clean energy transition. The Company will continue to offer additional outreach and support to low- to moderate-income ("LMI") customers in its clean energy program designs and in its community and customer outreach and engagement, as it has done in its EE and EV programs to date.

National Grid is committed to supporting low-income customers and proactively delivering programs to protect the most vulnerable customers. The Company currently offers several programs that support low-income customers, including the Rate R-2 discount. The existing R-2 rate provides a 32% discount on a customer's entire electricity bill and is available to residential customers at or below 60% state median income. While the current discount rate improves affordability for low-income customers, a multi-tiered discount rate would be more equitable. In its recent rate case, the Company proposed a multi-tiered discount rate with higher bill discounts for lower income customers. The goal is to keep low-income customers who have average electricity consumption to below a 3.4% electric energy burden target. Electric energy burden is defined as the percentage of gross household income spent on electricity costs. The Company's proposal also includes an outreach and education plan to increase low-income program enrollment. Together, these proposals will help improve affordability for the Commonwealth's low-income customers. The Company's full proposal can be found in its rate case filed on November 16, 2023 (D.P.U. 23-150).

The Company does not maintain records of customer income, nor would that be appropriate. Enrollment in a discounted rate today is based on verification with the Commonwealth that a customer is enrolled in a means-tested program. Thus, the Commonwealth needs to partner with the Company in the implementation of such a program. As the Commonwealth advances towards electrification and the Company increases its infrastructure investment to meet policy goals, the opportunity to address the impacts to LMI customers is immediate.

The need for investment to achieve state climate goals also warrants discussion on how incentives that are paid to customers are recovered through rates, e.g., EE charges or, whether incentives should be managed through distribution charges. As the Company moves to an increasingly electrified system, careful consideration should be given to cost allocation and rate design principles to ensure a just transition. Moreover, it is important to note that the layering of incentives into utility rates will ultimately increase costs. Consequently, it will be important to design rates that will minimize cost shifting and not increase the cost burden for customers.

On December 6, 2023, the Department of Public Utilities issued its D.P.U. 20-80-B Order on Regulatory Principles and Framework. This Order addressed the Department's investigation into the role of gas local distribution companies in the achievement of the Commonwealth's 2050 climate goals (aka "Future of Gas"). In that Order, the Department acknowledged the potential for a growing cost burden on customers as the Commonwealth advanced its policy of electrification. Consequently, the Department plans to address these issues in a separate proceeding that will be "dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions" (Order at 16).

On January 4, 2024, the Department opened this separate proceeding as an inquiry to examine energy burden with a focus on energy affordability for residential customers of the EDCs (and of gas distribution companies) (D.P.U. 24-15). The Company welcomes this investigation and looks forward to a robust discussion with the Department, EDCs, and stakeholders.

A myriad of related issues emerges as the Commonwealth, EDCs, and stakeholders contemplate issues of equity and rate design, each of which should be comprehensively addressed by the Department and interested stakeholders in a longer-term process than the ESMP process allows, including:

- TVR should be considered in the context of a comprehensive policy in consideration of solar and storage. Efforts at altering customer behavior should not be viewed in isolation as the impact to the electric power system is the result of the sum total of customer actions.
- Pursuant to Chapter 179 of the Acts of 2022, An Act Driving Clean Energy and Offshore Wind, the Company filed an electric vehicle specific time varying rate in D.P.U. 23-85.

Targeted TVR rate design is a granular approach that will offer bill savings to selected participants.

- The Company has been actively participating in an AMI stakeholder process ordered under D.P.U. 21-81-B.The Order directed the stakeholder process to focus on 1) customer and third-party access to customer usage data; 2) customer education and engagement; 3) billing of TVR offered by competitive suppliers; and 4) AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products. Issues of supplier TVR rates have an impact on any future TVR basic service proposal. Municipal aggregations and competitive suppliers have taken a significant hold in the Company's territory. As of December 2023, 45% of customers in the Company's service territory remain on Basic Service.
- Customer Education is a pivotal component of AMI deployment and rate design. AMI will allow for the collection of more granular data among residential customers in a cost-effective fashion. Today, the Company cannot collect that type of hourly or 15-minute or less intervals without deployment of costly interval meters. Collection of data will allow the Company and policymakers to better understand how customers behave across municipalities. Analysis of that information will lead to rate designs that can address different usage patterns as well as the ability to segment customers more granularly over time.
- Complex rate designs require greater communication with the customer to educate them on how their energy profile impacts their bill and how they can manage their costs through the tools available to them. The complexity of any rate design needs to be balanced against a customer's ability to act on price signals in an effective and efficient manner.
- The Company supports transitioning to an electrified future in an equitable and just manner and supports rate designs and public policy programs that will result in a constructive path forward.

9.6.4 Potential Incentive Allocation Movement Among Clean Technologies Ultimately Flowing to EJ Communities

The Company recognizes that people in EJCs face barriers to participation in programs designed to help customers manage their bills or participate in the clean energy transition. Per Section 9.6.1, the Company has a holistic strategy to identify, engage, and provide clean energy products and solutions to EJCs, including through ongoing EE and EV program efforts. The Company will continue to incorporate additional outreach and support to EJCs in its clean energy program design and in its community and customer outreach and engagement, working with affected and representative stakeholders, including the GMAC Equity Working Group.

The Company has also identified several programs in this Future Grid Plan that are that are either in flight and/or will be submitted to the Department for consideration, including the Resilient Neighborhoods program discussed in Section 6.11.3, which is designed to improve climate adaptation and resiliency for communities via the deployment of solar located on Company property. The Company is currently working with potential community hosts to identify benefits that can be leveraged from solar, including creating resiliency hubs and EV charging support, thereby aligning and leveraging program funding and incentives being used for one technology to support other efforts.

9.7 New Technology Platforms

The Company proposes to build on its currently in place and in-progress technology platforms, including those approved in the first and second ESMP periods, with further investments to support delivery of the 2035- 2050 ESMP objectives.

Consistent with the framework in Section 4 and Section 6, the following technology investments categories are described:

1. **Network management and communications** includes technologies that the Company uses to communicate with, monitor, and control assets on the network and to manage and respond to grid outages and abnormal system conditions.
2. **Metering and billing systems** include technologies that the Company uses to measure customer energy usage on the grid and issue accurate bills based on those meter reads.
3. **Customer portals** include the customer-facing and internal systems that the Company uses to leverage today to manage customer programs such as those related to EE, EVs, and new customer interconnections.
4. **Data** includes the type of data that the network planning and operations and customers have access to, as well as the Company's ability to manage, integrate, and operationalize that data to transform how the Company operates and plans the grid.
5. **Asset planning, management, and work execution** includes the systems that the Company uses to support grid planning and design, construction and capital deployment, and regular system maintenance and field operations.
6. **Security** includes measures in place to ensure the security of the Company's technology systems from potential cyber threats and attacks.

The Company expects to focus on the six key areas identified above in the 2035-2050 period to advance the digital transformation of the Company.

Network management and communications

A foundation of the Company's modernization plan is the development of a granular and real-time model or "digital twin" of the Company's electric transmission and distribution network. This model also features real-time control of network assets, including predictive and automated schemes to reconfigure the system for various purposes, including customer reliability, efficiency, and the prioritization of clean energy use. The end-state of this transformation will be characterized by shorter and less frequent outages, higher quality power, and the integration of clean energy. To avoid outages in the future, this self-healing system will be able to isolate portions of the grid and leverage a variety of sources of energy (such as DERS) to create microgrids within the larger electric grid based on real-time conditions.

To enable this future state, the deployment of sensors, controls, and real-time communications throughout the network will need to be enhanced to make the bidirectional data collection and control from the field to the operating center and back again instantaneous, with data transmission, interpretation, strategy, and control schemes deployed at the sub-second timeframe.

To enable the collection, interpretation, and transmission of data across the network, the Company will enhance the capabilities of the localized Field Area Networks (FAN) and Wide Area Networks (WAN) that facilitate data management on the massive scale required for the incorporation of data from the grid edge like smart meters and grid-supporting DER. Dozens of systems, monitoring, controlling, and coordinating thousands assets will need to be conducted faster, more reliably, and with minimal human intervention.

Metering and billing systems

The future of metering and billing systems are tightly coupled with the broader trends of digitization, consumer empowerment, and the integration of renewable energy and DERs. As the grid continues to evolve, these systems will reflect these changes, offering more granularity, transparency, and adaptability to operators and customers alike. In the future, the advanced customer meter will be the gateway for customer empowerment as an active participant in the energy system.

With the deployment of AMI – embodied by the new generation of smart meters – the utility activates the ability to facilitate two-way communication between the meter, operating center, and end-customer. This not only allows for real-time consumption tracking, but also a variety of other OT use cases such as remote connect/disconnect to significantly improve the move-in/move-out process for customers and the better integration of DERs. Advanced features and programs will enable customers' DERs to participate in the energy marketplace in a way not possible with today's meters (e.g., transactive energy programs where customers can change the energy services that they're paid to provide through their DER in real-time.) A good example would be the Company sending an optional incentive offering to a customer's phone to provide voltage support in a targeted location on the grid in real-time.

These AMI meters also function as grid edge sensors for the purpose of network management and will offer the utility valuable insight about conditions at the grid edge in real-time. This enables a whole new set of use-cases, including last-gasp and advanced outage management functionality. This functionality would allow the utility to identify which AMI meters are no longer connected to the utility network, thereby creating a model of where a distribution network fault may have occurred so the Outage Management System (OMS) can reconfigure the network to minimize or prevent outages for customers via microgrid enablement and dispatch crews to the fault location to restore power to customers impacted by the outage.

An enhanced billing and payment process will also provide considerable experience improvements for customers to receive, review, and pay their energy bills or credits in an environment that meets evolving customer needs and expectations. The most common interaction that customers have with their utility is around their monthly bill, and with the introduction of variable rates and transactive energy markets, the number of customer questions associated with these changes will increase significantly. The Company's new billing and payment portal will offer customers targeted information that will reduce the need for them to call in to speak to a Customer Service Representative by providing detailed information about Company rates, as well as access to a suite of actions that they can take to dig deeper into their consumption data details or take action to reduce their costs in the future.

Customer portals

The Company will continue to enable a variety of new, automated processes with enhanced customer experiences as data is processed and communicated more quickly via customer portals. These portals will empower the customer to make more active decisions around their energy and enact those changes in real-time. As the Company offers more opportunities for customers to control their energy costs, consumption, self-production, and other choices, the Company will aim to offer an intuitive user experience with seamless designs, easy-to-navigate interfaces, and customization features that will make it easy for customers to complete the required tasks.

Customers will not only need an easy, efficient, and engaging way to review that data, but will also expect the Company to make recommendations and digital products to make it easy for them to take further action on their energy goals. The deployment of AMI will enable customers to access exponentially more data about their account, including their energy consumption and load profile. The future billing portal will provide a customer-centric web platform that will enable customers to review this data, receive recommendations on how they can achieve their energy goals, view economic models of the impact of those measures, and securely provide that data to third party vendors that can make customer actions even easier.

Enhanced customer portals will also significantly improve the experience of customers who choose to pursue and monetize DER. In the early phases of their DER journey, customers will be able to efficiently access and review their energy consumption data and understand if solar, energy storage, or other DER-actions are best for them. They can then seamlessly and securely provide data that is critical for project design and development to third party vendors. Vendors will be provided a package of data on the customer, their energy consumption, location on the grid, and expected process for interconnection to significantly reduce the time and soft cost associated with project development.

Data

Real-time data collection, data transmission, and analytical processes will enable the Company to make informed strategic and operational choices, analyzing vast amounts of data from equipment, sensors, and customer behavior. This will enable the Company to make accurate predictions and optimize resource allocation. In short, the Company will leverage real-time data and analytics to do more with less.

The Company will leverage machine learning and advanced analytics to transform a variety of processes and capabilities, (e.g., predictive maintenance, load forecasting, customer service, security, DER integration). The Company currently collects and has access to more data than can be reliably processed with today's technology. However, evolving technologies will create new use cases – making the process of leveraging this data faster, more reliable, and cost effective.

As machine learning capabilities evolve, the Company will continue to train models to be able to analyze performance anomalies and operational characteristics of assets to mitigate asset failures before they occur. For example, modeling and extrapolation of vibration sensor data at a substation could simulate when an equipment failure might occur so asset management teams can prioritize the exact time to send a maintenance crew.

The Company will also leverage advanced data analytics and modeling to create new rate structures and incentives that not only solve today's load management challenges, but also prevent future issues based on inputs from the Company's systems and third-party data. This could include analyzing EV sales, real estate, or permitting data to project load impacts on the grid and take mitigating action prior to significant load changes that could require costly infrastructure upgrades.

The future data system will ensure the Company has accurate, timely data that can be used for short and long-term analysis of network operations and health, energy supply and demand, weather and climate impacts, and customer preferences. This analysis will enable the Company to address issues quickly, conduct predictive maintenance, extend the lifespan of critical components, integrate more renewables, tailor products to Company customer needs, and operate the grid more efficiently and effectively.

Robust data security and encryption will be essential to protect customer and network data, comply with regulatory requirements, and allow for third party sharing with suitable protections in place. Data will be the backbone of the Company's digital transformation and will help pave the way to a more sustainable and resilient energy system.

Asset planning, management, and work execution

A key focus of the Company's strategy to minimize the frequency and duration of outages while keeping costs low is the optimization of asset management and work execution. As climate change poses new risks and challenges to maintaining the distribution network and assets, digital products and data will be increasingly relied upon to understand and predict asset conditions.

Asset management teams are deploying advanced sensors – embedded in field equipment like transformers – to provide real-time data on performance and conditions (such as heat) to facilitate early detection of problems and optimizing usage of the asset. As noted above, the Company's asset management teams can then leverage machine learning to predict when assets are likely to fail or need maintenance. This proactive approach minimizes downtime, reduces costs, and extends asset lifespans.

When visual inspections need to be conducted, the Company and affiliated vendors will increasingly rely on drone or robot-assisted inspection techniques to collect detailed visual asset data, reduce costs, and enhance safety at the inspection site. Unmanned Aerial System (UAS) and other remote-controlled systems can access challenging and hazardous locations (such as above high-voltage transmission lines and close to dangerous or damaged equipment) where it can collect high quality data such as photogrammetry, infrared imagery, and LiDAR to inspect both utility assets and the environmental risks that surround them.

Integrating this asset data, analytics, and machine learning with an enhanced work management tool will enable the Company to balance priorities of reliability, sustainability, and affordability during periods of notable change in the industry and the Commonwealth. Pairing enhanced asset and workforce management solutions, the Company's teams will enhance the grid's resilience, reliability, and affordability.

Security

Robust cybersecurity measures ensure the Company safeguards critical infrastructure, protects customer data, and ensures uninterrupted operations in the face of evolving cyber threats. Internet of Things (IoT) devices in smart grid applications and an increased use of digital systems, data communication, and smart grid technologies presents new entry points for cyber attackers. Data from these devices will be critical for optimizing grid performance and making informed decisions.

The Company will employ continuous monitoring and threat detection mechanisms, intrusion detection systems and security analytics, and comprehensive incident response and recovery plans. Machine learning algorithms can detect unusual patterns of behavior and trigger appropriate responses to mitigate cybersecurity risks. It will be critical that the Company communicates and engages with other utility and industry partners to collaborate and share information about cybersecurity threats and best practices. Building a collective knowledge base will enable the industry to proactively address emerging threats and develop more effective cybersecurity strategies. In 2035 – 2050, cybersecurity will require significant investment across all digital and business initiatives to ensure a safe, secure, and reliable network remains in place for all customers.

Section 10
Reliable and Resilient Distribution System

This section articulates the importance of reliability and resiliency and describes the Company's programs and investments to ensure its system is prepared for future climate hazards.

Key Take-Aways

- The Company has a strong track record of building and maintaining a resilient system that has adapted to meet the evolving challenges and threats. The pursuit of the Commonwealth's clean energy and climate goals and associated increased electrification result in customers having an increased dependency on the resiliency and reliability for their livelihood.
- Residents of the Commonwealth have already begun to experience the effects of climate change. The Company is constantly monitoring and adapting to climate-related threats posed to the electrical network. Identified pertinent threats include coastal flooding, temperature extremes (both high and low), extreme winds, and wildfire. Resiliency measures (largely driven by engineering tactics and construction design standards) are in place to combat these threats.
- Reliability and resiliency investments are considered critical to the continued safe and reliable operation of the network. As such, the Company is not proposing any direct reliability or resiliency investments in the Future Grid Plan incremental to its base (core) investments. However, there are investments within the Plan driven by network capacity deficiencies that have the secondary benefit of improved reliability and resiliency, which are discussed in this Section.

10.0 Reliable and Resilient Distribution System

The Company undertakes careful planning to ensure reliable and resilient network performance. This is becoming ever more important in an increasingly electrified world. The Company is not proposing any resiliency investments incremental to its base spending (core) resiliency investments in the Future Grid Plan and the information in this Section provides a holistic view of the Company's resiliency activities. The investments which comprise the Future Grid Plan are proposed to address the capacity challenges presented by electrification-driven load growth; however, these investments may have the secondary benefit of improving the reliability and resiliency of the distribution system. For example, all assets installed through these Future Grid Plan investments will be designed to meet the current Distribution Construction Standards, and the incremental capacity enabled through the investments proposed in Section 6 will provide additional flexibility to respond to the emerging resiliency challenges described in this Section.

This Section will:

- Provide an overview of the Commonwealth's *Climate Change Assessment*[1] and *Hazard Mitigation and Climate Adaptation Plan*[2]
- Define and highlight the need for grid resiliency
- Review many of the Company's distribution reliability and resiliency programs and how these are expected to adapt and evolve within a continuously changing climate
- Assess the grid's vulnerability with respect to expected climate hazards

10.1 Review of the Commonwealth's Climate Change Assessment and Hazard Mitigation and Climate Adaptation Plans

The Massachusetts Integrated State Hazard Mitigation and Climate Adaptation Plan (SHMCAP), published in 2018 and 2023, is a first-of-its kind statewide plan that fully integrates a traditional hazard mitigation plan with a climate change adaptation plan. The SHMCAP accounts for projected changes in precipitation, temperature, sea level rise, and extreme weather events to position the Commonwealth to reduce risks associated with climate change. The Company and its assets fall under the "Built Environment" or "Infrastructure" categories of the SHMCAP.

An Act Driving Clean Energy and Offshore Wind at Section 92B (b)(i) specifies that each ESMP include and describe in detail improvements to the electric distribution system to increase reliability and strengthen system resiliency so potential weather-related and disaster-related risks are addressed. The transition to Net Zero by 2050 and the full electrification of the Commonwealth will bring new expectations for a reliable and resilient network as customers rely on the Company's networks for increased electric vehicle charging and heating in addition to the many ways that they use electricity today.

Weather events, primarily storms involving wind and/or precipitation, can result in vegetation and distribution asset failures and have significant impact on the distribution system's performance. Climate change is widely understood to be contributing to an increase in frequency and severity of storm events. Additionally, increased customer reliance on electricity has led to increased expectations for the distribution system's reliable performance. Significant outage durations, even when resulting from significant weather events, are becoming untenable to many customers.

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[1] Massachusetts Climate Change Assessment | Mass.gov
[2] 2023 ResilientMass Plan | Mass.gov

As the Company further develops its climate vulnerability assessment, it will incorporate findings and align with these plans.

10.2 Distribution Reliability Programs

Prior to discussing the Company's detailed plans below, there must first be alignment on the definitions of Resilience and Reliability:

Reliability has traditionally focused on upholding performance according to regulatory reporting criteria. This excludes the impacts from major events which cause outages that are statistically outside the norm for the system. This includes:

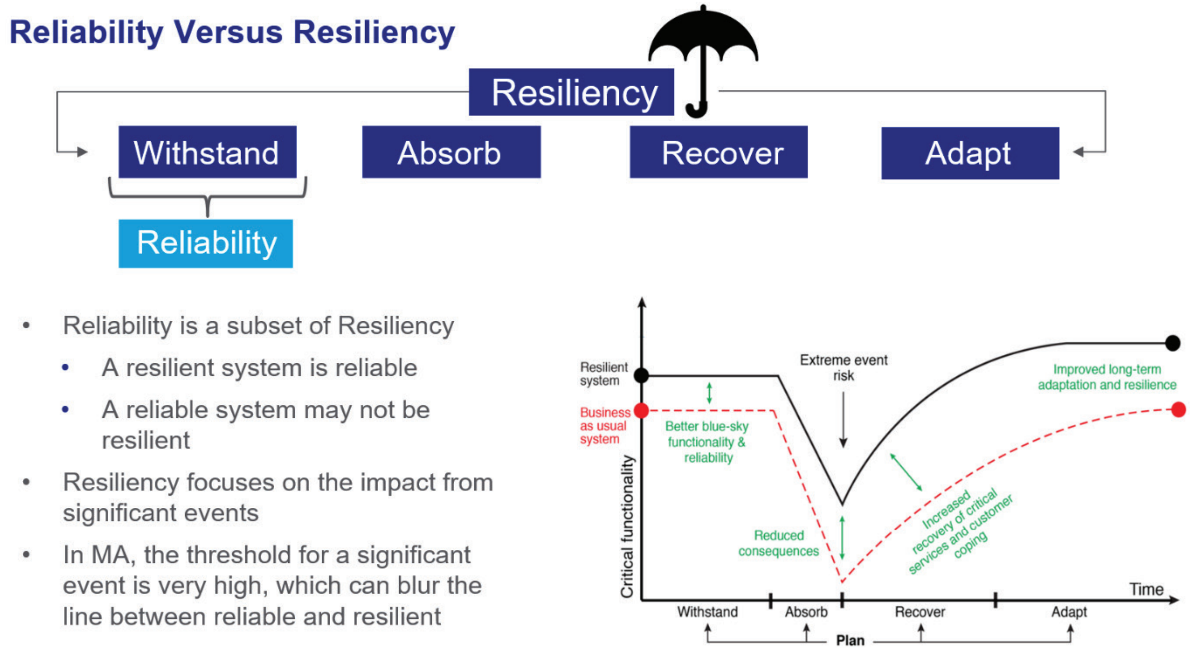
- Service Quality Guidelines D.P.U. 12-120-D Attachment A, Section I-B Definitions:
  - "Excludable Major Event" means a major Interruption event that meets one of the three following criteria:
    - (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act);
    - (2) any other event that causes an unplanned Interruption of service to fifteen percent or more of the Electric Company's total customers in the Electric Company's entire service territory; or
    - (3) the event was a result of the failure of another Company's transmission or power supply system.
  - Excludable Major Events apply to all SQ reliability metrics. Notwithstanding the foregoing criteria, an Interruption event caused by extreme temperature condition is not an Excludable Major Event.

- Eversource Rate Case - D.P.U. 22-22 – Section XIII. - SERVICE QUALITY PERFORMANCE EXEMPTION[3]
  - Temporary approval of using Eversource's method of "... *event days where the SAIDI values exceed the mean plus four standard deviations.*" (2023 thresholds - MECo: 25.214 minutes, NANCo: 161.438 minutes)

Resiliency can broadly be defined as the ability of the distribution system to withstand and recover from disturbances, including major events. It is expected that the Company's service territory will be experiencing more common and more severe storm events. Although these are excluded from traditional reliability analyses, the Company will nevertheless consider the impacts of these events as part of its system resilience and reliability planning.

[3] Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan

Exhibit 10.1 – System Resiliency vs. Reliability



Many factors contribute to and have an impact on distribution system resiliency and reliability. For example, the system can be designed and constructed to withstand increasing risks (i.e., “hardening” the system), or certain emergency response and operational activities are employed during and immediately after an event that causes electric service disruption. At the Company, specific areas in which system resiliency/hardening are a focus include:

- Regular updates to construction and equipment standards applied to distribution infrastructure projects
- The Company’s vegetation management programs
- Asset Management practices and distribution system planning studies to identify existing and project future system performance concerns and the infrastructure development required to address the concerns identified
- The consideration of both reactive and proactive infrastructure development programs that adopt new and/or replace/modify existing assets
- The development, continued refinement, training, and execution of the Company’s Emergency Response Plan (ERP)
- Tracking the latest developments in climate science and the trajectory of climate change within the service territory

The Company has developed robust processes in each of these areas which give the Company the ability to respond both proactively and reactively as the impacts of climate change on distribution system performance are realized. The Company recognizes that the threat of climate change is significant, and it cannot be resolved through isolated or short-term initiatives. Accordingly, preparing for and responding to climate change is embedded in the way the Company plans, constructs, and operates its system as a normal course of business. Specific ongoing and completed resiliency and hardening measures are discussed within this Future Grid Plan as examples of ways that the

Company's response to climate challenges have materialized. As the understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of the Company's processes will allow additional measures to be developed and implemented.

10.2.1 Distribution Construction Standards

The Company regularly reviews and updates its Distribution Construction Standards. The prompts for reviews are wide ranging and include items such as assessing continued availability of specific equipment, requests from internal departments of the Company revisions to regulations that impact the Company's operations, and new technology adoption. Changes in construction standards stemming from environmental change are not new and the Company has implemented a significant number of improvements over the years that have now become standard practice.

Over the past several years, the Company's Distribution Construction Standards have been reviewed and modified with a specific focus on changes that will advance system storm hardening and resiliency. These changes are designed to improve distribution system performance during extreme weather events in several distinct ways including:

(i) Reducing the number of customers experiencing outages
(ii) Reducing the duration of outages when they are experienced by customers
(iii) Mitigating the impact to customers during distribution system outages

As a result of its review, the Company added a Storm Hardening section to its Distribution Construction Standards in 2014.

The Storm Hardening section is unique in that it describes and explains the Company's approach to improving the distribution system's resilience through storm hardening, with specific updates to the standards then embedded in other sections. The Storm Hardening Standards discussed in this section of the Distribution Construction Standards are one part of the Company's comprehensive approach to resiliency. They primarily focus on making distribution system components more resilient electrically and structurally. These changes are intended to be part of all routine construction going forward, not just for use in targeted storm hardening of feeders (i.e., distribution circuits). Near-term considerations for resilience focus on system operation and restoration after a major event. Long-term considerations focus on infrastructure improvements that must be done before a major event – including aspects of grid operation, vegetation management, electrical and structural strength, and robustness of distribution system components. Resilience considers all hazards and events, including high-impact low-probability events that are commonly excluded from reliability reporting.

During extreme weather events, most damage to the overhead distribution system is caused by falling limbs and trees. The approaches put into practice by the Distribution Construction Standards attempt to reduce electrical outages or structural damage caused by trees and limbs. In particular, the standards are aimed at limiting the number of customers affected by tree and limb related outages and limiting the duration of those outages by allowing partial restoration of feeders and allowing quicker restoration of damaged lines. Storm hardening standards will be applied to all new or replaced structures in critical locations, coastal areas, and locations at risk of cascading failures (e.g., chain-reaction of equipment failures). Storm hardening is implemented in the following areas:

- Critical structures hardening
- Cascading prevention
- Coastline area targeted hardening
- Existing lines hardening

The Company's review of construction standards prompted by the impacts of climate change will continue. The Company is participating in ongoing research work at the Electric Power Research Institute (EPRI) on distribution grid resiliency. This work has included research into the response of overhead distribution lines to impacts from falling trees and limbs. The preliminary results from the EPRI work have brought about changes to the Company's Distribution Construction Standards, with a focus on reducing the number of customers affected by major storms through selective strengthening of structures and conductors at critical locations like tie points between feeders, automated switching points, and the multiple circuit lines. Early study results have also driven changes to the Company's standards that are focused on the reduction of the duration of outages through the strengthening of manual switching structures, and the use of periodic dead-end structures to prevent cascading failures.

The Company continues to participate in ongoing work at EPRI focused on how individual components fail in a line hit by falling trees and limbs. The goal of this work is to find ways to make lines fail in ways that are more easily and quickly restored. For example, the study is evaluating the potential benefits of using sacrificial components at sensitive locations like dead end structures. As useful and practical results from this work become available, the Company will make further modifications and additions to its construction standards.

Exhibit 10.2 – Breakaway Connectors

In addition to continued consideration of developing technologies which can be applied to promote distribution resiliency, the Company is in the process of examining its Distribution Construction Standards through the ongoing climate vulnerability assessment work which is projecting the impacts of climate change to its system (Section 10.4).

10.2.2 Vegetation Management Programs

The Company's Cycle Pruning Program is designed to keep vegetation a safe distance from the power lines. When vegetation grows into power lines, it can cause service interruptions, pose a potential public safety hazard, and in some cases, start a fire. Maintaining clearance between vegetation and the power lines helps mitigate these risks and allows the Company to restore power more safely and efficiently during a weather event.

The Company has a dedicated Vegetation Strategy team which is responsible for developing long-term strategy, planning, budgeting, and delivering the annual work plan to ensure safe and reliable service for Company customers. The Company continues to adapt its Vegetation Management Program to address the latest research, meet regulatory and financial targets, and achieve high levels of customer reliability so that the Company's program reflects best practices and results in the creation of an industry best-in-class program. The Company is also deploying new digital products to support its vegetation strategy, such as the Scaled Agile Framework (SAFe) described in Section 6.3.1.

The impacts of climate change will create a significant challenge in meeting the program's goals for many years to come. With an estimated stocking density of 208 trees per mile, the Company's electric system across the Commonwealth is vulnerable to harsh conditions during major weather events, which are becoming both more common and more severe due to climate change. These events can cause substantial damage to the system and cause interruptions that can last for multiple days.

Exhibit 10.3 – Weather-Related Tree Contact

The impacts of climate change are already noticeable on the Company's system. The Company's assessment is that over time, a fixed cycle-based approach will no longer be sufficient to prevent vegetation from growing into the power lines. As illustrated in Exhibit 10.4 and Exhibit 10.5, a significant portion of the Commonwealth has changed from hardiness zone 5 in 1990, to zone 6 in 2015. This means that temperatures are rising, which will increase vegetation growth rates.

With higher average annual temperatures and longer growing seasons, an increase of vegetation growth into conductors will occur in between pruning cycles. This creates a public safety hazard, makes routine maintenance both more dangerous and more expensive, and increases restoration times during storms. To help address this climate change impact, the Company has transitioned to a condition-based planning approach to determine when and where pruning should occur on its entire distribution system.

Exhibit 10.4 – Difference Between 1990 and 2015 USDA Hardiness Zones

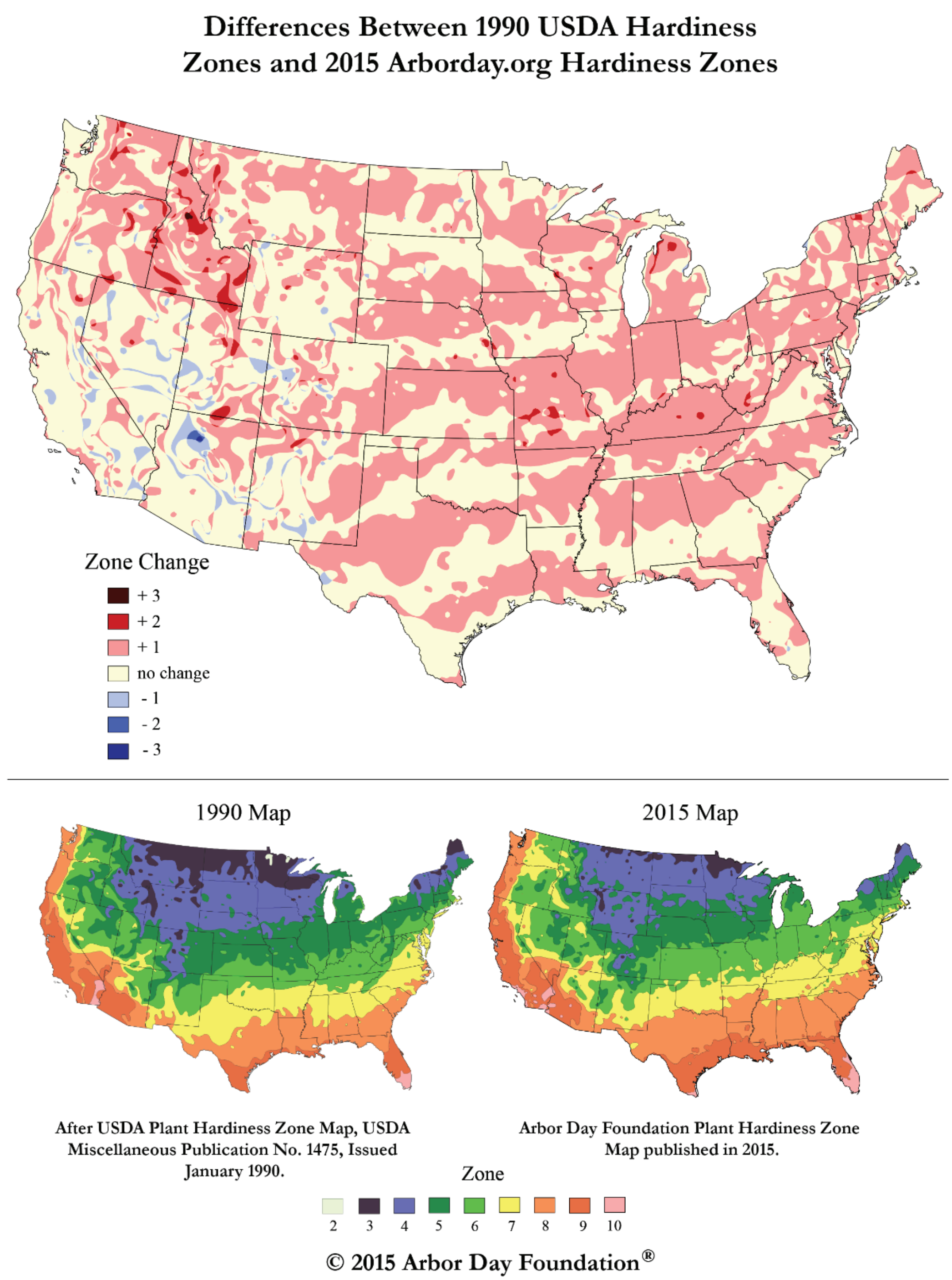
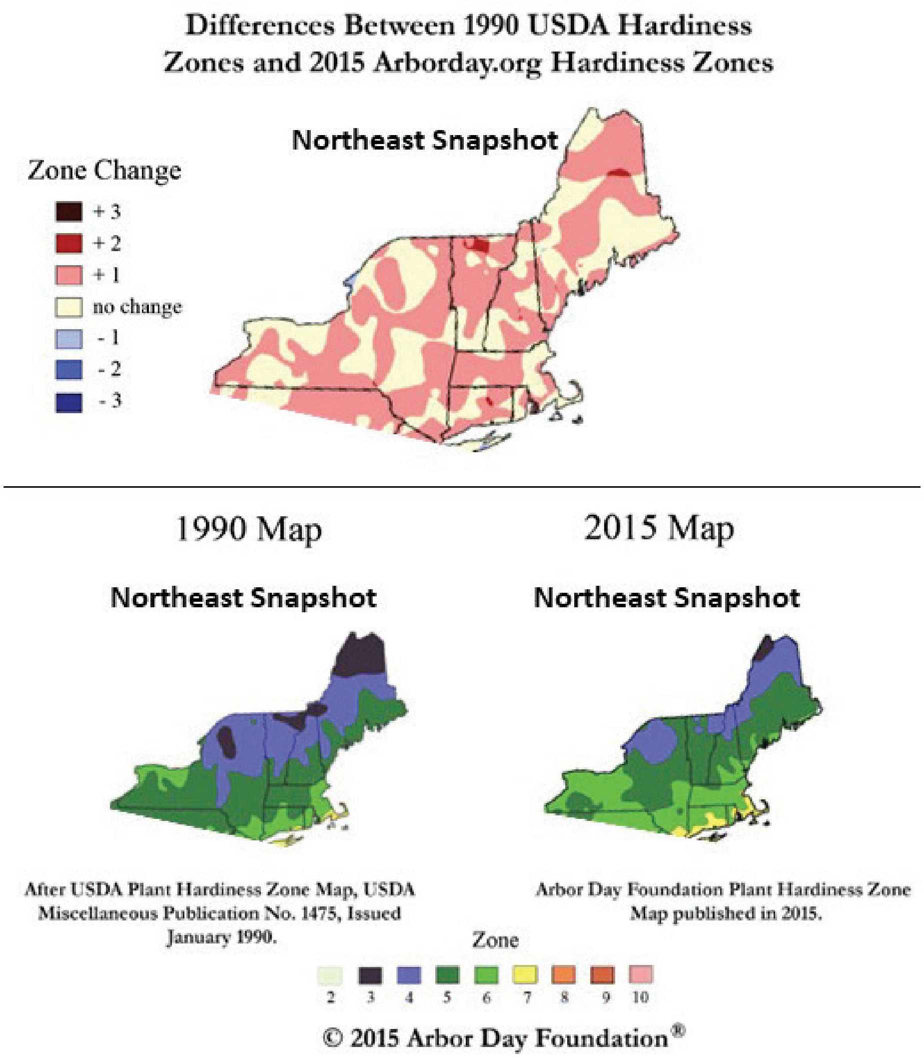


Exhibit 10.5 – Northeast Snapshot of Difference Between 1990 and 2015 USDA Hardiness Zones



In response to these trends, over the previous five years, the Company has spent approximately $142 million on maintenance pruning, Enhanced Hazard Tree Mitigation (EHTM), and Enhanced Vegetation Management (EVM) to protect its electric distribution system and ensure safe and reliable service for the Company's customers in the Commonwealth. As the Company continues to build more infrastructure to meet the needs of Company customers, it will be essential to increase the vegetation management budget proportionally to maintain that infrastructure in the future.

The Company's EHTM program seeks to identify and remove hazard trees, which are diseased or dying trees, which could potentially impact the electric system on both blue-sky days and during weather events. The EHTM program provides a significant reliability benefit to the Company's customers across the Commonwealth. Since its inception, the Company's EHTM program has averaged a 19% reduction in tree-related events, a 39% reduction in customers interrupted, and a 32% reduction in customer minutes interrupted on circuits to which it was applied the year following EHTM, compared to a three-year average prior to EHTM.

The Company's EHTM program is designed to be flexible to evolve to address constantly changing issues which affect vegetation throughout the Commonwealth, such as extreme drought and invasive species, both of which reduce tree strength and increase the risk of outages, resulting in large numbers of dead or dying trees which will impact the electric system during weather events.

In addition to these core programs, the Company also began implementing the EVM as a pilot program in Massachusetts in 2019. It targets worst-performing circuits which have experienced large numbers of tree-related outages and serves critical infrastructure. The pilot seeks to achieve greater clearance between vegetation and power lines. In some areas ground-to-sky clearing will be implemented, meaning there will be no vegetation growing over the wires. The pilot program also takes a similar approach as the EHTM program and removes large numbers of hazard trees. With these measures demonstrated, the Company's distribution system will be more resilient during major events. The EVM Pilot has averaged a 39% reduction in tree-related events, a 47% reduction in customers interrupted, and a 44% reduction in customer minutes interrupted after work was completed.

10.2.3 Asset Management Practices and Distribution System Planning

Asset management is the coordinated capability to make lifecycle cost, risk, and performance decisions and thereby create value for an organization and its customers from its assets. Engineering is the capability to design, build, and implement practical solutions to complex problems and requirements across multiple disciplines. At the Company, asset management and engineering are vital to delivering safe, efficient, reliable, and environmentally sound performance in each of its lines of business.

Embedded within the Company's asset management practices are the processes followed by distribution system planners in the execution of long-range distribution system planning studies. System performance assessments executed within these studies include a focus on system voltage, capacity, asset condition, and reliability. A completed analysis applies the Distribution Engineering Planning Criteria (which details acceptable performance) in the identification of existing and projected system performance concerns. A completed study includes recommendations for infrastructure development projects that will address all concerns identified.

The planning process and its performance assessments are fundamental and robust enough to identify trends in system performance degradation that might stem from the environmental impact of climate change and make recommendations that mitigate the impact of the root cause. An example provided in Section 10.2.1 is the Company's adoption of tree wire and spacer cable systems in its construction standards as a direct result of analysis done by distribution system planners. As the Company enhances its overall asset management capabilities and the subset of distribution system planning processes, it will result in continuous improvement in system hardening and resiliency.

10.2.4 Infrastructure Development Programs

Infrastructure development programs are an approach designed to address the addition, replacement, and/or modification of specific assets that are in service or determined necessary to be placed in service across wide portions of the service territory. The prompts for program development or modification are varied and include items such as asset condition, operational safety, and service reliability. With the execution of most programs, the distribution system becomes more resilient/hardened to the impacts of climate change. Specific programs that have and/or are being executed with system resiliency/hardening being a significant benefit include the following:

Recloser installations

Line reclosers are devices that detect and interrupt fault current and, after a prescribed time delay, reenergize the line. As of the writing of this ESMP, the Company has installed approximately 1,900 560/800A[4] reclosers across the Commonwealth over the course of several decades. Reclosers contribute to distribution system resiliency by reducing the frequency of permanent interruptions resulting from system faults that are temporary in nature. In addition, reclosers significantly limit outage exposure when they operate to clear permanent faults, since customers ahead of the line recloser installation will not experience an outage. Fault Location, Isolation, and Service Restoration (FLISR) is a program within the Company's Grid Modernization Plan and is described further in Section 6. It utilizes line reclosers and intelligent programing to isolate faults and immediately restore service to customers in unimpacted sections. Cutout mounted reclosers function similarly to line reclosers, adding reclosing capabilities to single and three phase locations where a recloser would not typically be used for fault isolation. To date, the Company has installed cutout mounted reclosers in over 200 locations across its service territory since 2015.

Underground infrastructure

Underground distribution systems are largely insulated from storm impacts that affect overhead systems. However, increased temperatures, flooding, more frequent freeze/thaw cycles throughout the winter months, and other climate impacts can exacerbate and accelerate asset condition concerns with underground infrastructure. The Company has robust asset replacement programs in place to proactively identify and mitigate risks associated with this equipment. The Underground Cable Replacement program prioritizes underground cable replacements according to safety, customer impact if the cable were to fail, asset condition, and reliability. A separate program addresses underground cable systems that serve residential and commercial developments and exhibit a history of failures. These cable replacement/rehabilitation programs improve the resiliency of underground systems by addressing cables at a heightened risk of failure and improving the overall asset health of the system.

An example of other underground assets that have been targeted programmatically is oil fused cutouts. Oil fused cutouts are submersible fusing and switching devices used in some underground systems. These devices present a unique reliability and resiliency challenge, as safety considerations have led to the adoption of work practices prohibiting switching of oil fused cutouts with personnel in the enclosed space. Remote operating tools and procedures increase the complexity and duration of both outage restoration activities and non-emergency switching procedures. Since 2002, the Company has actively been executing a program to remove all oil fused cutouts from its system.

Flood mitigation

Flooding presents a significant environmental risk to electric infrastructure, particularly in substations. In the spring of 2010, a series of heavy rain events caused historic flooding in the state of Rhode Island. Eight substations in the Company territory were completely flooded and subsequently had to be removed from service. The impacts of this event included significant customer outages and loss of high value substation equipment. The Company recognizes the threat that floods pose to all its substations, including those located in the Commonwealth.

Following these flood events and concerns stemming from the impacts of Hurricane Irene and Superstorm Sandy, the Company completed an assessment of the likelihood of substations throughout its service territory sustaining damage during a flood event. The study compared substation locations to the flood zones in Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps. Substations located within the 100-year flood plain have a 1% probability of being reached by flood water in a given year. In these substations, the base elevation of equipment and critical buildings within the substation was used to determine how deeply they would be submerged during a 100-year flood. System impacts from a flood event could include substation

[4] This 560/800A refers to the current rating of the recloser.

removal from service and a high probability of damage to critical equipment such as transformers, circuit breakers, and relays. Customer outages would likely occur while the substation equipment is not available. Flood mitigation measures have been or are being taken at all thirteen of these substations. Mitigation measures include:

- Immediate response actions such as the installation of Timber Wall and Floodstop barriers (rapidly deployable earth-filled barriers), flood barriers, and supplemental flood risk reduction elements such as pumps, plugs, and generators to displace water inside substations from general rainfall and potential flood barrier leaks (status complete);
- Further evaluations of flood risk that resolve system performance concerns, including interactions with external agencies such as submitting a Conditional Letter of Map Revision ("CLOMR") to FEMA (status complete); and
- Incorporation of flood mitigation measures into planned infrastructure development projects at the identified substations.

These measures are intended to reduce the risk of damage during a flood event, enhancing the Company's substations' resiliency to this potential climate change impact. Flood mitigation efforts have been implemented at approximately 40 substation locations with approximately 20 additional projects planned. Section 10.4 discusses how the Company is continuing to identify additional substations impacted by increased flooding due to climate change and sea level rise.

Targeted hardening and reliability efforts

The Company conducts regular analysis of the distribution system's reliability as part of larger area study efforts and in response to acute system concerns. The Company conducts annual Engineering Reliability Reviews on a subset of circuits whose reliability metrics (frequency and duration) were in the bottom 5% of the Company's circuits for the previous year. This results in analysis of approximately 60 distribution circuits each year to identify measures that will improve their reliability and resiliency in subsequent years. The solutions typically implemented by the Company include line recloser installations, circuit reconfigurations, reconductoring bare wire with tree wire or spacer cable, FLISR installation, and targeted vegetation management. Recommendations stemming from these reviews enhance the ability of these circuits to withstand environmental conditions contributing to their relatively poor reliability and decrease the time it takes for the system to recover from damage.

Emergency response plan

Regardless of how hardened and/or resilient the distribution systems are, it is inevitable that the Company will experience and must be prepared to respond to extreme weather events that impact its infrastructure significantly. The Company has established the Massachusetts Electric Emergency Response Plan ("ERP") for the purpose of managing outages caused by storms and other natural disasters, major equipment failure, or other events. The ERP is intended to be simple, flexible, and easily adapted to specific emergencies, and includes procedures that will be adhered to by the Company whenever an emergency occurs.

The ERP provides the framework for the orderly response of Company resources during emergency events. These procedures provide instruction on actions taken during emergency events classified as Type 1, 2, and 3. The ERP uses the National Incident Management System (NIMS), which is a comprehensive national approach to incident management applicable at all levels of the Company's Emergency Response Organization ("ERO") and across functional disciplines. It is focused on public safety, workforce safety including safety of outside assistance, and addresses the operation of Company Emergency Operation Centers. The ERP meets the requirements for preparing and filing annually and incorporates regulatory orders into its development. The ERP has been developed in accordance with all applicable regulations and is designed based on the principles of Incident Command System ("ICS") and the Company's Group Crisis Management Framework. The Company conducts training, drills, and exercises on an annual basis to evaluate the effectiveness of this ERP, with the New England State Emergency Response Functional Exercise completed by August 1 of each year. The ERP is also reviewed with revisions identified and submitted to the Department no later than May 15th of each calendar year.

The ERP and its associated organizations and training allow the Company to respond effectively and efficiently to emergencies across the Commonwealth, including those caused or influenced by climate change.

Early Fault Detection

As described in Section 6.3.2, the Company is requesting funding to deploy Early Fault Detection (EFD) on a select number of circuits through the Future Grid Plan.

EFD is a technology that has the ancillary benefit of improving network reliability and resiliency by detecting and locating risks to electrical infrastructure (such as those from overgrown vegetation) before they develop into electrical faults that impact the performance of the system. EFD can be considered a form of predictive maintenance, identifying potential equipment failures, and resolving unplanned fault events before they occur, which improves the operational performance of the network and reliability for customers. As climate-related threats worsen, such as wildfires and vegetation impacts, the network visibility provided by EFD is anticipated to become even more worthwhile.

In addition to proactively addressing concerns before an outage occurs, EFD may be beneficial for restoring power more quickly for customers and reducing customer minutes interrupted. EFD enables network operators to identify the point of failure more quickly using EFD sensors and the available EFD data to isolate the fault at the component level, thus expediting the replacement of the failed equipment and restoring power for customers.

10.3 Distribution Resiliency Hardening Programs

The Company has developed a resiliency strategy which establishes an approach using existing readily available system outage data to identify, prioritize, and mitigate Company circuits that have demonstrated historical resiliency challenges. The strategy focuses specifically on hardening investments that are anticipated to increase the resiliency of the distribution system. These hardening investments include spacer cable reconductoring, targeted overhead line hardening, targeted undergrounding of single-phase side taps, and targeted undergrounding of mainline three phase conductor. The resiliency strategy proposes to invest in targeted hardening and resiliency projects through 2030. As the climate vulnerability assessment effort described in Section 10.4 progresses, it will inform future revisions to the resiliency strategy to incorporate future-looking climate projections in hardening investment decisions.

10.4 Asset Climate Vulnerability Assessment (such as Flood Impacts, Wind Speeds, High Heat Impacts, Ice Accretion, Wildfire and Drought)

Climate vulnerability assessments consider the impacts of climate change over the next several decades on assets. Understanding changing climate conditions and the risk to assets ensures appropriate mitigation efforts are considered to protect existing assets and build climate resiliency into future assets. The typical lifespan of an electrical asset is often 50 or more years, so future climate hazards need to be considered during the planning process to avoid premature asset repair or replacement. For example, the location of a proposed new substation may not be in a coastal flood prone area today, but climate model projections may indicate that it will be in 10 years. Understanding the future climate hazards will allow the making of informed design decisions and update hardening programs to protect the Company's assets and improve customer reliability into the future. Investments associated with the outcomes of climate vulnerability assessments are included in the base rate case.

10.4.1 Asset Climate Vulnerability Assessment Overview

Asset climate vulnerability assessment (CVA) is the process of using climate model projections to determine the future risk to the Company's built and future electric infrastructure for specific climate hazards. It includes understanding the geographical characteristics of both climate hazards and their assets, the vulnerability of the assets and the inherent exposure. A system-wide climate vulnerability assessment has been initiated to begin developing adaptation plans to minimize future climate hazard risk.

10.4.2 Climate Hazard Risk Overview

Climate hazard risk relates to the physical and operational impact of changing climate hazards to electric assets due to increasing chronic hazards and intensifying extreme acute hazards as a result of global warming. Climate hazard risk consists of three components, as shown in Exhibit 10.6:

Exhibit 10.6 – Climate Risk Hazard Review Calculation

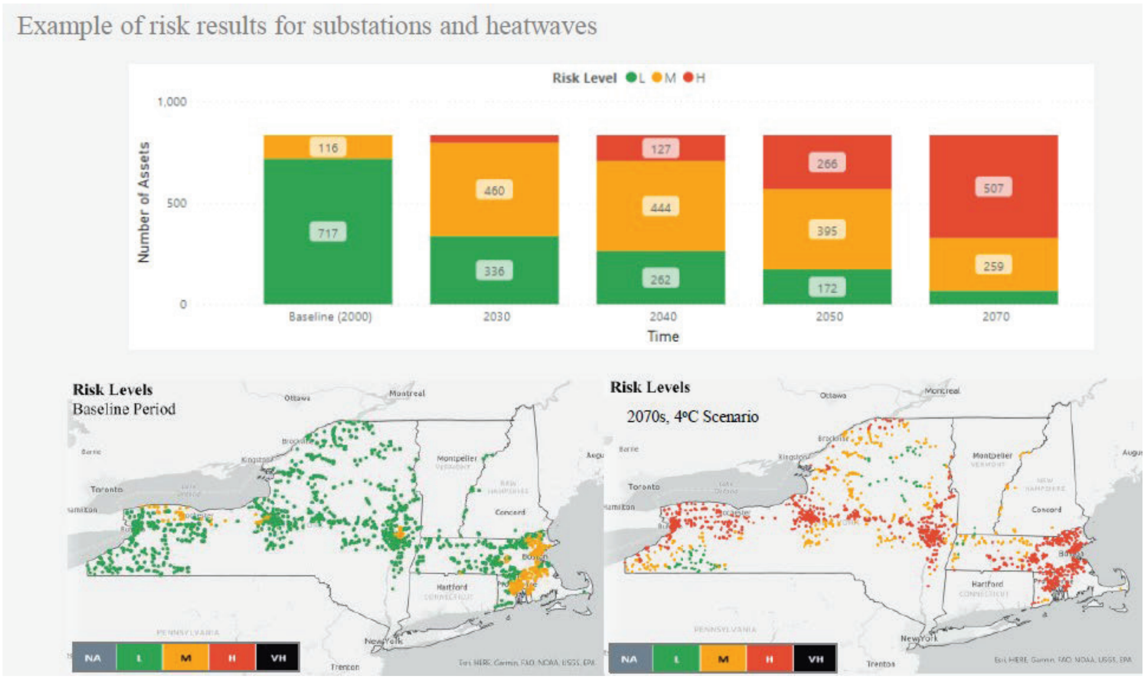
Risk = **Hazard** x **Vulnerability** x **Exposure**

Hazards are climate events which can cause damage to assets or infrastructure. Vulnerability captures the asset sensitivity to climate hazards. Exposure incorporates the asset location, relative to the hazard location.

To identify climate hazard risk, an internal tool was developed called the Climate Change Risk Tool (CCRT). The CCRT is an innovative tool that allows the Company to accurately map how their electric infrastructure may be impacted by climate hazards – such as floods or heatwaves – and to take early preventative and adaptive measures to significantly lower the risk of disruption to power networks, equipment, and communities decades into the future. The data in the tool was sourced from the Fourth National Climate Assessment (NCA4). These assessments include data from FEMA, the National Oceanic Atmospheric Administration (NOAA) Physical Sciences Laboratory, Environmental Protection Agency (EPA), and academic literature. The scenario data is modelled using the Intergovernmental Panel on Climate Change's (IPCC's) Representative Concentration Pathway (RCP) scenarios of RCP4.5 and RCP8.5. The following table includes a description of the two RCP scenarios to provide additional context.

RCP	Description	CCRT Represented Scenario
RCP 4.5	Considered an 'Intermediate Scenario' with global warming increases range between 1.1°C and 2.6°C by 2100	'2°C Scenario'
RCP 8.5	Considered a 'Worst-case Scenario' with global warming increases range between 2.6°C and 4.8°C by 2100	'4°C Scenario'

Exhibit 10.7: CCRT Output Sample Showing Long-term Projections that Risk Heatwaves Will Have to Substations.



Using the CCRT, specific assets having high risk to specific chronic climate hazards were identified. Acute climate hazards related to chronic hazards that have a high impact on electric assets were also identified through conversations with experts, current events, and available resources, but are not yet modeled in the CCRT.

10.4.3 Climate Hazards

Five primary hazards were identified (using the CCRT and other available resources) that have the greatest potential impact on the electric network. The following sections summarize the changing risk levels related to coastal flooding, high-temperature, extreme wind, wildfire, and low-temperature.

Coastal flooding

Water infiltration can significantly impact substation equipment and above-grade components of underground distribution line systems, resulting in physical and electrical failure and accelerated corrosion. Climate models are projecting a rise in sea level that leads to an increase in asset exposure risk to coastal flooding near the shoreline, expanding further inland over time. Water infiltration can significantly impact substation equipment and above-grade components of underground distribution line systems, resulting in physical and electrical failure and accelerated corrosion.

Using the CCRT, the Company can begin to assess changing risk levels at existing asset locations. Exhibit 10.8 illustrates the baseline risk for a few of the highest risk coastal substations[5]. Exhibit 10.9 shows an example of how the risk level is expected to change over time moving from low to high,

[5] Only a select few of the Company's highest risk coastal substations are shown in this map for demonstrative purposes.

where 'high' risk is defined as a 1% chance of flooding in a given year.

Exhibit 10.8 – Baseline of Substations at High Risk for Coastal Flooding

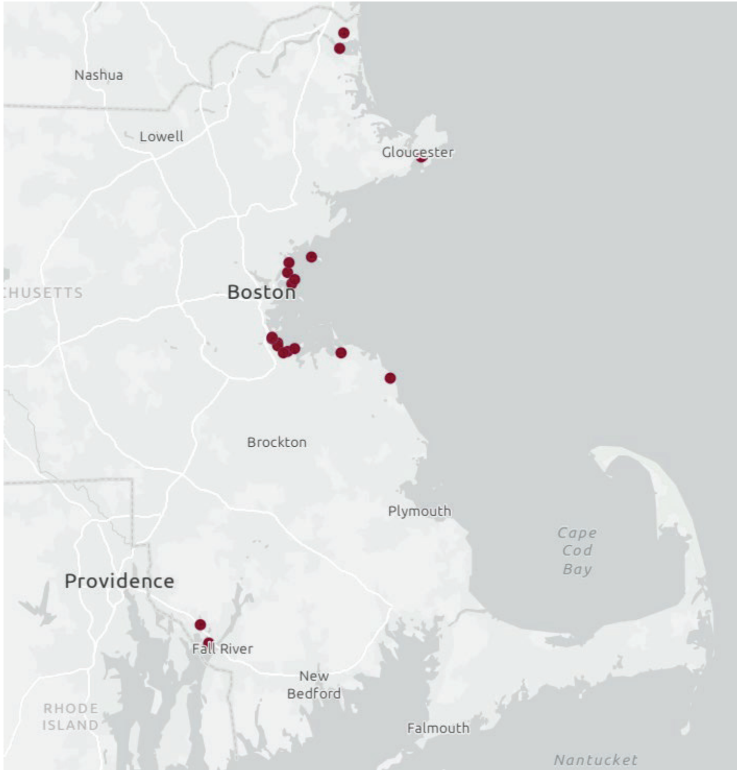
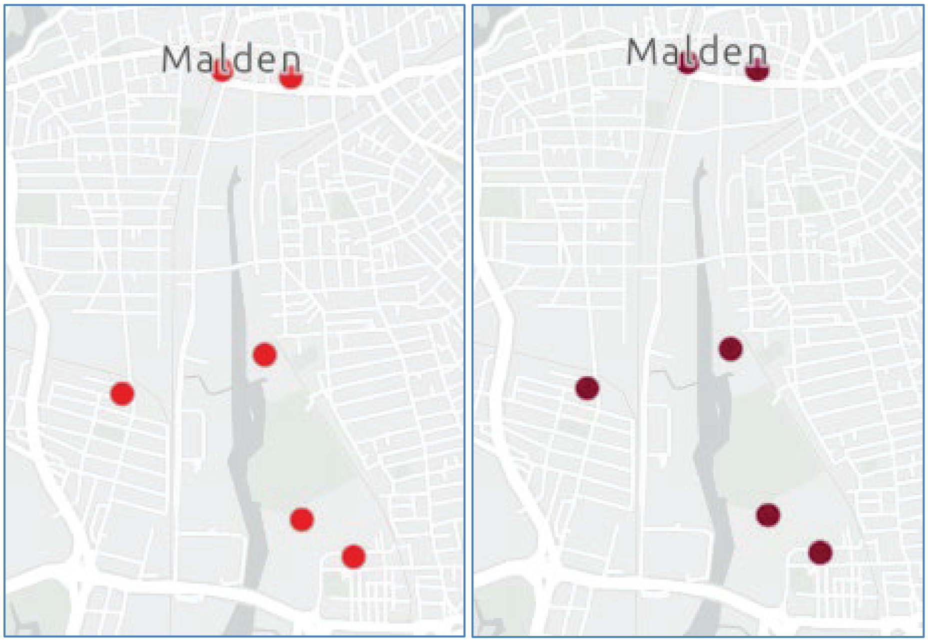


Exhibit 10.9 – Example of Substation Flood Risk Change (2-Degree Scenario)



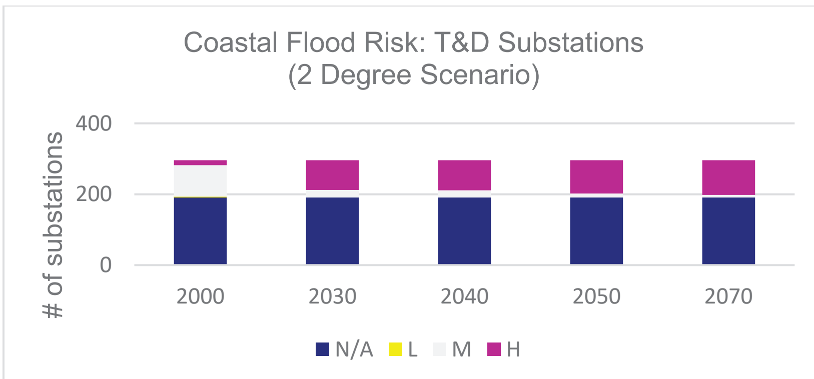
2030 (Moderate Risk) ***2050 (High Risk)***

Over the next couple of years, the Company will use this tool, along with more granular information such as the Massachusetts Climate Resilience Design Standard Tool, to evaluate each substation where flood mitigation has not yet been completed and continue flood mitigation efforts outlined in Section 10.2.4 to address future flood risks. Projects will be further assessed if a significant risk level is identified during the evaluation process.

Substations

An initial review has been completed to identify substations at risk of coastal flooding over time. The following chart, Exhibit 10.10, shows the change in substations at high risk for coastal flooding, when considering the 2-degree scenario.

Exhibit 10.10 – Coastal Flood Risk: Substations



The Company has had a significant focus on flood mitigation risk as described in the previous section. Flood risk is reviewed approximately every 10 years as FEMA maps are updated. Considering the output from the climate model, substations further inland have been identified in addition to those identified through the FEMA maps and NOAA sea level rise data. Note that the model's granularity does not evaluate elevation change at each specific substation site, so the risk must always be further evaluated at each individual site.

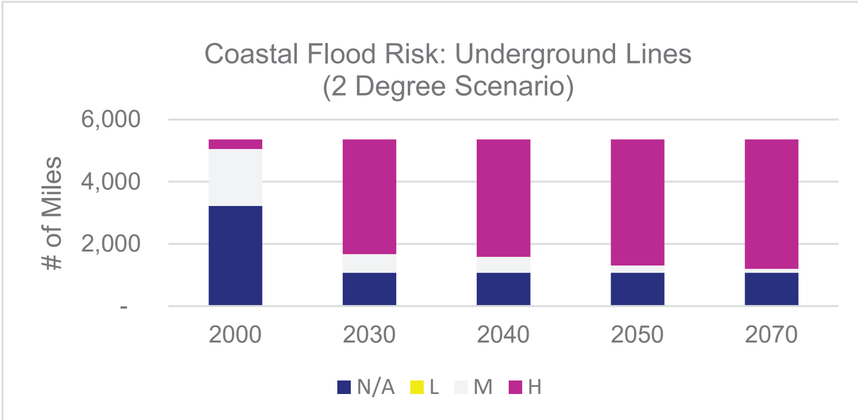
According to NASA sea level projections[6], sea level rise in Boston is expected to increase between 0.52m (RCP4.5) and 0.59m (RCP8.5) by 2070 and will be taken into consideration in the actual elevation design. Furthermore, the Company is beginning to discuss increasing their flood mitigation design criteria to a more stringent criteria to account for future flood levels above the current design standard for all planned projects as well as assessing existing flood mitigation measures.

Underground distribution lines

The CCRT identified underground lines at risk for future coastal flooding. Exhibit 10.11 shows the change in risk for coastal flooding considering the 2-Degree Scenario over time. Like substations, assets further inland are exposed to coastal flooding.

[6] Sea Level Projection Tool – NASA Sea Level Change Portal

Exhibit 10.11 – Coastal Flood Risk: Underground Lines



In general, the underground system is designed to be submersible. The above ground components of underground systems (e.g., padmount transformers and switches) are the most vulnerable to coastal flooding. To address these impacts, the primary mitigation action under consideration is to apply the coastal design storm hardening standard further inland which specifies the use of specific material and equipment types that are more resistant to corrosion and the requirement to increase elevation of electric equipment (e.g., transformers and switches).

River flooding

River flooding risk was reviewed as part of this assessment, but the models indicate only a slight increase in risk. NOAA's historical and projected precipitation[7] data was reviewed as the risk of river flooding is directly related to projected precipitation. The following table, Exhibit 10.12, includes the projected number of days per year with greater than 3" of rain.

Exhibit 10.12 – days w/ >3" rain

	Days/Year w/ >3" of Precipitation		
County	**2000s**	**2070s RCP4.5**	**2070s RCP8.5**
Berkshire	0.1	0.2	0.2
Bristol	0.1	0.2	0.3
Essex	0.2	0.3	0.3
Franklin	0.1	0.1	0.1
Hampden	0.1	0.2	0.2
Hampshire	0.1	0.2	0.2
Middlesex	0.2	0.3	0.3
Nantucket	0.1	0.2	0.3
Norfolk	0.2	0.3	0.3
Plymouth	0.2	0.3	0.3
Suffolk	0.2	0.4	0.4
Worcester	0.1	0.2	0.2

[7] https://crt-climate-explorer.nemac.org/

There is variability year to year (e.g., 0-1.5 days for Worcester County) and an extreme flood event could be seen within the Company's service territory in any given year outside the projected values. Substation sites located near rivers will continue to be reviewed for flood risk.

Heatwaves and high temperature

Increasing ambient temperature has the most significant impact on transformers, overhead line conductors, and protection and control equipment. The vulnerabilities include increased sagging, which can endanger the public, increased potential for outages and lowered electrical capacity of the line, decreased life expectancy, and decreased capacity. The following tables, Exhibit 10.13 through 10.16, show the impact temperature change can have over the coming decades for both transformers and overhead line conductors. There is a clear trend of an increase in miles of distribution lines, transformers and substations exposed to high impact temperatures. Please note the values shown in the charts are approximate.

Exhibit 10.13– Heatwave: OH Conductor

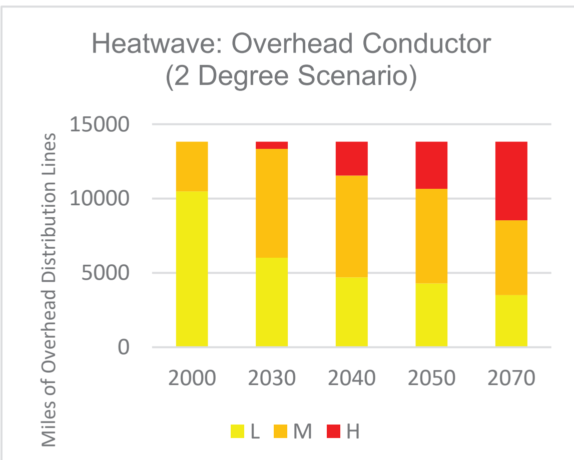


Exhibit 10.14– High Temperature: OH Conductor

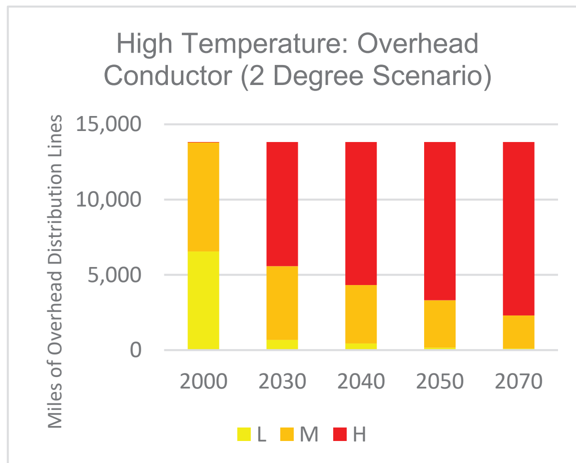


Exhibit 10.15 – Heatwave: Line Transformers

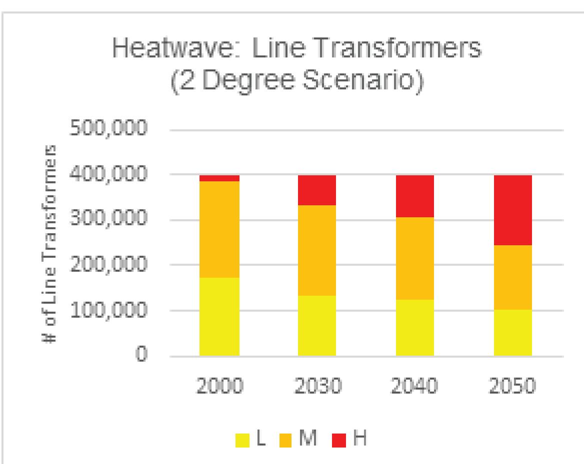
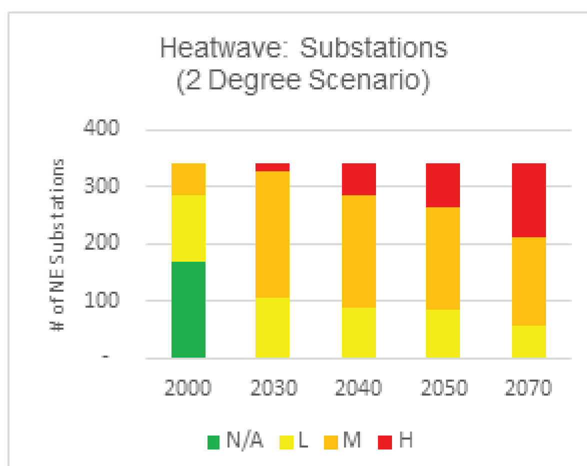
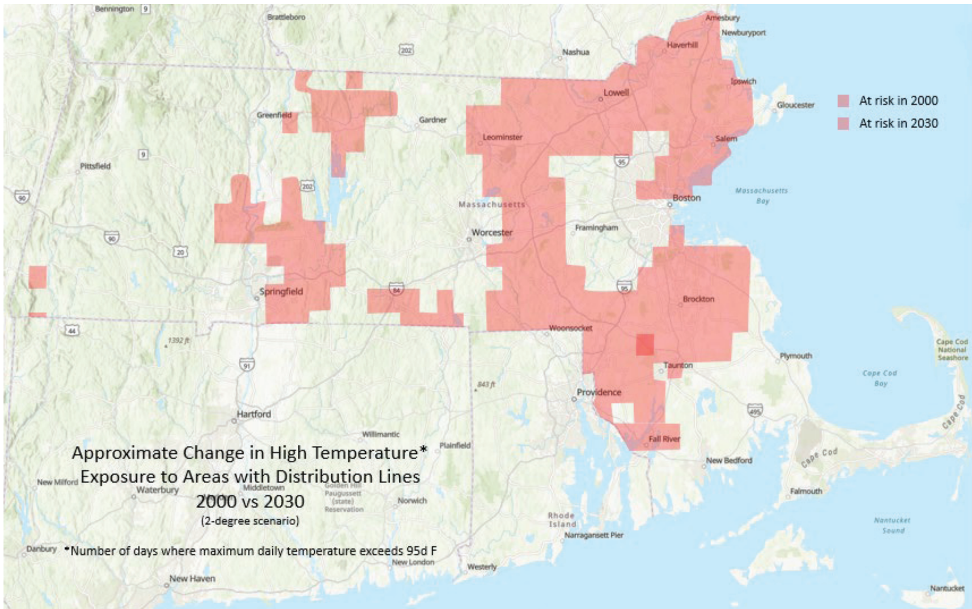


Exhibit 10.16 – Heatwave: Substations



The data above indicates more assets will be exposed to temperatures exceeding 95F over the next several decades. Exhibit 10.17 is a map depicting the difference between 2000 and 2030.

Exhibit 10.17 – Temperatures >95F: 2000 vs. 2030]



To further understand the risk of increasing temperatures, NOAA's historical and projected temperature[8] data was reviewed to better understand the frequency of high temperature events in the Commonwealth. Exhibit 10.18 includes the projected number of days per year with temperatures greater than 105F.

Exhibit 10.18 – days > 105F

County	Days/Year w/ max temp > 105F			
	2000s BL	2050 RCP4.5	2070s RCP4.5	2070s Range
Berkshire	0	0	0	0-0.3
Bristol	0	0.1	0.1	0-1.3
Essex	0	0.1	0.2	0-1.7
Franklin	0	0.1	0.2	0-3.6
Hampden	0	0.1	0.2	0-2.9
Hampshire	0	0.1	0.2	0-2.8
Middlesex	0	0.1	0.3	0-4
Nantucket	0	0	0	0-0
Norfolk	0	0.1	0.1	0-2.2
Plymouth	0	0	0.1	0-1.3
Suffolk	0	0.2	0.3	0-3.7
Worcester	0	0	0.1	0-1.7

While the average temperature increases are quite low, the variability in range shows the Commonwealth could see days with greater than 105F.

[8] https://crt-climate-explorer.nemac.org/

The development of conductor design uses a standard ambient temperature of 100F. There are ongoing conversations to determine if the ambient temperature should increase to 105F and what the impact of such a change would have on standard pole height and spacing. Additionally, a study is being initiated to evaluate transformer standard sizes considering changing demands and increasing ambient temperature. The potential impact of standard changes would be an incremental cost increase to each project ranging from <1% to 5%, once the standards are determined and implemented.

The Company will also plan to evaluate control cooling systems and control building backup power standards to minimize the impact of increasing temperatures.

The impacts of increasing ambient temperature go beyond standards and design criteria and begin to impact forecasted demand and equipment ratings.

As climate change continues to impact the Company’s customers and territory, including increased extreme high temperature days, the incremental capacity enabled through the investments described in Section 6 will provide additional flexibility to respond to these emerging resiliency challenges. Consideration of ambient temperature increases and the impact on loading will be considered further for the base forecast scenario.

Extreme wind and ice accretion

As outlined in previous sections, a robust storm hardening program has been implemented. Looking forward to projections of both extreme wind events and icing events can provide insights on how to adapt the Company's storm hardening program considering the impact of climate change.

Global

Global oceans have been remarkably warmer than they have been historically, and the North Atlantic Basin has been experiencing record high sea surface temperature. Hurricane severity is likely to increase because of high sea surface temperature, sea level rise, and atmospheric changes (e.g., warming of mid-latitudes), but the degree of intensity increase is uncertain. The frequency of hurricanes will still be driven by the oscillation between La Niña (increased hurricane activity) and El Niño (decreased hurricane activity) phases.

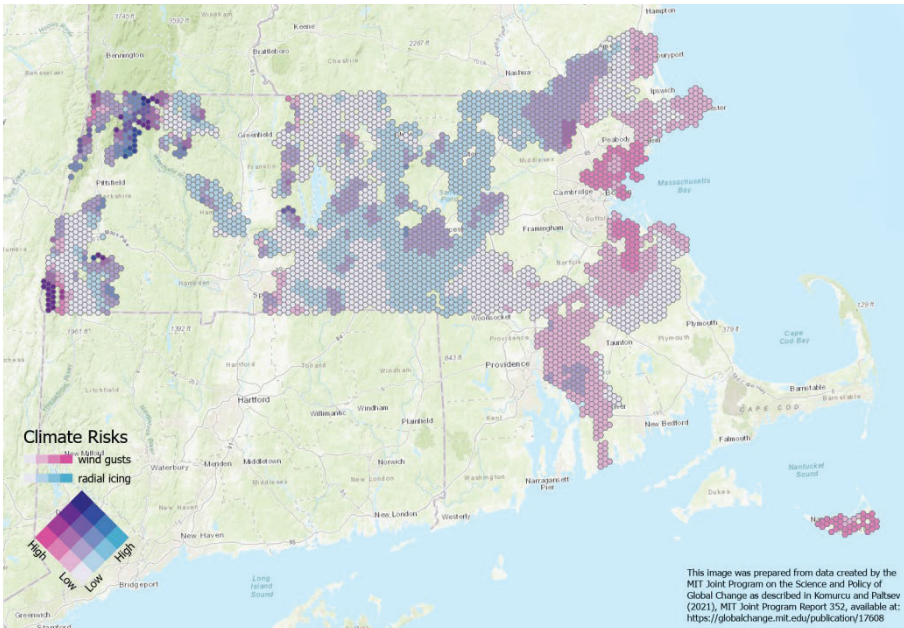
Increased air temperature can hold more moisture and therefore more precipitation is expected to fall at higher temperatures year-round. In areas prone to snowfall, there is an increasing risk of icing events as winter temperatures increase and precipitation falls around 32F.

Northeast

Because of the expanding tropics (warming of mid-latitudes), the latitude at which a hurricane is the strongest is expected to move northerly and therefore the risk of experiencing more intense winds speeds in the Northeast is growing. A study conducted by Massachusetts Institute of Technology[9] identified several regions across the Commonwealth that could see >120mph wind over the years 2025-2040. The same study also identified radial icing events over the years 2025-2040 and it concluded several areas are at risk of radial icing greater than 0.75 inches.

[9] MITJPSPGC_Rpt352.pdf

Exhibit 10.19 – Wind Gusts and Radial Icing Climate Risk Map



Note in the map above: 'High' Radial Icing (blue) is defined as 0.72" to 0.95" and 'High' Wind Gusts (pink) are defined as 98mph to 121mph

Electric infrastructure impact

Distribution lines will continue to have the highest vulnerability to extreme wind and icing events, with vegetation contact being the primary risk factor for outages. Optimized vegetation management activities, as outlined in Section 10.2, have proven to positively impact the reliability of the electric network. Tree wire, anti-cascading structures, and FLISR schemes will further minimize the impact when tree contact does occur.

Adaptations Under Consideration:

As more severe and intense weather is projected, hardening programs and standards should adjust accordingly. While there is a robust hardening program in place today, there are additional enhancements under consideration to adapt to future climate hazards:

Pole Design

The current extreme wind pole design is based on the NESC Rule 250C. For poles in southern coastal Massachusetts and those greater than 60 feet, a maximum wind speed of 120mph is used. For locations further north with less wind, and for poles less than 60 feet, a wind speed of 40mph is used. Distribution lines are also designed for 0.5 inches of radial icing concurrent with a 40mph wind. The impact of increasing wind speed and radial icing is under review and acceptance of this standard would likely result in taller, higher-class (stronger) poles.

Fiberglass Crossarms

Fiberglass crossarms are currently specified for dead-end crossarms to prevent the impacts of a cascading failure. The impact of expanding the use of fiberglass crossarm instead of wood crossarms in additional locations will be evaluated.

- Fiberglass crossarms are currently specified for dead-end crossarms to prevent the impacts of a cascading failure. The impact of expanding the use of fiberglass crossarm instead of wood crossarms in additional locations will be evaluated.

Targeted underground

Targeted underground continues to be discussed and evaluated as an option to harden the distribution network. Initial targeted undergrounding opportunities have been identified through Resiliency Strategy investments described in Section 10.3. The Company will continue to consider undergrounding opportunities to mitigate emergent climate risks, operational challenges, and reliability/resilience performance concerns focusing on communities identified above. This preliminary review of future wind and ice projections indicates Berkshire County is at highest risk for both hazards and additional targeted underground will be explored in this area in future years. The following table, Exhibit 10.20, provides an overview of distribution line assets located in Berkshire County.

Exhibit 10.20 – Berkshire County Distribution Lines

Berkshire County	
OH	**Mileage**
3 Phase	379
1 Phase	565
Total	943
Underground	**Mileage**
3 Phase	51
1 Phase	157
Total	208
Total Mileage	1151

The expansion of distribution infrastructure through the execution of the Future Grid Plan will introduce feeder routing constraints which, when combined with resiliency concerns in alignment with the climate vulnerability assessment, may lead to an increase in underground infrastructure. Distribution undergrounding opportunities are often best suited in congested areas of the system, near substations, and in highly populated areas. Underground infrastructure in close proximity to substations improves the reliability and resilience for the highest number of customers compared to undergrounding portions of circuits further from substations.

Wildfire

The current risk of wildfires in the Commonwealth is low[10] but with increasing extreme events across the US, it is an emerging risk under review. While precipitation is expected to increase in future years [11], some predict the precipitation will fall more intensely during shorter periods of time, meaning there will likely be longer periods of seasonal drought. The Company is beginning to review this risk now and expects the review to continue over the next year and will consider best practices from peer utilities in California. Vegetation management programs, inspection and maintenance programs, and storm hardening programs (e.g., tree wire and targeted undergrounding) are significant components of published leading wildfire mitigation plans to help mitigate wildfire risk. Emergency response plans are another key component which include training, exercises, communication strategy, and emergency de-energization protocol among many other activities. The Company will continue to review these best practices and will implement mitigation measures appropriate for the geographical risk level.

[10] Map | National Risk Index (fema.gov)
[11] Climate Explorer (nemac.org)

10.5 Framework to Address Climate Vulnerability Risks through Resilience Plans

The Company is committed to taking proactive action to address the impacts of climate change on the electric system. Climate change is no longer a "future threat". Its effects, including observable changes in average temperatures, precipitation trends, and extreme weather events, are being witnessed today. Climate change is anticipated to give rise to more frequent extreme events and utility providers must plan for their potential effects. The Company's framework to address climate vulnerabilities is outlined in the phased approach in Exhibit 10.21, and the identified adaptations are included in resilience plans as described in Section 10.4.

Exhibit 10.21 – Framework for Vulnerability Risk Assessment

- **Phase 1:** Validate the climate science, climate hazards and assets in scope
- **Phase 2:** Assess the vulnerability of each asset to each climate hazard
- **Phase 3:** Prioritize the assets identified in Phase 2 using the following framework: Climate Vulnerability Risk = Exposure x Potential x Hazard
- **Phase 4:** Develop adaptations to address assets with the highest risk

The process follows the Institute of Asset Management (IAM) guidance for climate change action planning. For developing climate change adaptation plans, the IAM recommends the use of risk-based models, considering the increasing likelihood and consequence of asset failure or degradation due to climate change and the impact this might have on the delivery of the organization's goals. If unaddressed, the climate vulnerabilities identified could have significant implications for the Company assets and its ability to deliver affordable, safe, and reliable electricity to its customers. Projected changes in temperature, heatwaves, flooding risks, and extreme events that lead to high wind speeds, storms, and icing may aggravate rates of asset failure, and cause more outages, thus impacting system reliability. These impacts could also mean increased operational as well as repair and restoration costs. In addition, these impacts may raise concerns around workforce and public safety. This framework will highlight priority areas where the Company can focus its future climate resilience planning and investments decisions.

Through the initial climate vulnerability assessment, it can be concluded that more severe and intense weather will be experienced in future decades, and hardening programs and standards should adjust accordingly. Most of the adaptations under consideration are likely to be in the form of standards updates such as increased pole strength, increased ambient temperature, and expansion of coastal flood design which would be applied to all new and replaced assets once the standard is implemented.

Targeted adaptations, such as permanent and temporary flood mitigation, are prudent to plan for now. As a result of the climate vulnerability assessment, the Company plans to invest in additional temporary flood mitigation projects at five substation locations as part of "electric operations" in the "base" rate case. The substations will be selected following site-specific evaluations. Temporary and permanent flood mitigation will be planned for the remaining substations in future years.

Climate projections can shift over time and the risk of climate hazards to the Company's infrastructure must continue to be assessed. Annual funding will be requested in the base rate case to maintain and improve the functionality of the CCRT to ensure continual climate model updates and asset risk evaluations.

Finally, the Company will continue to learn from the climate vulnerability assessment and the planned targeted underground projects to identify additional opportunities to underground distribution lines in future years.

The Company acknowledges that while the findings from the assessment are critical to resilience planning and investment decisions for the next 5-20 years, the vulnerability of its assets to different climate hazards will continue to evolve. This assessment must therefore be seen as part of an ongoing process through which the Company will regularly evaluate and adapt its resilience planning into the future.

As noted above, as climate change continues to impact the Company's customers and territory, including increased extreme high temperature days, the incremental capacity enabled through the investments described in Section 6 will provide additional flexibility to respond to these emerging resiliency challenges.

Section 11
Integrated Gas-Electric Planning

This section describes of the importance of integrated planning across gas and electric utilities and provides a pathway to begin advancing such planning in the Commonwealth.

Key Take-Aways

- Integrated energy planning across EDCs and gas LDCs will become increasingly important as the Commonwealth pursues the electrification of heating. An orderly transition of customers to electric heating allows for benefits such as avoiding gas infrastructure investment via targeted electrification of gas customers and ensuring the local electric network is ready to pick up the load.
- The status quo presents challenges to integrated planning including lack of service territory overlap among EDCs and gas LDCs, historically siloed planning processes, and lack of regulatory and policy enablers.
- Kicking-off concerted collaboration efforts across the Commonwealth's EDCs and gas LDCs with other key stakeholders is an important first step.
- Pathfinding work to define integrated planning capabilities, pilot them, and scale them should start soon, and the Future Grid Plan seeks initial seed funding for such work.

11.0 Integrated Gas-Electric Planning

What is integrated gas-electric planning and why is it needed?

Transitioning from fossil fuel heating to electrification is a critical component to a decarbonized future. Today, however, much of the Commonwealth relies on natural gas for space and water heating as well as cooking. Electrification policies and programs need to direct Massachusetts homes and businesses toward electrification when the opportunities arise (e.g., at end of life for a legacy fossil heating system). By forecasting growth in comprehensive electrification demand and investing in electricity system capacity to serve that demand, the EDCs can enable that electrification transition for customers. With this transition to electrification, there is an opportunity to fine-tune decisions across customer demand-side programs, electricity network investments, and gas network investments to provide for a more reliable and affordable whole energy system.

In its recent D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, the Department explained that it "agrees that coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition" and explained that "gas and electric infrastructure planning will be necessary as consumers transition from using fossil fuel-based heating systems to electric heat pumps."[1]

Gas and electric utilities generally plan and operate their networks in isolation from one another, even when they are affiliated companies with a common parent company, because historically there has been little need for coordination. Moreover, customer demand-side programs have been only loosely integrated with infrastructure planning. Integrated energy planning (IEP) will be essential to achieving the Commonwealth's decarbonization goals and mandates while providing gas and electric customers with safe, reliable, and affordable service during the transition. For example, the full electrification of gas customers not coupled with the necessary electric infrastructure improvements will result in an unreliable grid; conversely, there may be opportunities to locally target deployment of heat electrification in ways that avoid gas network investments. The LDCs and EDCs are uniquely positioned to work collaboratively in development of the ultimate electric distribution and gas infrastructure plan necessary to meet the Commonwealth's decarbonization goals. An orderly transition to decarbonization that includes coordination and collaboration on gas and electric system planning and customer demand-side programs outside of traditional measures offers several potential solutions to optimize overall energy system costs and reliability:

- Gas utilities may be able to avoid network reinforcements if targeted electrification can address gas load growth in the near term, which might require accelerated electricity network heat load-serving capacity investments;
- Targeted electrification could be an alternative to leak-prone pipe replacement if electricity network capacity can support the incremental load in time;
- In locations where electrification adoption is exceeding the electrification hosting capacity, hybrid gas/electric heating solutions could be useful to maintain system reliability. The entity delivering demand-side programs will need to be aware of these constrained areas and work with customers to develop the hybrid solutions;
- Correspondingly, in areas where the pace of electrification adoption is projected to exceed the electrification hosting capacity, the electric companies may need to accelerate electric improvement plans in those areas.

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[1] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 131.

The purpose of IEP is to help realize these benefits. IEP will collectively help enable the Commonwealth to:

a. Prudently build out the electric system in the right locations at the right time to prepare for conversion of fossil fuel-based heating to electrification and;

b. Make calculated decisions about where on the gas system to prioritize investment in the gas network (e.g., leak-prone pipe repair or replacement) and/or plan to decommission sections of the gas network in favor of electric heating or alternative heating solutions, such as networked geothermal.

IEP is the 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. Likewise, the Department concluded in D.P.U. 20-80-B that "going forward, evaluation of any proposed investments [by gas LDCs] will have to take place in the context of joint electric and gas system planning."[2]

The Company has undertaken steps already to explore how IEP could be done and to engage broadly with industry and other stakeholders to gather insights and lessons learned from burgeoning IEP efforts across North America and internationally, including:

- The Company has sought out peer utilities in North America, the United Kingdom, and Europe with advanced efforts on IEP in order to solicit input and derive insights from their work, including learning from the Company's affiliates in the United Kingdom.
- The Company has explored new software tools that could enable IEP, in collaboration with its affiliates.
- During 2022 and 2023, the Company worked with its gas LDC affiliate, Boston Gas Company, on a novel IEP "desktop" engineering exercise that looked at two cities with overlapping National Grid electric and gas service. The exercise analyzed the electric network infrastructure impacts of fully electrifying gas load and zoomed in on particular segments of leak prone pipe to identify potentially promising segments where customers, in theory, might be fully electrified and the leak prone pipe segment decommissioned in lieu of replacement. The purpose of the exercise was to better understand IEP capability enablers—e.g., process, methodology, key assumptions, and data.
- The Company has engaged in discussions with the Department of Energy Resources, MassCEC, and consultants from Groundwork Data, including to provide feedback on approaches to local-level integrated planning.
- The Massachusetts EDCs have convened multiple times to discuss IEP—including: their respective early engineering studies, potential approaches to stakeholder engagement, Eversource's IEP concept described in its ESMP, and potential collaborative pilots.
- In October 2023, the Company's gas LDC affiliate, Boston Gas Company, explained in its annual Gas System Enhancement Program filing that it is developing a targeted electrification pilot project using IEP.[3] The scope of the pilot project is to decommission one or more segments of leak-prone pipe and fully electrify energy use with air source heat pumps for all customers currently served on those leak-prone pipe segments. The Company has been collaborating with its gas LDC affiliate on developing this pilot project.

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[2] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 131.

[3] Petition of Boston Gas Company d/b/a National Grid for Approval of 2024 Gas System Enhancement Plans, D.P.U. 23-GSEP-03, Exhibit NG-GPP-1, at 14.

- In October 2023, experts from the Company published the article, "Integrating Gas and Electric System Planning to Facilitate Decarbonization," in *Public Utilities Fortnightly*.[4]
- In December 2023, National Association of Regulatory Utility Commissioners (NARUC) President Julie Fedorchak named Mike Calviou, National Grid Group Head of Regulatory Strategy, to represent the electric utility sector on NARUC's new Gas-Electric Alignment for Reliability (GEAR) initiative.[5]
- In January 2024, the Company submitted a response to MassCEC's Neighborhood Electrification Request for Information (RFI) addressing "the strategic electrification of the building stock and decommissioning of the natural gas system in defined geographic areas."[6]

While the Company has been actively engaged in pathfinding work on IEP, IEP nonetheless presents new and challenging questions that the EDCs look forward to collectively addressing together, in partnership with Commonwealth stakeholders and the other electric utilities, gas utilities, and municipal electric companies.

11.1 Challenges in Considering Integrated Gas-Electric Planning

As highlighted in prior sections, multiple areas of the electric distribution system are at or nearing reliability limits and 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 face investment needs for reliability and safety. Traditionally, planning of the gas and electric systems has been bifurcated. There is now a systems convergence as heating and transportation sectors transition to the electric sector. Further complicating this is that gas and electric footprints of affiliated EDCs and LDCs do not completely overlap, necessitating integrated planning to be coordinated across non-affiliated utilities – and their associated electric and gas network upgrade plans. Below are key challenge areas that need to be overcome:

1. **People, process, technology:** While utilities have planning staff on gas and electric sides, their skillsets, the tools they use, the planning standards, and the overall capital planning processes across utilities and even between affiliated EDCs and LDCs are different. And this is to be expected with past practices requiring little to no coordinated planning efforts even across affiliated operating companies. An early challenge in kicking off coordinated gas-electric planning is to assess these differences through a common understanding and drive alignment such that a foundation for coordinated planning between the EDCs and LDCs across utilities can be established. Moreover, beyond the need to understand the current state of gas and electric system planning, there is not yet a widely accepted definition of the "future state" for IEP—i.e., what will IEP need to accomplish once fully mature.

2. **Limited service-territory overlap:** To understand the limited degree to which affiliated gas and electric utilities' service territories overlap, it is helpful to look at the share of gas customers served by the affiliated EDC since electricity service is universal. Only 28% of Boston Gas Company's gas customers are also the Company's electric customers. Given this limited level of overlap between affiliated utilities' gas pipeline networks and electric networks and vice versa, the need for coordinated utility planning is critical. For example, when a gas LDC identifies a constraint on its gas system, in order to reduce that gas demand with deployment of

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[4] See https://www.fortnightly.com/fortnightly/2023/10/integrating-gas-and-electric-system-planning-facilitate-decarbonization.

[5] "Industry Leaders Tapped for NARUC Gas-Electric Working Group," NARUC Press Release, December 13, 2023, available at https://www.naruc.org/about-naruc/press-releases/industry-leaders-tapped-for-naruc-gas-electric-working-group/.

[6] See https://www.masscec.com/neighborhood-electrification-RFI.

electrification solutions, an unaffiliated EDC may need to upgrade its electric infrastructure – necessitating a comprehensive data exchange between the gas LDCs and EDCs regardless of their parent company affiliations.

3. **Customer adoption:** Electric and gas utilities can transform their capabilities for IEP with the most robust processes, software, and data for developing plans, but actually realizing the benefits from IEP depends on implementing a deliberate and orderly transition of customers off of gas usage, at least in specific areas by specific times. The best plans to optimize across gas and electric network investments will come to naught if customers do not adopt electrification and do not transition from gas usage when and where needed. For example, decommissioning a segment of leak-prone pipe requires that every individual customer on that section of pipeline disconnect from gas and install new electric equipment (or other non-gas solution) by a certain date.
    a. The current approach to demand-side electrification incentive programs does not provide for this orderly transition because time-bound, universal adoption of electric measures (e.g., EHPs, electric boilers, electric stoves) by customers served by specific gas infrastructure is a new objective that raises important program design and implementation questions that will need to be addressed. Specifically, should new incentives be designed in gas-constrained areas, or is that a prioritization and an extension of the existing customer demand-side programs? If the latter, thoughtful consideration needs to be given to achieving the universal adoption of EHPs in those areas within the allotted time.

    b. While an organic customer adoption of electrification solutions is imperative for a sustainable path toward decarbonization, to drive an orderly transition, more coordination is needed to ensure available electric infrastructure and electrification load-serving capacity is calibrated with electrification deployment. For many gas heating customers, adoption of electric technologies at current retail rates will in most instances increase their overall energy burden. Therefore, where applicable, rate redesign may also be necessary to ensure an affordable transition to electrification.

    c. This is an area that the utilities look forward to hearing stakeholder feedback on, in the context of the ESMP. Moreover, the Mass Save Program Administrators are committed to developing ways to best address the equitable adoption of EHP technology and other EE technologies and will continue to develop these proposals in the EE Three Year Plans, in concert with the EEAC and Equity Working Group members and subject to the approval of the Department.

4. **Novel questions:** IEP 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. Moreover, the regulatory and policy frameworks in place were not designed to enable IEP. 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 IEP, including by targeted electrification of gas network segments where there will be sufficient electricity network hosting capacity based on the ESMPs. This information can inform the gas utility planning processes and will pave the way for initial information sharing on the status of the 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 (i.e., locations where there will be network reinforcement to readily support more EHP adoption), which can be used to inform review and feedback on gas utility investments and the Commonwealth's comprehensive electrification policies and programs. 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.

More specifically, this ESMP provides a 10-year view of available electrification load-serving capacity in each sub-region served by the Company within the Commonwealth. And because of various upgrades implemented in different years within the 10-year period, a sub-region's available electrification hosting capacity may increase over the forecasting period.

11.3 Coordinated Gas-Electric Planning Process

The EDCs have spent time engaging with leading peers across North America, the United Kingdom, and Europe on IEP and conducting preliminary internal engineering studies to gather insights on how such planning could work in practice. While some utilities, states, and countries are leading the way, they are all still in a pathfinding mode. No one has figured it all out yet.

Although the ultimate process still needs to be fully defined based on pilots, learning, and stakeholder collaboration, several things seem clear about how IEP should work:

- Understanding where electricity networks have sufficient headroom presently and in the future to handle localized incremental heat electrification demand and where the networks face localized constraints will be important for gas LDCs as they comply with the Department's directives in D.P.U. 20-80 regarding evaluating future gas system investments against non-pipe alternatives—i.e., "going forward, [gas] LDCs will have the burden to demonstrate the consideration of [non-pipe alternatives] as a condition of recovering additional investment in pipeline and distribution mains."[7]
- The pace and prioritization of specific electricity network investments should be based in part on identified opportunities to avoid gas system investments where accelerated comprehensive electrification can avoid gas network reinforcements or allow for targeted decommissioning of gas assets.
- Utilities should find discrete opportunities to pilot non-pipe alternatives where electricity networks can support universal comprehensive electrification (or other gas network disconnection) to decommission gas segments or avoid gas network reinforcement.
- Orderly customer adoption is necessary to realize the benefits of IEP:
    - Customer demand-side programs should be coordinated with gas/electric investment plans, including to target comprehensive electrification where it reduces overall system costs;
    - New policies and regulations may be needed to facilitate universal gas network customer disconnection in targeted areas to allow for strategically decommissioning gas assets (e.g., leak-prone pipe infrastructure).
- Where specific gas constraints are identified and electrification hosting capacity is unable to be increased in the required time such that electrification of customer loads could resolve the

[7] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 15.

gas constraint, alternative solutions (e.g., increased adoption of EE, flexible battery storage, green hydrogen), and other customer-side decarbonization solutions may be necessary.

- Further, where communities are opting for a moratorium on gas or where existing gas infrastructure is constrained, and corresponding practical moratoriums are in effect, new electric technology pilots could help further the communities' decarbonization goals – thereby avoiding new gas infrastructure.
- Stakeholder input will be essential to coordinated planning, including giving affected communities a voice in the planning.

As an evolving and novel capability, IEP will require changes to utility processes, people, and technology, as well as enabling regulatory and policy frameworks and new means for customer and community input. More work is needed to detail out what a mature IEP capability will require, but some likely initial requirements are below:

Process:

LDC-EDC Data Exchange

- Detailed data on legacy Commonwealth building stock and electrification suitability and anticipated demand
- Exchange of residential and commercial hourly heating usage data – translated to distribution feeder electrification data (accounting for weather conditions, technologies and building envelop ratings – current and forecasted)
- Exchange of gas and electric capital investment plans by year between EDCs/gas LDCs with supporting planning analyses

Joint Utility Planning Working Group

- Establishment of Joint Utility (gas LDC and EDC) Planning Working Group
- Ongoing Working Group Meetings – formal meetings to be established every 2 months with broad stakeholder participation
- Ultimate objective would be to enable development of coordinated EDC-LDC capital plans

Planning Tools:

- Software tools that translate localized gas demand with consideration of various weather associated gas demand scenarios into electric system loadings – with embedded assumptions of different electrification technologies.
- Translating those granular electric loading scenarios into distribution planning models

People:

- While LDCs and EDCs are staffed to develop their respective investment plans in the traditional way, executing on the coordination process laid out above, engaging with stakeholders on IEP, delivering on IEP pilots, soliciting customer and community input on plans, and providing visibility to the Department on IEP will require incremental staff for the EDCs and LDCs.

The EDCs and stakeholders should think through and define a long-term "future state" for IEP—i.e., what IEP delivers once it is a fully developed capability for overall energy system optimization, with enabling policy and regulatory frameworks and supporting customer and community input and engagement. However, that long-term view should not get in the way of making tangible progress in the near term. IEP will be an evolution over years. Near-term efforts can identify where looking across electricity and gas network investments and customer demand-side programs in new ways can improve pending investment decisions. One example of a near-term opportunity is the need for both affiliated and non-affiliated overlapping gas LDCs and EDCs to collaborate on exploring non-pipe alternatives to gas network investments and targeted electrification pilots, where the Department's order in D.P.U. 20-80 "directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory."[8]

11.4 Safe and Reliable Gas Infrastructure

In the near term before comprehensive electrification and other policies and programs fully slow, stop, and reverse gas demand growth, gas utilities will have network reinforcement needs to accommodate this near-term demand growth. Even more importantly, any scenario for transitioning customer demand from natural gas to electric heating takes decades to implement, during which time 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.

There may be "low-hanging fruit" to address first via IEP to identify localized gas network reinforcements driven by demand growth and relatively isolated leak-prone pipe segments slated for replacement that could be avoidable via targeted electrification. IEP offers the potential to leverage targeted electrification to avoid some of these gas infrastructure investments.

11.5 Gas-Electric Coordinated Planning Working Groups (Goals, Objectives, Actions and Timelines)

Cross-commodity coordination among peer utilities, including investor-owned and municipal utilities is essential to the effectiveness of integrated gas and electric planning. However, it is not enough to have utilities working together; the development of a scalable and enduring IEP capability and enabling regulatory and policy frameworks requires more extensive stakeholder collaboration.

Thus, establishing a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, DOER, AGO, and key affected stakeholders (e.g., environmental, consumer) will be critical. The Department endorsed such a stakeholder-focused approach in the recent D.P.U. 20-80 order, explaining that "[t]he Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome" and that "[t]he LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process."[9]

The working group's objectives should include the following:

- Develop a shared understanding of the overlapping utilities' networks today and their "current state" network planning processes
- Leverage learnings and best practices from other leading utilities in this space (e.g., California, UK, Québec, Europe)

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[8] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 15.

[9] D.P.U. 20-80-B *Order on Regulatory Principles and Framework*, at 131.

- Define a “future state” ambition for IEP
- Conduct joint gas-electric planning studies to generate learnings and identify near-term opportunities to optimize investments:
    i. Exchange of gas and electric distribution constraints
    ii. Conduct and share planning studies to resolve constraints
    iii. Detailed investigation of gas-customer electrification scenarios to assess resulting electric infrastructure constraints and corresponding assessment of offsetting gas constraints
    iv. Identification of specific gas and electric planning solutions
- Develop a shared understanding of required IEP capabilities including changes needed in processes, technology, people, and data
- Agree on a prioritized roadmap to develop such capabilities (i.e., what are “low-hanging fruit” to focus on first, and what are the transformational capabilities to go from IEP “light” to more comprehensive plans in the longer term)
- Establish an analytical framework for assessing the benefits of IEP
- Provide recommendations for how the three-year EE program process should align with IEP
- Identify needed policy and regulatory enablers for IEP
- Explore how best to provide transparency and opportunities for input to various stakeholders

11.6 Next Steps

Pending Department review of the stated objectives, proposed process, and approval of investments in people, process, data, and technologies necessary to execute on IEP, the EDCs will: (1) proceed with the establishment of the Joint Utility Planning Working Group, including reporting out to GMAC on an agreed upon cadence; and (2) pursue the near-term opportunities to engage in IEP, particularly EDC and gas LDC collaboration on non-pipe alternatives and targeted electrification pilots.

Section 12
Workforce, Economic, and Health Benefits

This section provides an assessment of how the Company's proposed Future Grid investments contribute to workforce, economic development, health, and climate benefits.

Key Take-Aways

- The Future Grid Plan will bring significant environmental, climate, health benefits and economic benefits at the state level.
- The Future Grid Plan investments will result in increased economic activity on the order of $1.1 billion and create an additional 8,700 jobs throughout the Commonwealth.
- The Company already pays nearly $240 million in state and local property taxes, and the additional infrastructure build-out under the Plan will lead to incremental tax revenue, including for local communities.
- The Company has a multi-pronged workforce development strategy focused on EJCs that will provide a talent pipeline from these communities.

12.0 Workforce, Economic, And Health Benefits

12.1 Overview of Key Impact Areas

The Company's Plan will enable climate, economic, workforce, and health benefits for the Company's customers and the Commonwealth. The Company worked with a third party to develop a comprehensive net benefits analysis that examines the quantitative and qualitative benefits of its ESMP. The net benefits analysis finds that the proposed ESMP investments will yield an estimated $821 million (present value) in quantified net benefits from investments completed between 2025 and 2029. In addition, the Company's proposed ESMP investments will help facilitate the achievement of the Commonwealth's climate goals by enabling significant levels of electric vehicles (EVs) and heat pump adoption, timely integration of DERs, and encouraging customers to shift energy consumption to avoid renewable energy curtailment, while maintaining safe and reliable service. Additional information on the net benefits analysis can be found in Section 7.1.4.

Additionally, the Company conducted a jobs and economic impact analysis using the BEA's RIMS II Multipliers model to estimate levels of economic activity and job creation, which found that up to $501 million of economic activity and 3,939 full- and part-time jobs could be created over the first five years resulting from the proposed ESMP, as discussed in Section 12.4. This impact grows to $1.668 billion of economic activity and 13,113 jobs when considered under the scope the Company's total investments for the 5-year period. To successfully execute this plan, the Company must be able to attract and retain the talent necessary to construct, operate, and maintain an evolving energy system. In Section 12.3, the Company provides an overview of its workforce development program strategy, efforts to date, and future plans, which includes a proposed program to accelerate the training and hiring of a diverse and skilled workforce from the communities we serve.

The decarbonization efforts enabled by this Plan will work to advance the Commonwealth's climate goals and improve health outcomes through the reduction of greenhouse gases and air pollutants. These health benefits are discussed in Section 12.5. Health benefits can be particularly impactful for Environmental Justice Communities (EJCs), who are disproportionately affected by air pollution.

12.2 Jobs Training and Impacts to Disadvantaged Communities

Across the Commonwealth, the Company's electric and gas businesses directly employed approximately 6,200 employees during fiscal year 2022. These direct jobs support the energy networks as they exist today. To build the electric distribution network proposed within this Plan, additional talent will be needed in sectors directly associated with the construction and operation of electrical infrastructure.

Across several recent analyses and plans, including those commissioned by the Commonwealth, projections indicate that there will be significant growth in employment needs in the electric sector:

- The **Commonwealth's 2050 Decarbonization Roadmap Study**[1] projections indicate that approximately 10,000 net electric transmission and distribution jobs in 2040 and 18,000 net jobs in 2050 will be needed to deliver the targets from the "All Options" pathway.

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

- **MassCEC's Workforce Needs Assessment**[2] projected that statewide, the transmission and distribution sub-sector would need to more than double its clean energy Full Time Equivalent (FTE) count between 2022 and 2030, growing 137% from 2,760 to 6,554 FTEs. This includes workers needed to execute the projects described in the ESMP in addition to laborers supporting other functions across the Commonwealth.
- Under the **Commonwealth's CECP for 2025 and 2030,**[3] the electricity sector is projected to be the largest source of energy employment growth, adding 10,700 net jobs by 2030 and 34,300 net jobs by 2050 from the 2019 baseline. Of these jobs added to the electricity sector by 2030, most are in the construction industry. Between 2019 and 2030, the construction sector is estimated to add 5,200 construction jobs, or 48% of the net employment gains for the sector.

These studies reinforce the estimates made for this Plan using the BEA's RIMS II Multipliers, which estimated that the proposed ESMP investments could create approximately 3,939 full- and part-time jobs for the period 2025 – 2029 and approximately 8,766 full- and part-time jobs for the 10-year period of 2025 – 2034. This calculation is further discussed in Section 12.4.

These estimates all point to the growth of employment associated with the energy transition, particularly for electric networks. Building the grid of the future will require significant growth in construction employment and associated sectors, supported by engineering, IT, and other support functions. Jobs will also be created in other energy subsectors as additional growth is enabled in transportation electrification, building electrification, renewable energy, and ESS.

Identifying, engaging, and training the diverse talent necessary to support the proposed investments for the next five and ten years will require significant effort from the Company, as well as by the clean energy economy as a whole. The Company engaged in a robust strategic workforce development effort that will enable us to identify and develop talent to support our proposed investments, particularly from populations that are underrepresented in our current workforce, as described in Section 12.3. The jobs created through the Plan will be a mix of temporary and permanent jobs, and will include union, non-union, and management roles. Section 7.3 also discusses how the Company considered the role that labor resource constraints may play in this plan.

Section 6 of the Plan describes the 5- and 10-year planning solutions for each sub-region, and Section 7 details the specific 5-year investment summary. Significant Plan-specific expenditures will begin in 2025, ramp up over a 5-year period, and continue at a significant level through 2034. Different job roles will be required at separate times through 2034 to support the Plan investments. For example, in the earlier phase of the planning window, more resources may be needed in the planning, procuring, and engineering functions as designs are developed for infrastructure buildout. Meanwhile, the need for additional construction support will continue through the 2034 period. While construction roles may be shorter duration as they support the initial build out of the network in the first five to ten years of the Plan, there will subsequently be a need for additional job roles to maintain and operate the network, including those in communications and information technologies, computer science, and data analytics.

Complementing the jobs required to build and operate the electric network, there will be additional roles focused on helping customers manage energy use and electrify end uses. The recent Mass

[2] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, July 2023, Page 23, Figure 3. https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment

[3] CECP, Appendix D https://www.mass.gov/doc/appendices-to-the-clean-energy-and-climate-plan-for-2025-and-2030/download

Save Three-Year Energy Efficiency Plan for 2022 – 2024[4] can serve as a model for how programs can engage in workforce development efforts – for example by leveraging relationships with statewide organizations like MassCEC's Workforce Development programs, or efforts by the EE Program Administrators to directly influence the development of the energy efficiency and electrification workforce.

12.3 Workforce Training (with Action Plans) – Building the Workforce Needed to Build and Operate the Grid of the Future

Background

A 2021 NASEO survey[5] shows that the U.S. energy sector has below-average representation of Black, Hispanic, and Latino, and women workers, and high rates of union members with low diversity representation. Specifically, the survey shows that just 8% of energy workers are Black compared to a 12% average across the national workforce. Similarly, Hispanic or Latino individuals comprise 16% of energy workers yet represent 18% of the national workforce. Only 25% of energy workers are women despite comprising 47% of the national workforce. On the other hand, union membership in the energy sector is 11%, while the national average is a mere 6%.

The energy sector in the Commonwealth experiences similar disparities among the diversity of energy workforce. In addition, a recently released study[6] found that Massachusetts has the 6th largest wealth gap[7] by race in the U.S. Addressing these disparities in Massachusetts will require a collective effort across various sectors. The Company is committed to taking action through its comprehensive Workforce Development (WFD) Strategy, which has the potential to change the lives of many, including full-time employees of the Company as well as affiliated vendors or contract partners. This will have a ripple effect on their families, and the communities where they reside.

Strategic workforce development strategy overview

The Company's New England WFD Strategy[8] is a comprehensive, strategic plan to address the Company's workplace skills and diversity gaps while positively impacting the lives of those it touches and the communities it serves. The strategy will position the Company to increase the skills and diversity of its workforce by sourcing talent from all the communities it serves, while creating generational wealth in these same communities. At its core, the WFD Strategy will address gaps in how the Company cultivates diverse talent by employing four strategic pilot programs:

- **Energy Infrastructure Academy** prepares work-ready adults for entry level to mid-level roles within the Company's unionized workforce. The Company has partnered with Franklin Cummings Tech, Training Resources of America, Inc., Community Work Services, and STRIVE Boston to provide professional training for people interested in working in the energy industry. This Academy, which launched in March 2023, holds classes in Boston and

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[4] Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan, 2022 – 2024. https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf

[5] NASEO, 2021. Diversity in the U.S. Energy Workforce: Data Findings to Inform State Energy, Climate, and Workforce Development Policies and Programs. https://www.naseo.org/data/sites/1/documents/publications/Workforce%20Diversity%20Data%20Findings%20MASTER%20Final42.pdf

[6] Boston Globe. Mass. has sixth-highest rate of Income Inequality, September 24, 2016. https://www.bostonglobe.com/metro/2016/09/20/massachusetts-has-highest-rate-income-inequality/MZFDqNcJJh8hJLqqd3zvFL/story.html

[7] https://thisweekinworcester.com/ma-6th-biggest-wealth-gap-race-012522/

[8] National Grid New England Strategic Workforce Development https://www.nationalgridus.com/News/2023/04/National-Grid-Launches-Multi-Pronged-Workforce-Development-and-Scholarship-Program-to-Increase-Diversity-of-its-Massachusetts-Labor-Force-/

Worcester and provides nearly 200 hours of instruction to develop a combination of technical skills, soft skills, three weeks of hands-on job experience with Company employees, networking, and mentorship. This Academy prepares participants for full-time union role opportunities in an earn-while-you-learn on-the-job training. Trainees learn about the Company's electric and gas operations, as well as project planning and construction. Trainees who successfully complete this Academy are encouraged to apply for full-time positions within the Company or a vendor partner and are supported in that effort.

- **Clean Energy Careers Academy** is an 8-week program for college and university students. The Company has partnered with Northeastern University, Franklin Cummings Tech, and UMass-Boston for this Academy. Participating students receive mentorship from current employees and engage with the energy and utilities field, receive professional development opportunities, and create connections that can lead to future internships, co-ops, and full-time employment within the Company. As part of this long-term partnership, the Company announced a $300,000 Clean Energy Scholars Scholarship to support and encourage more students from historically underrepresented communities to pursue and persist in obtaining Engineering and Craft and Trades related degrees and certificates. Each partner institution receives $100,000 in the first year of the partnership, and scholarship funds will continue throughout the duration of the partnership. Students can apply for scholarships through their respective institutions.
- **Clean Energy Tech Academy** is for High School and Vocational Technical (VocTech) students. This Academy enables students to explore energy field careers and learn about career industry opportunities while enabling their professional development. These Tech Academies are being conducted at the Boston Green Academy, Dearborn STEM Academy, and Madison Park Vocational Technical High School, all of which are in Boston, and the Worcester Vocational Technical High School in Worcester. Students who successfully complete the 3- to 5-day program receive a certificate from the Clean Energy Tech Academy and career pathway experiences from mentors at the Company.
- **Clean Energy STEM Academy** is designed for middle school students. The Company mentors and introduces students to the energy industry and provides hands-on activities in STEM education. Boston Green Academy, Dearborn STEM Academy in Roxbury, and Forest Grove Middle School in Worcester are program partners. Students who successfully complete the 3- to 5-day program receive a certificate from the Clean Energy STEM Academy.

Through these Academies, the Company aims to achieve three main goals over the next five years: (1) To implement the 5-year workforce development strategy driven by forecasted workforce planning business needs; (2) Test and validate Company strategy, with a focus on craft and trades; and (3) Engage employee-led groups and our community/education partners and collaborators to ensure their input, lessons learned, best practices, and expertise are continuously incorporated.

These programs are supplemented by talent development supporting pathways, including:

- Clean Energy Scholars Program – The Company offers scholarships to individuals representing underrepresented groups to help defray the cost of obtaining a certificate or undergraduate degree.
- Mentorship Program – Individuals are matched with Company employees or vendor/contract partner employees, who will serve as a support system.
- Internships / Co-ops – The Company offers paid internships and co-ops to help students gain hands-on, real-world business experience and earn while they learn.

- Apprenticeship / Energy Infrastructure Academy – Attract the unemployed and underemployed through outreach and engagement. Offer industry-specific training that allows the Company to hire from a diverse pool of qualified candidates with industry-specific knowledge.
- Company Site Visits – Visit Company facilities and walk in the shoes of the Company's engineers, field employees, and others.
- School Roundtables / Class Projects – Employees engage students in classroom discussions about the energy industry and how the Company is transforming its electricity and gas networks with smarter, cleaner, and more resilient energy solutions towards the vision for a fossil-free future. Collaboration occurs with professors and administrators, offering students opportunities to work on projects that solve real-business issues.
- Other Support – Individuals receive support for resume writing, interviewing, assessments, exams, and navigation through the corporate environment. They are placed in a cohort and introduced to employee resource groups (ERGs) and similar organizations.

NE Clean Energy Line Worker Certificate Program

MassCEC's July 2023 Report, "Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment," found that the Commonwealth will need over 134,000 clean energy jobs by 2030 to meet the Commonwealth's climate targets, growing from approximately 104,000 FTE jobs in 2022.[9] The Company's Clean Energy Academies can support this effort. The clean energy academies place a priority on academics, vocational skills development and on-the-job training opportunities necessary for entry into clean energy jobs at the Company and our vendor partners.

A specific identified area of need is line workers. The electric utility industry is facing a critical shortage of qualified workers, specifically line mechanics and technicians, due to many workers retiring. Yet those in historically underrepresented communities experience barriers accessing programs that provide line worker training (e.g., training cost and transportation). The Company's Strategic WFD team proposes to develop a **Clean Energy Line Worker Certificate** program in response to the demand for overhead (OH) electric line workers throughout the Massachusetts Region. This Certificate program will be an expansion of the Company's Energy Infrastructure Academy for work-ready adults.

To build the Energy Infrastructure Academy Clean Energy Line Worker Certificate program, the Company proposes to partner with two-year academic and training organizations that could include: Bristol Community College, Job Corp; Quinsigamond Community College in Worcester, and Franklin Cummings Tech; PowerCorps Boston; Bunker Hill Community College; and Roxbury Community College in Boston.

This training program would be designed for those who want to enter the workforce immediately following graduation. Graduates of the Energy Infrastructure Academy have been very successful in securing positions with the Company and vendor partners, with more than 30 graduates securing full-time positions to date.

The proposed Clean Energy Line Worker Certificate program would include courses aligned with Electrical Construction and Maintenance requirements. The certificate program would include AC/DC electricity courses, technical math courses, OSHA 10 safety and CPR courses, commercial driver's licenses (CDL) permit test preparation, electrical wiring courses, industry specific electric power courses, and agility training.

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[9] Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment, July 2023. https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment

Clean Energy Re-Entry Program

The Company understands that it can positively impact its communities through infrastructure development. As part of a clean energy transition strategy that is just, fair, and equitable, individuals from within the Company's communities who might not have considered the energy sector as a career choice need to be identified, recruited and trained.

Last year over 2,000 people were released from state prisons. These individuals are known as returning citizens. Returning citizens are considered hidden workers;[10] a group of people who are eager to work and possess—or could develop—skills sought for in the energy sector. According to Accenture's research, companies that hire hidden workers were 36% less likely to face talent and skills shortages compared to companies that do not.

Governor Healey's administration is committed to reducing recidivism and has included over $10M in funding[11] to bolster re-entry services. Leveraging the Company's alignment with the Governor's agenda, the Company proposes developing a Clean Energy Re-Entry Program and partnering with organizations such as STRIVE Boston, PowerCorps Boston, National Urban League, and BlocPower who already work with this population to identify individuals who have 'nonviolent' offenses and would be good candidates.

To be accepted into the Clean Energy Re-Entry Program, individuals would be approximately nine months away from release or completed their incarceration and demonstrate a willingness to work. Through the Clean Energy Re-Entry Program, trainees will receive work readiness and skills training to help prepare them for meaningful employment upon release. The Program's four weeks paid on-site training will allow the participant to gain skills that could lead to full-time employment opportunities in energy efficiency. The Company recommends piloting this Program in Spring 2024 with BlocPower, with an eye to expand the Program upon demonstrating success.

Funding Opportunities

The Company team has identified the funding opportunities shown in Exhibit 12.1 that will help expand and scale the Company's WFD efforts and offset Company investments.

[10] https://www.accenture.com/us-en/insights/consulting/finding-hidden-talent
[11] https://www.wbur.org/news/2023/04/24/massachusetts-prisoner-reentry-classes-funding

Exhibit 12.1: WFD Funding Opportunities

No.	Strategic WFD Initiatives Potential Funding Sources	Description	Amount	Duration	Status
1	(IIJA) Future Grid Project	As described in Section 7.1.2 the Company was selected to receive a competitive federal grant for an innovative smart grid technology project ("Future Grid Project") from the US Department of Energy (DOE) under the IIJA via the Grid Resilience and Innovation Partnerships (GRIP) Program. A portion of this grant will help support the Company's Workforce Development Energy Infrastructure Academy's 12-week training program costs and trainees' stipends for 4 cohorts X 15 students; 60 students / year.	$1.9M	Over 5 years	Awarded December 2023
2	(IIJA) Greener Grid Brayton Project	A collaboration with Bristol Community College National Offshore Wind Institute to develop a training program (curriculum and internships) focused on training line workers to support Offshore Wind industry.	$2M	Over 8 years	Reapplied January 2024; Award decision anticipated June 2024
3	MassCEC Capacity Funding	A collaboration with Training Resources of America, as an industry partner, to build the capacity necessary to scale the Company's Energy Infrastructure Academy trainees in Worcester in skills needed for clean energy field roles.	$150K	1 year	Awarded September 2023
4	MassCEC Clean Energy Intern Program	This Program reimburses Industry Partners up to 90% of clean energy interns' labor costs for up to 12 weeks.	$50K	Annually	Ongoing
5	Commonwealth Corporation	Workforce competitiveness trust fund for workforce development training to meet the skill needs of businesses in high-demand occupations.	$25M	TBD	Applied October 2023; Decision anticipated April 2024
6	Massachusetts Clean Energy Center	This funding is for re-entry pathways including green career training programs to support wind technology, clean homes, and workforce training programs in the clean energy industry.	$30M	TBD	Future Opportunity
7	Summer Jobs Program	This funding is for Summer Jobs Program for At-Risk Youth (Youthworks) to subsidize wages and facilitate career development.	$16.2M	TBD	Future Opportunity
8	Career Technical Institutes	This program is for Career and Vocational Technical Institutes for workforce development training.	$15.4M	TBD	Future Opportunity

12.4 Location economic development impacts

To estimate the economic benefits attributable to the EDCs' respective ESMPs, the EDCs have collaboratively employed the Regional Input-Output Modeling System II (RIMS-II)[12], a tool developed by the United States Department of Commerce – Bureau of Economic Analysis (BEA). This approach leverages a region-specific capital multiplier for Massachusetts, ensuring a tailored evaluation of the economic impact. The EDCs' joint effort in this analysis underscores a commitment to understanding and maximizing the positive economic effects of their investments across the Commonwealth, reinforcing the collaborative approach in driving regional economic development.

The RIMS-II model serves as a state-of-the-art framework to estimate the economic benefits of capital investments, such as building new facilities or upgrading existing infrastructure. The analysis considers the direct and indirect impacts of such an investment. Direct impacts refer to the immediate economic activities associated with the capital investment, such as direct hiring of construction workers, purchasing materials, etc. Indirect impacts consist of the secondary economic effects that occur in other industries because of the direct capital investment, such as increased business for companies supplying construction materials, or transportation and logistics to deliver materials.

In particular, RIMS-II helps assess the direct and indirect "ripple" effects that such investments have on local job creation and overall economic activity. This model quantifies these impacts using "final-demand multipliers" – key indicators that measure how each dollar of capital investment stimulates additional economic activity and job creation across various sectors of the local economy. This model helps depict that the proposed ESMP investments are not only advancing the utility's capabilities and the Commonwealth's climate goals, but also contributing positively to the economic vitality of the Commonwealth.

The economic impact calculation was based on regional economy-wide impacts of the BEA RIMS-II approach and is summarized in the table below for the 5-year, and 10-year Capital Plans. Refer to 7.1 – Investment Summary 5-Year Chart and 7.2 – Investment Summary 10-Year Chart in Section 7 for details on these investments.

Exhibit 12.2: Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology

Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology		
Capital Plan Expenditure	**Total Investments***	**ESMP Investment**
5-Year Capital Plan ($M Nominal, 2025-2029)	$6,829	$2,051
10-Year Capital Plan ($M Nominal, 2025-2034)	$14,586	$4,565
Additional Economic Impact of Investment	**From Total Investments***	**From ESMP Investments**
5-Year Net Economic Benefit ($M Nominal, 2025-2029)	$1,668	$501
10-Year Net Economic Benefit ($M Nominal, 2025-2034)	$3,562	$1,115

[12] "*RIMS II Input-Output Model User Guide*." Bureau of Economic Analysis, https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf

Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology		
Employment Impact of Investment	**From Total Investments***	**From ESMP Investments**
5-Year Employment Impact (# Jobs, 2025-2029)	13,113	3,939
10-Year Employment Impact (# Jobs, 2025-2034)	28,006	8,766

** Total Capital Investments include base spending, active regulatory, and ESMP investments as summarized in Section 7.*

The RIMS-II economic analysis uses the "Type I Final Demand Output Multiplier" to estimate the total economic impact of increased investment on the output of a region. For the ESMP, the Company leveraged the Commonwealth of Massachusetts Type 1 multiplier for the Electric Power Generation, Transmission, and Distribution sector. This multiplier means that every dollar of direct capital investment produces an additional $1.244 of economic activity, including direct and indirect impacts of the investment. Applying the RIMS-II modeling to the total ESMP investments, as outlined in Section 7.1, shows that the Plan will contribute to considerable economic activity for the Commonwealth.

Over the span of 2025 – 2029, these economic benefits (nominal) are estimated at $1,668 million of additional economic activity generated by the Company's total base spend, active regulatory, and ESMP capital expenditures. When considering only the proposed ESMP capital investments, the additional economic activity calculated is $501 million. Over the 10-year period of 2025 – 2034, the corresponding results are approximately $3,562 million from the total base spend, active regulatory, and ESMP capital investments and nearly $1,115 million from proposed ESMP investment alone.

Additionally, the capital investments are expected to foster job creation across the Commonwealth and through local industries. This includes direct jobs such as construction workers, and indirect jobs[13] such as local suppliers providing materials. Similar to the economic impact analysis, the RIMS-II model applies an indirect job multiplier of 1.920 for every additional $1 million of output delivered to final demand.[14]

The RIMS-II model estimates the total investments, consisting of base spend, active regulatory, and ESMP investments will generate over 13,113 jobs[15] from 2025 through 2029, and more than 28,006 jobs during the extended period of 2025 through 2034. When considering solely the proposed ESMP capital investment during the same periods, job creation is expected to be 3,939 and 8,766, respectively. The estimated direct and indirect impacts of these calculations reflect a broad perspective of the impact of the direct economic activity and the rounds of spending in the economy associated with these investments.

Given the infrastructure investments across the six sub-regions and across the service territory, direct economic impacts from the construction of the proposed infrastructure can be expected to occur broadly. Significant expenditures will go towards construction, electrical equipment manufacturers and suppliers, and other supporting industries that provide the materials, skilled labor, and supporting services to enable these investments. Beyond the direct impacts of the construction of electrical infrastructure, the buildout of the network will further enable economic growth in each sub-region by providing sufficient capacity to meet the forecast demand.

Some economic impacts occurring directly from ESMP infrastructure investments will be highly local

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[13] Direct jobs are those created by the investment itself, while indirect jobs are in the businesses that support the investment.
[14] https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf
[15] Includes both full-time and part-time positions and are not equivalent to full-time equivalent (FTE) positions

while others will occur in a more distributed fashion. For example, direct construction expenditures will typically impact the region where the construction activities occur if local labor is sourced, and some materials are purchased locally. Those wages paid to local personnel will then pass through to other economic sectors, both locally and more broadly. Increased construction activities and infrastructure may have positive revenue impacts for communities, as incremental property tax payments are made to local municipalities that host new infrastructure projects.

Other expenditures associated with infrastructure investments, such as materials purchases, may have different locational impacts. Some portion of those expenditures will be made in the local, state, or regional economy depending on supply chains and sourcing opportunities. Other materials and supplies (such as transformers) would have a more distributed impact, as sourcing may occur on a national or international scale.

Ongoing customer program investments (discussed in Section 6.1) are typically broad-based offerings that are accessible to customers across the service territory and the Commonwealth. The economic impact of these initiatives will therefore be similarly broad-based and rely on a variety of supporting businesses and local employment, including program implementation, support personnel, and materials suppliers. For example, the Mass Save EE and electrification programs support a broad workforce that includes energy auditors, HVAC installers, program operation support, and weatherization contractors. The clean energy workforce will continue to grow in importance with continued investment through the ESMP and will be supported by the Company's strategic efforts detailed in Section 12.3.

12.5 Health Benefits

The ESMP investments and ongoing customer programs will enable a variety of environmental and climate benefits that will lead to improved health benefits and outcomes. These investments will expand and reinforce the electric network and will promote electrification options that will offset fossil fuel consumption. These will provide health benefits for all customers, but especially EJCs that are most impacted by negative health effects from poor air quality.[16] [17] Benefits will be realized at the local and state level through emissions reductions, improvements in building air quality, and positive climate impacts that will occur within and beyond the Commonwealth's borders.

Capacity expansion and grid modernization will enable increased penetration of renewable energy, which will ultimately lead to reductions in GHG emissions and air pollutants. Higher integration of renewables and DERs will reduce dependence on fossil fuel generation, decreasing the release of CO_2 and methane (CH_4), which contribute to climate change. This shift also mitigates the emission of criteria air pollutants, such as sulfur oxides (SO_X), nitrogen oxides (NO_X), and fine particulate matter ($PM_{2.5}$) that have well documented impacts on respiratory and cardiac disease.[18] [19] Reducing air pollutants decreases the risk of asthma, lung cancer, and heart attacks, thereby improving overall public health. While improved ambient outdoor air quality has positive health impacts for all, it can be especially beneficial for low- and moderate-income (LMI), environmental justice (EJ), and other vulnerable communities that may face either high concentrations of ambient air pollutants or greater sensitivity to their impacts. Poor air quality can disproportionately impact sensitive populations, such as those with medical conditions like respiratory problems, children, the elderly, and pregnant women.

[16] https://www.epa.gov/air-research/research-health-effects-air-pollution

[17] https://www.lung.org/research/sota/health-risks

[18] https://www.niehs.nih.gov/health/topics/agents/air-pollution/index.cfm

[19] https://www.epa.gov/system/files/documents/2023-01/Estimating%20PM2.5-%20and%20Ozone-Attributable%20Health%20Benefits%20TSD_0.pdf

As part of the net benefits assessment discussed in Section 7.1.4, the Company has quantified the estimated NO_X and $PM_{2.5}$ emissions reductions enabled by the Company's Future Grid Plan. Exhibit 12.3 below summarizes the results for these estimated emissions reduction benefits.

Exhibit 12.3 Projected Emission Reductions Enabled by the Future Grid Plan

Air Pollutant	Total Reduction
CO2 Reduced	31.3M MT
NOx Reduced	7,462 MT
PM 2.5 Reduced	162.7 MT

In addition to ambient outdoor air quality benefits, the increased adoption of EE and EH can lead to improved indoor air quality. This is especially beneficial for EJCs that may face higher baseline indoor pollution levels. Non-energy impacts from EE and electrification measures such as health benefits, thermal comfort, and noise reduction, are well-studied and documented within the triennial energy efficiency plans implemented by the Company and the other Mass Save Program Administrators.[20]

Electrification of transport can also reduce pollution from internal combustion engine vehicles, and further contribute to ambient air quality improvements and health benefits. These emissions impacts can also be highly localized and can have differential impacts depending on the location and intensity of the emissions. In more densely populated urban areas, higher vehicle density can lead to higher emissions concentrations and air pollution impacts, which can disproportionately impact EJCs. Increased adoption of EVs enabled by additional system capacity and programmatic offerings can reduce local air pollutants that have adverse health consequences, including particulates and ozone.[21] [22]

Reducing GHG emissions decreases the public's risk of exposure to health-related impacts of climate change.[23] Climate change increases the likelihood of extreme weather events and heat waves that can exacerbate pre-existing health conditions, leading to injuries, illness, and premature deaths. Rising temperatures can also spread diseases caused by insects and viruses and increase the likelihood of food and water-borne disease. Climate change may limit crop production or foster increased pest activity, leading to wider food insecurity. Heat and natural disasters can also lead to trauma and higher levels of anxiety and depression, potentially worsening the mental health crisis. The Company has outlined a framework for assessing and prioritizing resiliency in Section 10 which seeks to mitigate climate change, reducing the possibility of these public health outcomes.

The Future Grid Plan will deliver significant benefits across the Commonwealth that will support the transition to a clean energy future. The Plan is poised to deliver significant economic impacts as investments in the distribution system enable all to take advantage of opportunities to participate in the transition towards higher penetration of electrified transportation, heating, and renewable energy generation. The Company is poised to play a key role in this transition and support the development of the clean energy workforce that will be required to meet this opportunity. Through these efforts the Commonwealth will move forwards towards its climate goals and improve public health outcomes by reducing the harmful effects of present energy consumption.

[20] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf
[21] https://www.lung.org/clean-air/electric-vehicle-report/driving-to-clean-air
[22] https://www.epa.gov/mobile-source-pollution/environmental-justice-and-transportation
[23] https://www.niehs.nih.gov/research/programs/climatechange/health_impacts/asthma/index.cfm

Section 13
Conclusion

This section describes next steps for the Future Grid Plan, including a discussion of reporting and metrics.

Key Take-Aways

- In the period following the submission of the Company's Future Grid Plan to the GMAC, the Company will support all aspects of the GMAC review process, including provision of any requested clarification or background information to inform GMAC of findings and recommendations
- The Company proposes creating a new Community Engagement Stakeholder Advisory Group to develop a Community Engagement Framework that can be applied to Future Grid infrastructure projects before they are brought before the Energy Facilities Siting Board.
- The Company's Future Grid Plan with the Department reflects GMAC and other stakeholder feedback. The EDCs propose to continue to work with interested stakeholders to address metrics relating to the EDCs' respective ESMP investments in a future phase of the ESMP dockets.
- So that the Company can demonstrate the delivery of the investments included within the Future Grid and associated benefits, the EDCs propose infrastructure and stakeholder metrics which will include both statewide as well as company-specific metrics tied to each EDC's ESMP goals.

13.0 Conclusion

13.1 Next Steps

A smarter, stronger, and cleaner energy future for the Commonwealth rests upon developing comprehensive, inclusive, and flexible plans that upgrade today's electric grid rapidly and at significant scale. The Company's Future Grid Plan details a comprehensive plan for the next five to ten years, laying out steps needed to meet the Commonwealth's 2050 decarbonization targets. This Plan describes proposed investments for the next five years (2025 through 2029), and a second ESMP will be submitted with proposed investments for the second five years (2030 through 2034). In the interim, the Company will solicit stakeholder feedback to ensure transparency and accommodate recommendations based on GMAC and stakeholder feedback prior to the submission of the Company's next ESMP.

The Company has been committed to a robust and proactive public engagement process throughout the development of the Future Grid Plan. The Company worked with the other EDCs to conceptually develop a new Community Engagement Stakeholder Advisory Group (CESAG), which the EDCs would like to be co-led by a community-based organization, to ensure stakeholders are engaged throughout the ESMP planning process. The CESAG will establish a Community Engagement Framework to be applied to proposed ESMP Investment projects before such projects are brought before the Department in a subsequent ESMP. Along with this Framework, the Company will develop a mechanism to collect and organize stakeholder feedback to be considered in the distribution system planning process where feasible. The stakeholder engagement approach is described in Section 3. Additionally, the Company will submit two reports per year to the Department, which will include a set of agreed upon metrics. These reporting requirements and metrics are discussed in the following sub-sections.

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 to 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 on implementation, stakeholder engagement, and benefit realization. As described in Section 13.3, the EDCs also support adoption of common performance metrics. Results according to these metrics would be included in ESMP reports.

The EDCs recommend biannual reporting as follows:

Report Due Date	Reporting Period	Description
April 1	July through December of the prior year	Provide comprehensive report on ESMP progress, including results relative to performance metrics (replacing the current Grid Modernization Plan Annual Report)
October 1	January through June of the current year	Provide a higher-level interim review of year-to-date progress.

These timelines best align with the EDCs' many existing dockets and annual reporting timelines. 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 biannual reporting.

In the period following the submission of the Company's Future Grid Plan to the GMAC, the Company will support all aspects of the GMAC review process, including provision of any requested clarification or background information to inform GMAC of findings and recommendations.

13.3 Reporting and Metrics Requirements with Common EDC Table

The EDCs are performance-focused and aspire to provide safe, reliable, and cost-effective service to all customers every 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 fully support the creation of metrics to measure progress and performance of the ESMP investments in relation to the ESMP objectives. The Company proposes working with interested stakeholders to develop metrics relating to the EDCs' respective ESMP investments in a future phase of the ESMP dockets.

There are several existing frameworks and reporting constructs that should initially be considered and leveraged for any suitable and transferable metrics. The EDCs have committed or pending metrics across several dockets in the Department. The following investment categories have existing or pending metrics 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 optimal 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 in the ESMP reporting template as described above, the EDCs have worked to develop new ESMP-specific metrics designed to ensure full transparency with respect to all ESMP expected outcomes.

The EDCs propose infrastructure and stakeholder metrics which will include both statewide as well as company-specific metrics tied to each EDC's ESMP goals. In developing the metrics associated with each goal and outcome as this proceeding moves forward, it was imperative that such metrics follow the following principles:

- Be susceptible to objective and transparent measurement;
- Have an established baseline against which performance can be measured;
- Measure "performance" that is within the EDC's control; and
- 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 the Commonwealth's policy goals;
- **Customer Value** – creates/demonstrates value for customers, balancing the burden across the Company's 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 developed an initial view of both the statewide and company-specific metrics, which the EDCs provided to the GMAC in October 2023. The purpose of these ESMP metrics is to record and report information, internally to the Department, to GMAC, and to the Telecommunications, Utilities, and Energy working group.

Infrastructure metrics track a Company's deployment and investments of ESMP projects and technologies. The EDCs are proposing the following infrastructure metrics:

- Using commercially reasonable efforts, the achievement dates of ready for load (RFL) for major ESMP infrastructure projects which will be measured from the time the EDC receives: (1) a final, non-appealable order from the Department approving a cost recovery mechanism applicable to the project; and (2) all required permits and approvals for such projects through final, non-appealable state or federal orders and local permits.

- The percentage of customers covered by/benefiting from incremental resiliency investments outlined in the EDC's ESMP.

- The increase in: (a) DER hosting capacity, and (b) load serving capacity by substation demonstrated by an increase in transformer rating installed. This metric will additionally include reporting information specific to environmental justice communities (EJCs), stating what percentage of benefits is located in an EJC. This metric will be measured from the time the EDC receives: (1) a final non-appealable order from the Department approving a cost recovery mechanism applicable to the substation project, and (2) for specific projects at the time when all required permits and approvals for such projects are received, including through final, non-appealable state or federal orders and local permitting processes.

- A measure of the greenhouse gas reduction impact of investments enabled in alignment with statewide greenhouse gas reduction targets. This metric will be measured from the time the EDC receives: (1) a final non-appealable order from the Department approving a cost recovery mechanism applicable to the investment, and (2) for specific projects at the time when all required permits and approvals for such investments are received, including through final, non-appealable state or federal orders and local permitting processes. The EDCs have contracted with an expert consultant to analyze the net benefits of each EDC's incremental investments, which will include greenhouse gas reduction analyses. The EDCs welcome input from the GMAC regarding recommended approaches to analyzing and measuring greenhouse gas reduction benefits.

- For the EDC's distributed energy resources management system (DERMS), (a) the number of participating sites, (b) the amount (kW) of non-company owned dispatchable assets that the utility can control, and (c) number of instances sites are dispatched. The EDCs note that this metric is already under consideration by the Department as a proposal through 2025 in D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82. The EDCs propose that the metric would continue for incremental DERMS investments in 2026 and beyond.

Stakeholder metrics track a company's outreach and community involvement for both the ESMP filing and specific ESMP infrastructure projects. The EDCs are proposing the following stakeholder metrics:

- The number of outreach and involvement meetings about the respective EDC's ESMP filing with stakeholders, including EJCs, municipal leaders, community-based organizations and customers (i.e., residential, commercial and industrial, as well as DER customers).
- The number of outreach and involvement meetings about specific ESMP infrastructure projects with stakeholders, including EJCs, municipal leaders, community-based organizations, and customers (i.e., residential, commercial and industrial, as well as DER customers).
- The number and category of requests made as part of stakeholder feedback on specific ESMP infrastructure projects, classified into visual mitigation, access accommodations, work hours, right-of-way maintenance, informational accommodations, engineering accommodations, and damage prevention, as well as the EDC's response to these requests classified as under consideration, implemented, not accepted with reason, and other.

The EDCs will also 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 propose to work with interested stakeholders to address metrics relating to the EDCs' respective ESMP investments in a future phase of the ESMP dockets.

13.4 Process to Report to DPU and Joint Committee on Telecommunications, Utilities, and Energy

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Council throughout the ESMP plan period with discussion and updates supported through the biannual reporting. In addition to the GMAC, the biannual reports will be provided to the Telecommunications, Utilities, and Energy working group. As described in 13.2, the EDCs proposed a timeframe for the biannual reporting to be April 1 for the previous year January - December timeframe and October 1 for the current year January - June timeframe update. These timelines best align with many existing dockets and annual reporting timelines which will be leveraged and incorporated into the Company's overall biannual reporting efforts.

Section 14

Appendix

This section includes a ESMP Stakeholder Engagement Table, Exhibits 1-5 and glossary.

Exhibit 1: ESMP Glossary

GLOSSARY

Term	Definition
Advanced Distribution Management System (ADMS)	ADMS is a software platform that enables real-time visibility and control of the physical infrastructure making up the distribution system. The system will provide system operators with an as-operated electrical model of the entire distribution system and support advanced applications for fault location, automated restoration, and voltage management. See section 6.3.1.1. for more details.
Advanced Metering Infrastructure (AMI)	AMI refers to a modern system of utility meters, sometimes referred to as "smart meters". AMI uses advanced technology, such as two-way digital communication, to collect and transmit data. A key added value of AMI is the ability to remotely collect data, control the meter, or check the service status during an outage event.
Ancillary Structures	Ancillary structures encompass structures which are an integral part of the operation of any transmission line. The term “ancillary structure” has been interpreted by the EFSB to include substations or switching station additions.
Automated Meter Reading (AMR)	AMR is the type of meter currently used by National Grid. It is a drive-by system to collect a single volumetric usage number once a month. AMR is going to be replaced with AMI under the current plan.
Behind the Meter (BTM)	BTM refers to DER installations located on the customer side of the electric meter. It typically involves rooftop solar panels, residential energy storage systems, demand response, and other DERs that are installed at individual homes or businesses.
Blue-sky	Days without storms.
Breaker (circuit breaker)	A circuit breaker is a device designed to provide protection to the circuit during an abnormal condition. The breaker automatically breaks current when it detects fault conditions such as overcurrent or short circuit.
Bridge to Wires	For a “Bridge to Wires” NWA, the Company is faced with an imminent need for a capital project, but that capital project cannot feasibly be delivered in time to address the need. In this case, the “Bridge to Wires” solutions can be deployed quickly to reduce peak demand or increase peak supply to help manage reliability during that gap period when overloads on the network may be expected during peak hours. See Section 6.4.2.5.
Bus Work	In a substation, bus work is a group of rigid conductors typically made of aluminum or an alloy that serve as a common connection between the other components of the substation.
Capacity	The rated and continuous load-carrying ability, expressed in megawatts or megavolt-amperes, of generation, transmission, or other electrical equipment.
Capital Investment Project (CIP)	CIPs are projects aimed at facilitating the deployment and interconnection of distributed generation as outlined by D.P.U. order 20-75B of November 24, 2021. CIPs allocate costs between project beneficiaries, including current and future DG customers and ratepayers.
Cascade	Cascade is a software application that serves as the Company’s asset repository and system of record for substation equipment.

Term	Definition
Clean Energy and Climate Plan (CECP)	The 2022 “Clean Energy and Climate Plan for 2025 and 2030 and “Clean Energy and Climate Plan for 2050” aim to achieve emissions reduction for the Commonwealth set by the Climate Act (see below). The Secretary of EEA has adopted the interim 2025 statewide greenhouse gas emissions limit of 33 percent below 1990 level and the interim 2030 statewide greenhouse gas emissions limit of 50 percent below 1990 level. Clean Energy and Climate Plan for 2025 and 2030: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 Clean Energy and Climate Plan for 2050: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050#development-of-the-clean-energy-and-climate-plan-for-2050-
Climate Act (or the Act)	The 2021 “Act Creating a Next-Generation Roadmap For Massachusetts Climate Policy” set the target of net zero statewide greenhouse gas emissions by 2050. In addition, the Act defines Environmental Justice Populations and “environmental burden” in state statutes.
Community Benefits Agreement	The purpose of Community Benefits Agreements is to ensure that communities that host clean energy infrastructures directly benefit from those infrastructures. See Section 3.5.
Community Engagement Stakeholder Advisory Group (CESAG)	Proposed by the EDCs, the goal of the CESAG is to develop a Community Engagement Framework that can be integrated when implementing new clean energy infrastructure projects. See section 3.5. for more details.
Community Solar	Community Solar refers currently to solar generation facilities that provide electricity or bill credits to multiple utility customers. See section 6.1.7.2.
Customer Average Interruption Duration Index (CAIDI)	Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. CAIDI is typically measured in minutes.
CYME	CYME refers to a simulation tool used to analyze distribution feeders, including basic load allocation, load flow and fault current analysis.
Demand Response (DR)	Demand response (DR) refers to balancing the demand on power grids by encouraging customers to shift or curtail electricity demand to times when electricity is more plentiful or other demand is lower, typically through prices or monetary incentives. Examples of current Company programs include traditional load curtailment, pre-cooling with smart thermostats, shifting energy usage with energy storage, and shifting EV charging to off-peak periods.
Distributed Energy Resource (DER)	DERs include energy efficiency, demand response, solar PV (distributed part), energy storage (distributed part), and electrification load from EV and heat pumps.
Distributed Energy Resource Management System (DERMS)	Control room tool to manage, monitor, and dispatch DER based on real time system conditions. DERMS is a foundational platform capability intended to increase the efficiency and effectiveness of DER integration and to enable the use of DER as a grid asset.
Distributed Generation (DG)	Solar PV and energy storage systems that is connected to the distribution system and contributes to reduced demand on the system.

Term	Definition
Distribution	The delivery of electricity to end users via low-voltage electric power lines.
Electric Power System (EPS)	The EPS refers to the network of components and systems designed to generate, transmit, distribute, and regulate electrical power to end-use customers. See section 4.1.1 for more detailed description and graphic depiction of the EPS. This ESMP is focused on the distribution system segment of the EPS.
Energy Benefits	Based on current state law, Energy Benefits means access to funding, training, renewable or alternative energy, energy efficiency, or other beneficial resources disbursed by EEA, its agencies and its offices.
Energy Efficiency (EE)	EE represents programs that have created a permanent, non-dispatchable load reduction through improvement to building systems, structures, or operations.
Energy Storage System (ESS)	ESS includes any technology that can store energy for any amount of time and discharging that energy as electric power. ESS can include chemical storage systems such as lithium-ion systems or other modes of storage, such as pumped hydro.
Enterprise Energy Control System (eECS)	The Company's combined transmission and distribution SCADA system. eECS provides system operators with visibility and control of remote substation and distribution line devices with communications capability.
Environmental Benefits	Based on current state law, Environmental Benefits means the access to clean natural resources, including air, water resources, open space, constructed playgrounds and other outdoor recreational facilities and venues, clean renewable energy course, environmental enforcement, training and funding disbursed or administered by EEA.
Environmental Justice (EJ)	From current state law, Environmental Justice is based on the principle that all people have a right to be protected from environmental hazards and to live in and enjoy a clean and healthful environment regardless of race, color, national origin, income, or English language proficiency. Environmental justice is the equal protection and meaningful involvement of all people and communities with respect to the development, implementation, and enforcement of energy, climate change, and environmental laws, regulations, and policies and the equitable distribution of energy and environmental benefits and burdens.
Environmental Justice Community (EJC)	See Environmental Justice Population.
Environmental Justice Population	Based on current state law, an Environmental Justice Population is a neighborhood that meets one or more of the following criteria: (i) the annual median household income is not more than 65% of the statewide annual median household income; (ii) minorities comprise 40% or more of the population; (iii) 25% or more of households lack English language proficiency; or (iv) minorities comprise 25% or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150% of the statewide annual median household income.

Term	Definition
Equity	Equity means engaging all stakeholders – including our customers and communities with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts, and justice disparities. We define equity using three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Framework. These include: ○ **Procedural equity,** which focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation. ○ **Distributional equity,** which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition. ○ **Structural equity,** which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities. See section 3.2.
Feeder	Feeders are electrical circuits emanating from a substation that supply areas at distribution level voltages. This term is used interchangeably with "circuits" at the distribution level.
FERC 2222	The Federal Energy Regulatory Commission (FERC) issued Order No. 2222 in 2020, with updates in 2021. The main goal of Order No. 2222 is to better enable distributed energy resources (DERs) to participate in the electricity markets run by regional grid operators.
Flexible Interconnections	Flexible Interconnections allow DER to interconnect to the distribution system with agreed upon operating constraints that reduce the need for system modifications. See 6.3.2.1.
Flexible Services	See Grid Services Solutions.
Forward Capacity Market (FCM)	The FCM is a locational capacity market managed by ISO-NE. In this market, ISO-NE projects the needs of the power system three years in advance and then holds an annual auction to purchase power resources to satisfy the region's future needs.
Front of the Meter (FTM)	Front of the Meter, usually refers to activities, technologies, or systems that are located on the utility side of the electricity meter. For this ESMP, it typically refers to utility-scale ESS.
Generation	The production of electric energy.
Geographic Information System (GIS)	The GIS system is the as-built asset repository which is the primary source model of the distribution system. The GIS asset and connectivity model serves as the source system for real time operations, and system planning models.
Grid Services Solutions	For this ESMP, grid services solutions refer to DERs (customer-owned BTM and third-party FTM) providing services to the grid, such as addressing distribution system capacity constraints, providing reliability, optimizing voltage levels, or deferring / avoiding network investments. See section 6.3.2.1.

Term	Definition
Headroom	Headroom refers to the margin of available capacity at a specific equipment to accommodate additional load without causing violations of equipment specifications.
Heat Pump (Air Source ASHP) or (Ground Source GSHP)	A heat pump is a device capable of heating and cooling a building. During the heating mode, a heat pump extracts heat from an external source (air or ground) and transfers it into the home. In the cooling mode, the process is reversed, and heat is taken from indoor air and expelled outside.
Hosting Capacity	Hosting capacity is the estimated maximum amount of energy from a distributed resource (such as solar panels) that can be accommodated on the distribution system at a given location. This capacity is under existing grid conditions and operations without requiring significant infrastructure upgrades. This capacity takes into consideration safety, power quality, reliability, or other operational criteria.
Interconnection	The connection of DERs to the power grid that ensures safe operations in all grid conditions.
Inverter	An inverter is a device that converts direct current (DC) electricity, which is what a solar panel generates or energy storage system discharges, to alternating current (AC) electricity, which the electrical grid uses to serve load.
K-Bar Adjustment	K-Bar adjustment is a revenue indexing mechanism as part of the Performance Based-Revenue Adjustment mechanism pursuant to section 1.07, as approved in D.P.U. 22-22.
Load	The demand for electricity; electricity consumption; the amount of electric power delivered to any specified point on a system, accounting for the requirements of the customer's electrical equipment.
Meaningful Involvement	Based on current state law, Meaningful Involvement means that all neighborhoods have the right and opportunity to participate in energy, climate change, and environmental decision-making including needs assessment, planning, implementation, compliance and enforcement, and evaluation, and neighborhoods are enabled and administratively assisted to participate fully through education and training, and are given transparency/accountability by government with regard to community input, and encouraged to develop environmental, energy, and climate change stewardship.
Non-Traditional Solution	Alternative approaches to meeting system needs other than traditional system upgrade solutions. These solutions can be customer-owned, third party-owned, or Company owned. Examples include resources such as Energy Storage (ESS), Solar PV, localized Demand Response (DR), Electric Vehicle (EV) managed charging, localized Energy Efficiency (EE) measures, or new flexible interconnection technologies. Section 6.4.2.5.
Non-Wires Alternatives (NWA)	The use of a non-traditional solution to a specific electric network constraint that defers or removes the need to construct or upgrade specific components, or reduces the operational risk related to a specific network constraint, on the distribution and/or transmission system.
Outage Management System (OMS)	The OMS is a detailed network model of the distribution system based on National Grid's GIS. By combining the locations of outage calls from customers, a rules engine is used to predict the locations of outages. OMS data is also used to provide customers with detailed information regarding their outage.
Peak Load	Peak load refers to the highest electricity demand experienced by the grid during a specific period.

Term	Definition
Peak Shaving	Peak shaving refers to a strategy to reduce or "shave" the peak electricity demand during periods of highest usage.
Performance-Based Rate (PBR)	Ratemaking procedure as outlined by order D.P.U. 18-150 of September 30, 2019
Recloser	Reclosers are pole-mounted distribution line equipment which automatically respond to faults by opening to isolate the sections of circuits that are damaged.
Reliability	The assurance that electric power is available even under adverse conditions, such as storms or outages of generation or transmission lines. Reliability has traditionally focused on upholding performance according to regulatory reporting criteria, which excludes the impacts from major events which cause outages that are statistically outside the norm for the system.
Resiliency	**Resiliency** can broadly be defined as the ability of the distribution system to withstand and recover from disturbances, including major events.
Spot Load	Spot Loads represent large (> 500kW or >1 MW depending on system) new load additions which can come from new buildings, or redevelopment of existing sites. These spot loads can include residential developments, C&I, large standalone storage systems, fleet charging operations, and more. See Section 5.1.4.
STORMS	STORMS is the work and asset management software application in use for the distribution system.
Substation	For the purposes of this ESMP, a substation steps down transmission level voltages (typically 69kV and above) to Distribution level voltages (typically below 69kV). The Company also operates distribution to distribution substations that step a distribution-class voltage (35, 23, or 13 kV) to a lower distribution class voltage (13 or 4 kV). See section 4.1.3 for an overview of bulk distribution substations.
Supervisory Control and Data Acquisition (SCADA)	SCADA is the system used for visibility and control of the grid. See 4.7.1.
System Average Interruption Duration Index (SAIDI)	The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period, typically a year. It is commonly measured in minutes or hours of interruption.
System Average Interruption Frequency Index (SAIFI)	SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period of time, typically a year.
Time-Varying Rates (TVR)	TVR is a method to manage demand by implementing varying electricity prices at different times of day.
Transformer	A transformer is a device that steps down or steps up the level of voltage.
Transmission	The transporting of electricity through high-voltage lines typically over long distances.
TripSaver	Specific commercial name of a single-phase recloser.

Term	Definition
Virtual Power Plant (VPP)	A virtual power plant is an aggregation of DERs that can balance electrical demand and supply and provide utility scale and utility-grade services like a traditional power plant. VPPs can include energy efficiency, demand response, energy storage, EV managed charging, solar, and other distributed technologies located at residential, commercial, and front-of-the meter customer premises
Volt Var Optimization (VVO)	Volt/VAR Optimization is a technology designed to manage voltage levels and reactive power flow to optimize the efficiency of the distribution grid. See section 6.3.1.5. for more details.

Acronyms	
ABM	Agent-Based Model
ABR	Automatic Bus Restoral
AC	Alternating-Current
ACC II	California Advanced Clean Cars II Rule
ACEEE	American Council for an Energy-Efficient Economy
ACOE	Army Corps of Engineers
ACT	California's Advanced Clean Trucks Rule
ADMS	Advanced Distribution Management System
ADR	Active Demand Response
ADR	Active Demand Response
AESC	Association of Executive Search and Leadership Consultants
AF	Alternate Fuel
AGO	Massachusetts Office of the General Attorney
AI	Artificial Intelligence
AIS	Air Insulated Substation
ALF	Advanced Load Flow
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AOBC	Alternative On-Bill Credits
ARR	Annual Reliability Report
ASAP	Affordable Solar Access Program
ASHP	Air-Sourced Heat Pump
AWC	Eversource's Area Work Center
BART	Bayesian Additive Regression Trees
BAU	Business As Usual
BCA	Benefit Cost Analysis
BCR	Benefit Cost Ratio
BDEW	Bundesverband der Energie und Wasserwirtschaft (German Association of Energy and Water Industries)
BEA	Bureau of Economic Analysis
BERDO	Building Emissions Reduction and Disclosure Ordinance
BESS	Battery Energy Storage System
BEUDO	Building Energy Use Disclosure Ordinance
BEV	Battery-Powered Electric Vehicle
BFE	Base Flood Elevation
BIL	Bipartisan Infrastructure Law (also refers as Infrastructure Investment and Jobs Act - IIJA)
BIPOC	Black, Indigenous and People of Color
BMPs	Best Management Practices
BT	Boosted Tree
BTM	Behind the Meter

C	Celsius
C&I	Commercial and Industrial
CA	California
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CBO	Community Based Organization
CECP	Massachusetts Clean Energy and Climate Plan for 2025
CEISP	Commission on Clean Energy Infrastructure Siting and Permitting
CEPS	Competitive Electric Power Supplier
CESAG	Community Engagement Stakeholder Group
CHP	Combined Heat and Power
CI	Customer Interrupted
CIP	Capital Investment Project
CLC	Cape Light Compact
CMI	Customer Minutes Interruption
CO	Carbon Monoxide
CO2	Carbon Dioxide
COP	Coefficient of Performance
CVR	Conservation Voltage Reduction
D.P.U.	Massachusetts Department of Public Utilities
DAC	Disadvantaged Communities - as defined by the U.S. Department of Energy
DC	Direct-Current
DCFC	Direct-Courant Fast Charger
DCR	Massachusetts Department of Conservation and Recreation
DE&I	Diversity, Equity and Inclusion
Department	Massachusetts Department of Public Utilities
DER	Distribution Energy Resources
DERMS	Distribution Energy Resources Management System
DERPG	Eversource Distributed Energy Resource Planning Guide
DG	Distributed Generation
DMS	Distribution Management System
DNP	Distributed Network Protocol
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DR	Demand Response
DRWG	Distribution Reliability Working Group
DSO	Distribution System Operator
DSPG	Eversource Distribution System Planning Guide
DT	Decision Tree
DTT	Direct Transfer Trip
D-VAR	Dynamic Volt-Amp Reactive

ECSAP	Eversource Community Solar Access Program
EDC	Electric Distribution Company
EE	Energy Efficiency
EEA	Massachusetts Executive Office of Energy and Environmental Affairs
eECS	Enterprise Energy Control System
EEI	Edison Electric Institute
EFSB	Energy Facilities Siting Board
EJC	Environmental Justice Community
EMA	Eastern Massachusetts Area
EMT	Electromagnetic Transient
ENS	Ensemble Model (p 179 - should be in a FN)
EOEEA	p 198, should be replaced by EEA
EPA	U.S. Environmental Protection Agency
EPS	Electric Power System
EPUT	Electric Power Utility Technology
ESMP	Electric Sector Modernization Plan
ESRI	Environmental System Research Institute
ETR	Estimated Time of Restoration
ETT/ETR	page 504
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
EWG	Grid Modernization Advisory Council Equity Working Group
F	Fahrenheit
FAN	Field Area Network
FCEV	Fuel Cell Electric Vehicle
FCM	ISO-NEs Forward Capacity Market
FEMA	Federal Emergency Management Agency
FERC	U.S. Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
FIRM	Flood Insurance Rate Map
FOA	Funding Opportunity Announcement
FTE	Full Time Equivalent
FTM	Front of the Meter (usually solar or battery)
GCA	2008 Green Community Act
GCA	2008 Massachusetts Green Community Act
GCEP	Greater Cambridge Energy Program
GDO	United States Department of Energy Grid Deployment Office
GHG	Greenhouse Gas
GHz	Gigahertz
GIS	Geographic Information System
GMAC	Grid Modernization Advisory Council

GMP	Gross Metropolitan Product
GMP	Grid Modernization Plan
GPS	Global Positioning System
GRIP	U.S. Department of Energy - Grid Resiliency and Innovation Partnership
GSHP	Ground-Sourced Heat Pump
GT	Gas Turbine
GVWR	Gross Vehicle Weight Rating
GW	Gigawatt
HC	Hosting Capacity
HDV	Heavy Duty Vehicle
HEV	Hybrid Electric Vehicle
HILP	High Impact Low Probability
HVAC	Heating Ventilation and Air Conditioning
IBEW	International Brotherhood of Electrical Workers
ICE	Internal Combustion Engine
IEEE	Institute of Electrical and Electronics Engineers
IEP	Integrated Energy Planning
IIJA	Infrastructure Investment and Jobs Act
IoT	Internet of Things
IP	Internet Protocol
IRR	Internal Rate of Return
ISD	In-Service Dates
ISO	International Organization for Standardization
ISO-NE	Independent System Operator - New England
IT	Information Technology
ITC	Investment Tax Credit
IVR	Interactive Voice Response
kV	Kilovolt
kW	Kilowatt
kWH	Kilowatt Hour
L1	Level 1 Electric Vehicle Charger
L2	Level 2 Electric Vehicle Charger
LAI	Leaf Area Index
LCC	Load Carrying Capacity
LDC	Local Distribution Company (gas)
LDEV	Light Duty Electric Vehicle
LF	Load Factor
LI	Low-Income
LMI	Low to Moderate Income
LOCA	Localized Construction Analogue
LRP	Eversource's Long-Range Plan

LTC	Load-Tap-Change
LTE	Long-Term Emergency
MA	Massachusetts
MA EEAC	Massachusetts Energy Efficiency Advisory Council
MassCEC	Massachusetts Clean Energy Center
MassDEP	Massachusetts Department of Environmental Protection
MassDOT	Massachusetts Department of Transportation
MassGIS	Massachusetts Bureau of Geographic Information
MBTA	Massachusetts Bay Transit Authority
MHEV	Medium and Heavy Duty Electric Vehicles
MDMS	Meter Data Management System
MDV	Medium Duty Vehicle
MEPA	Massachusetts Environmental Policy Act
MHC	Massachusetts Historical Commission
MIT	Massachusetts Institute of Technology
MT	Microturbine
MUD	Multi-Unit Dwelling
MV/CAT	Martha's Vineyard Commission Climate Action Task Force
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatt
MWRA	Massachusetts Water Resources Authority
NHESP	Natural Heritage Endangered Species Program
NOAA	National Oceanic and Atmospheric Administration
NOAA-HRRR	National Oceanic and Atmospheric Administration - High-Resolution Rapid Refresh
Nox	Nitric Oxide and Nitrogen Dioxide
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NWA	Non-Wires Alternatives
O&M	Operation and Maintenance
OCDE	United States Department of Energy Office of Clean Energy Demonstrations
OCED	U.S. Department of Energy - Office of Clean Energy Demonstrations
OEM	Original Equipment Manufacturer
OH	Overhead
OMS	Outage Management System
OPM	Outage Prediction System
PAs	Mass Save Program Administrators
PBR	Performance-Based Ratemaking
PEAT	Eversource Pro-Equity Advisory Team (PEAT)
PF	Power Factor
PHEV	Plug-in Hybrid Electric Vehicle

PQ	Power Quality
PSCAD	Power Systems Computer Aided Design (graphical interface)
PV	Photovoltaic
PV	Present Value
RF	Random Forest
RFL	Ready for Load
RFP	Request for Proposals
RIMS II	Regional Input-Output Modelling System II
ROW	Right-of-Ways
RTB	Run-The-Business
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	Societal Cost of Carbon
SCT	Societal Cost Test
SEIA	Solar Energy Industries Association
SEMA	Southeast Massachusetts Area
SF6	Sulfur Hexafluoride
SFM	Split Fiber Main
SHMCAP	Massachusetts State Hazard Mitigation and Climate Action Plan
SIS	System Impact Study
SMART	Solar Massachusetts Renewable Target
SOC	System Control Centers
SPP	Shared Socioeconomic Pathways
SQI	Service Quality Index
SREC	Solar Renewable Energy Certificate
ST	Steam Turbine
STATCOM	Static Synchronous Compensator
T&D	Transmission and Distribution
The Climate Act	2022 "An Act Driving Clean Energy and Offshore Wind"
The Company	NSTAR Energy d/b/a Eversource Energy
TLY	Typical Load Year
TOU	Time of Use
TUE	Joint Committee of Telecommunications, Utilities and Energy of the Massachusetts Legislature
UG	Underground
UMASS	University of Massachusetts
URB/DB	Underground and Direct Buried cable
USDA - NRCS	U.S. Department of Agriculture - Natural Resources Conservations Services
USW	United Steelworkers
UWUA	Utility Workers Union of America
V	Volt

V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
V2L	Vehicle-to-Load
V2X	Vehicle-to-Everything
VA	Volt-Ampere
VFI	Vacuum Fault Interrupting Switch
VLF	Very Low Frequency
VOC	Eversource's Voice of the Customer
VPP	Virtual Power Plant
VVO	Volt Var Optimization
W	Watt
WMA	Western Massachusetts Area
WPI	Worcester Polytechnic Institute
WTHI	Weather Temperature Humidity Index
ZEV	Zero-Emission Vehicle

Exhibit 2: ESMP Stakeholder Engagement Table

List of Stakeholder Organizations Engaged by National Grid on the ESMP

Through the ESMP process, National Grid has engaged with more than 400 **individual stakeholders** representing more than 250 **unique organizations, agencies, governmental entities, businesses and groups** on various issues related to and aspects of the ESMP, including its purpose, development, implementation, deliverability, and impact. Outreach includes webinars, meetings, workshops and dedicated informational events. Stakeholders National Grid engaged with include:

State Agencies
Office of the Attorney General
Department of Energy Resources
Executive Office of Economic Development
Massachusetts Department of Transportation
Executive Office of Labor and Workforce Development
Executive Office of Energy and Environmental Affairs, Office of Environmental Justice & Equity
Office of Climate Innovation and Resilience
Municipalities
Town of Acton
Town of Adams
City of Amesbury
Town of Athol
Town of Auburn
Town of Ayer
Town of Bedford
Town of Belchertown
Town of Beverly
Town of Billerica
Town of Boxford
Town of Brimfield
City of Brockton
Town of Burlington
Town of Carlisle
Town of Charlton
Town of Cheshire
Town of Douglas
Town of Dudley
Town of Leicester
City of East Longmeadow
Town of Egremont
Town of Erving
City of Everett
City of Fall River
City of Gardner
City of Gloucester
Town of Goshen
Town of Granby
Town of Great Barrington
Town of Hampden
Town of Hancock
Town of Hardwick

Town of Harvard
Town of Lancaster
City of Leominster
City of Lowell
City of Lynn
City of Malden
Town of Manchester-By-The-Sea
City of Medford
City of Melrose
Town of Middleton
Town of Millbury
Town of Monson
Town of Monterey
Town of Nahant
City of Newburyport
Town of New Marlborough
Town of New Salem
City of North Adams
City of Northampton
Town of Oakham
Town of Orange
Town of Oxford
Town of Palmer
City of Peabody
Town of Pepperell
Town of Phillipston
North Reading
City of Revere
Town of Rowley
Town of Rutland
City of Salem
Town of Saugus
City of Somerville
Town of Spencer
Town of Stockbridge
Town of Sturbridge
Town of Sutton
Town of Swampscott
Town of Tewksbury
Town of Topsfield
City of Waltham
Town of Ware
Town of Warren
Town of Wellesley
Town of Westminster
Town of West Stockbridge
City of Weymouth
Town of Wilbraham
Town of Williamsburg
Town of Williamstown
Town of Wilmington
Town of Winchester
City of Worcester

Elected Officials
Members of the Massachusetts House of Representatives
Members of the Massachusetts Senate
Community and Nonprofit Organizations, including Environmental Justice, Environmental and Consumer Groups
Browning the Green Space
Environmental Justice Table
Conservation Law Foundation
AARP Massachusetts
Citizens for Citizens
MASSPIRG
Worcester Community Action Council
Clean Water Action
Regulatory Assistance Project
Energy and Technology Organizations and Convenors
Advanced Energy Group
New England Power Generators Association
Northeast Clean Energy Council
Labor Organizations
IBEW Second District
United Steelworkers Union 12033
United Steelworkers Union 12012-04
Utility Workers Union of America 369
Business Organizations
Associated Industries of Massachusetts
Bristol County Economic Development Consultants
Gloucester Economic Development & Industrial Corporation
Lowell Chamber of Commerce
Massachusetts Health and Hospital Association
Massachusetts Restaurant Association
Merrimack Valley Chamber of Commerce
Retailers Association of Massachusetts
Waltham Chamber of Commerce
Worcester Chamber of Commerce

Exhibit 3: Equity and EJ Policy & Stakeholder Engagement Framework

Equity and Environmental Justice Policy and Stakeholder Engagement Framework

National Grid is working to enable net-zero by 2050 by advancing a smarter, stronger, cleaner, and more equitable energy future for the customers and communities it serves. The Company recognizes the critical need to combat climate change and drive down climate pollution and is committed to meeting the clean energy, equity, and environmental justice goals established by the Commonwealth's Clean Energy and Climate Plan. In addition to enabling equitable access to safe, reliable, and resilient energy service for customers, the Company also committed to supporting the realization of the technology, economic, and environmental benefits of the clean energy transition in all communities in a just and inclusive manner that supports the principles articulated in National Grid's Vision and Values and Responsible Business Charter.

National Grid is committed to working transparently and collaboratively with stakeholders and communities to support equity and environmental justice in the clean energy transition. The company is reviewing and enhancing its current engagement practices, with a focus on public outreach surrounding major infrastructure projects, especially in environmental justice, disadvantaged, and low-income communities. National Grid recognizes that many customers in these communities face barriers to accessing clean energy solutions, managing their energy bills, and engaging meaningfully in the stakeholder processes that enable input into the energy infrastructure and programs that impact their communities. The company also recognizes that the needs and preferences of customers across these groups are diverse and that solutions must acknowledge and reflect this diversity.

Defining Equity and Environmental Justice

Equity means engaging all stakeholders – including the Company's customers and communities – with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts, and justice disparities.

National Grid defines equity using three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Initiative.[1] These include:

- **Procedural equity,** which focuses on creating transparent, inclusive, and accessible processes for engagement such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation.
- **Distributional equity,** which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition.
- **Structural equity,** which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.

Environmental justice is defined by the United States Environmental Protection Agency as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[2] National Grid's efforts on environmental justice are informed by an understanding that the communities the Company serves vary in terms of the environmental, public

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[1] Leading with Equity Initiative | ACEEE.
[2] Environmental Justice | US EPA.

health, and economic burdens they have experienced, as well as their vulnerabilities to the risks of climate change.

National Grid Commitments

The Company will continue to work to integrate equity and environmental justice across the business by:

- Increasing transparency and education about future infrastructure investment plans, including the need for investments and the benefits and impacts to a host community;
- Engaging early with stakeholders, including directly and via trusted community sources, and enhancing open communication that supports clear and timely information sharing, community feedback, and ongoing dialogue;
- Expanding the Company's understanding of community concerns and priorities;
- Enhancing project and program outcomes by identifying opportunities to mitigate adverse impacts and support community and customer benefits;
- Reducing barriers to participation in customer programs that can benefit low-income customers and environmental justice populations;
- Partnering with National Grid communities and local organizations in support of broader social, economic, and environmental progress;
- Directly supporting economic opportunity and advancement through the development of a more local, diverse clean energy workforce and the utilization of diverse and sustainable businesses in National Grid jurisdictions; and
- Monitoring and informing on the Company's progress in supporting equity and environmental justice on a regular and transparent basis.

Operationalizing Equity and Environmental Justice

National grid recognizes that fully integrating equity and environmental justice into its operations, planning, programs, and day-to-day business will require new efforts that build upon existing initiatives within the Company and full operationalization of equity and environmental justice through an intentional approach that will take time. The Company is actively working to build upon and learn from its existing efforts, create new processes and procedures to advance the intentions outlined above, and to develop the necessary training and resources for its employees. The Company is working to establish a cross-functional team with dedicated leadership and transformation expertise to ensure that key business areas are equipped to implement this framework. In addition, National grid is working to engage external perspectives to inform these organizational efforts.

These efforts will continue to build upon and be informed by multiple successful recent and ongoing efforts including:

- Processes and practices to mitigate environmental impacts of construction.
- Public outreach and stakeholder engagement via multiple channels and with translation where needed in support of obtaining project permits and approvals and addressing construction impacts.

- Launching the Indigenous Peoples Initiative, a three-part program designed to strengthen the Company's relationships with Federally Recognized Tribes within its New England operating area while creating benefits for those Indigenous Communities.[3]
- Consideration of input from environmental justice stakeholders in the design of the Company's customer programs. National Grid's Energy Efficiency Programs include specific goals related to achievement of equitable outcomes among specific customer segments and include explicit commitments around service to environmental justice populations. The Company's Electric Vehicle programs include enhanced incentives for public charging and residential customers in environmental justice communities, as well as direct support of fleet electrification to reduce local air pollution.
- National Grid's Grid for Good program establishes a framework for National Grid's social responsibility priorities that focuses on three pillars: (1) workforce development and STEM education, (2) economic opportunity and social justice, and (3) clean energy and sustainability; all underpinned by a partnership model focused on delivering outcomes, with a focus on environmental justice and underrepresented communities.
- The Company's strategic workforce development program provides education, training, and development opportunities for young people and adult learners from underrepresented communities throughout the Commonwealth in partnership with thirteen academic and community-based organizations.

Evaluating the Company's Progress

National Grid intends this framework to be a living document, updated and modified based on stakeholder feedback and lessons learned through experience. The Company is committed to collaborating with stakeholders to inform future review and development of these efforts.

[3] The Indigenous Peoples Initiative includes development of an Indigenous Peoples Statement outlining out commitments to and respect for those Indigenous Communities, a draft of which was shared with the New England Federally Recognized Tribes for feedback. It also includes recently hiring a New England Indigenous Communities Liaison, establishing community engagement projects based on input from the New England Tribes, and conducting employee education events focusing on Indigenous history and culture. The Initiative will benefit Indigenous Communities, National Gird customers, and the Company's workforce, and is a first step in strengthening relationships and achieving shared environmental priorities.

Exhibit 4: National Grid New England Indigenous Peoples Statement

National Grid New England Indigenous Peoples Statement

New England Power Company, Massachusetts Electric Company, Nantucket Electric Company and Boston Gas Company, all d/b/a National Grid[1], are committed to recognizing and honoring the rich history, diversity, and culture of Indigenous Peoples[2] within our service area and beyond. In doing so, we acknowledge the inherent sovereignty[3] of Federally Recognized Tribes.[4]

Our overarching goal is to cultivate enduring, respectful, and mutually beneficial relationships that yield positive outcomes for the aforementioned Tribes, National Grid, our affiliates, customers, and the planet. Guided by the 7th Generation Principle[5] , we aim to make informed decisions that benefit our communities and the environment for generations to come.

National Grid's primary contribution to improving the global environment is facilitating the transition to a clean, fair, and affordable energy future. This involves facilitating the development of low-carbon, renewable energy sources across New England, including the development of new transmission and distribution facilities and/or the replacement or refurbishment of existing infrastructure. Throughout this process, we are committed to minimizing environmental impacts and waste to the greatest extent practicable.

Recognizing the critical nature of this work, we seek to protect our planet while ensuring reliable service for our customers. We approach this task by consulting actively with the Federally Recognized Tribes in our New England region, showing respect for the overall environment and acknowledging resources of cultural and historic significance to those

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[1] For purposes of the Indigenous Peoples Statement for New England, "National Grid" includes New England Power Company, Massachusetts Electric Company and Boston Gas Company.

[2] National Grid understands that preferences around the language used to describe Indigenous Peoples differs from community to community and person to person. In this document, we have used the terms "Indigenous" and "Federally Recognized Tribes" in an effort to be respectful and inclusive.

[3] A simple definition of "sovereignty" is the right or ability of a group to self-govern. The United States Government recognizes the inherent sovereignty of Federally Recognized Tribes - as their sovereignty derives from the history of Indigenous Nations engaging in self-governance long before the colonization of North American by Europeans. For additional information on the topic of sovereignty, please see https://www.bia.gov/frequently-asked-questions.

[4] National Grid has shared this Indigenous Peoples Statement for New England with representatives of the Mashpee Wampanoag Tribe, the Narragansett Indian Tribe, the Stockbridge-Munsee Band of Mohicans, and the Wampanoag Tribe of Gay Head Aquinnah to obtain stakeholder feedback. It is our intention that this document and its implementation reflect the perspectives of the aforementioned Federally Recognized Tribes on whose ancestral lands we build and maintain infrastructure and otherwise operate our business.

[5] The 7th Generation Principle is an Indigenous philosophy that encourages decision makers to: 1. consider the impacts of their decisions seven generations into the future and 2. make decisions that result in positive outcomes seven generations into the future.

communities. We also hope, that through these efforts to strengthen relationships with the aforementioned Federally Recognized Tribes, we ensure that they have a meaningful voice in the clean energy transition.

To achieve these goals, National Grid's initial efforts include:

- Actively engaging in relationship-building with the following Federally Recognized Tribes:
    - The Mashpee Wampanoag Tribe;
    - The Narragansett Indian Tribe;
    - The Stockbridge-Munsee Band of Mohicans; and
    - The Wampanoag of Gay Head Aquinnah.
- Identifying and establishing partnerships between National Grid and the aforementioned Tribes, based on input from tribal leaders and members, to support ongoing community initiatives.
- Engaging in meaningful collaboration with the aforementioned Tribes to avoid, minimize, and/or mitigate impacts to natural, cultural, and historic resources.
- Taking proactive steps to educate our employees about Indigenous history, culture, and the significance of State and Federal Recognition.

These efforts mark the first steps in strengthening relationships and achieving shared environmental goals. We anticipate that our initiatives will evolve and grow, and will at times include State Recognized Tribes and other Tribal entities. We look forward to collaborating with Indigenous neighbors, customers, and colleagues.

For any questions or comments, please reach out to Danielle Oakes, New England Indigenous Communities Liaison.

Danielle Karahkwison Oakes

New England Indigenous Communities Liaison

Stakeholder Management and Major Permits

508-851-7575 | Mobile

danielle.oakes@nationalgrid.com

Exhibit 5: ESMP Integrated Timeline

National Grid ESMP Integrated Timeline

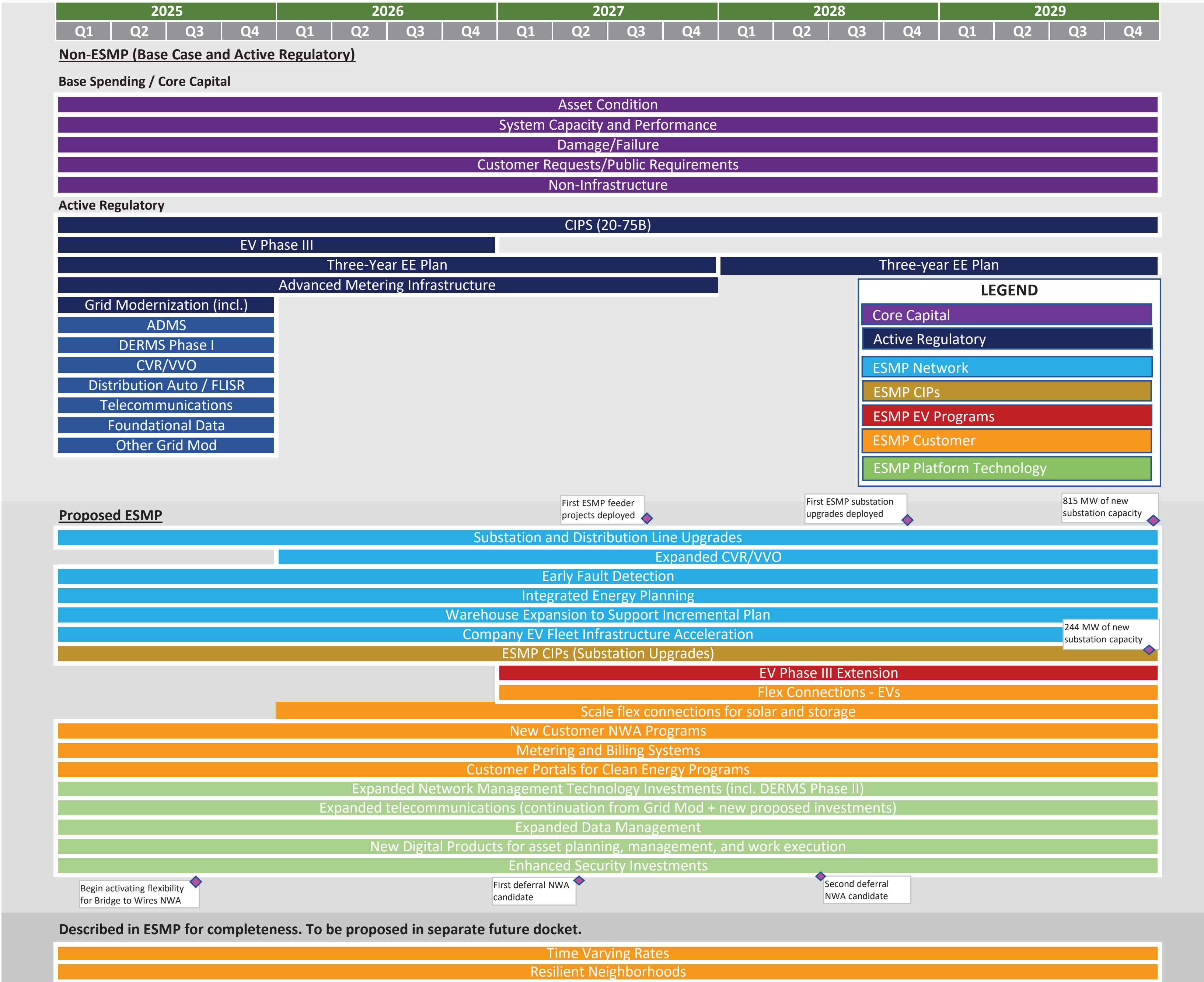

Exhibit 6: ELF Report – Feeder

MASSACHUSETTS ELECTRIC COMPANY

NANTUCKET ELECTRIC COMPANY

2023 to 2050 Electric Peak (MW) Feeder-level Forecast

December 2022

Original: December 16, 2022

Load Forecasting & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

<u>Revision History</u>

Version	Date	Changes
Original	12/16/2022	- ORIGINAL

<u>General Notes</u>:

- Peak load data is October 2022; projections from 2023 forward
- Energy efficiency, electric heating, solar, energy storge and demand response is internal data vintage August 2022.
- Electric vehicle data is POLK data vintage June 2022 with actual to the end of 2021
- 2020 American Community Survey 5-year from U.S. Census Bureau[1]

Report Contact(s):
Alex (Henfang) Deng
hengfang.deng@nationalgrid.com
Rain (Jingrui) Xie
jingrui.xie2@nationalgrid.com

[1] https://www.census.gov/data/developers/data-sets/acs-5year.html, retrieved September 2022

CONTENTS

1. Summary

National Grid's Massachusetts electric system serves over 1.35 million customers (approximately 43% residential, 44% commercial, and 13% industrial by energy volume) in the State of Massachusetts. It spans across the entire state, including all or some portions of Berkshire, Bristol, Essex, Franklin, Hampden, Hampshire, Middlesex, Nantucket, Norfolk, Plymouth, Suffolk, and Worcester Counties. The feeder-level forecasts are provided for 987 feeders in the Company's Massachusetts electric system. The forecasting process takes the system-level load growth projection and outlook on distributed energy resources (DER) as inputs. Detail on the system level load forecast and DER projections are in "Massachusetts Electric Company & Nantucket Electric Company 2023 to 2050 Electric Peak Forecast" ("System Level Peak Report"). It then leverages the regional specific factors such as demographic information, land availability, etc. to allocate the system-level forecasts to the feeder level. The DER includes energy efficiency, solar-photovoltaic, energy storage, electric vehicles, and electric heat pumps. This report focuses on discussing the methodologies of developing the feeder-level forecasts.

2. Base Load Forecasting and Profiles

2.1 Base Load Annual Peak Forecast

The base load is defined as the peak load before any *incremental* DER impact; however, it includes historical embedded DER impacts. The historical base load is weather adjusted to reflect the 50/50 and 90/10 weather scenarios[2], and then grow at the same rate as the Power Supply Area (PSA) that it falls into. There are 18 PSA areas in the Company's Massachusetts's service territory, which cover all the 987 feeders that are being forecasted. The PSA-level load growth forecast is discussed in the System Level Peak Report. This process results in a point annual peak base load forecast between 2023 and 2050 for each feeder. The future incremental DER impact is not part of this base load forecasting process and will be adjusted for later in the process.

2.2 Base Load Annual Profile

For each feeder, the point base load forecast of each year is used in an annual hourly load profile to derive the hourly base load profile for each hour of each year through the forecast horizon. First, the annual hourly normalized load profile (i.e., the 8760 load profile) is derived from the typical load shapes from the Company's load research team's work which is published on the Company's data portal[3]. The typical load shapes are available for typical residential, typical commercial, and typical industrial customers, respectively. The feeder-level forecasting work takes the customer type (i.e., residential, commercial, and industrial) mix of each feeder to derive one single weighted

---

[2] Normal 50/50 weather is defined as the average weather on the past 20 annual peak days. Extreme 90/10 weather is such that it is expected that it will only be exceeded 10% of the time. Please refer to the System-Level Peak Report for detailed discussions on weather scenarios. The feeder-level work uses the same weather scenario definitions developed for the ISO zone that each feeder falls into. There are three ISO zones that the Company serves in MA including Northeastern MA and Boston area (NEMA), Southeastern MA (SEMA), and West-central MA(WCMA)

[3] https://www9.nationalgridus.com/energysupply/load_estimate.asp, retrieved October 2022

load profile using the load shapes of each customer class and the customer mix, i.e., residential, commercial, and industrial, as the weight as shown in Formula (1) and Figure 1.

$$8760\ Base\ load\ profile = \frac{[(R * LS_r) + (C * LS_c)) + (I * LS_i)]}{(R+C+I)} \quad \text{.......................................} \quad (1)$$

where, LS_r = Typical Residential Customers Load Shape,

LS_c = Typical Commercial Customers Load Shape,

LS_i = Typical Industrial Customers Load Shape,

R = number of residential, C= number of commercial, I = number of industrial customers,

Next, the normalized annual hourly profile is multiplied by the point base load peak forecast to obtain the final annual hourly load profile for each feeder.

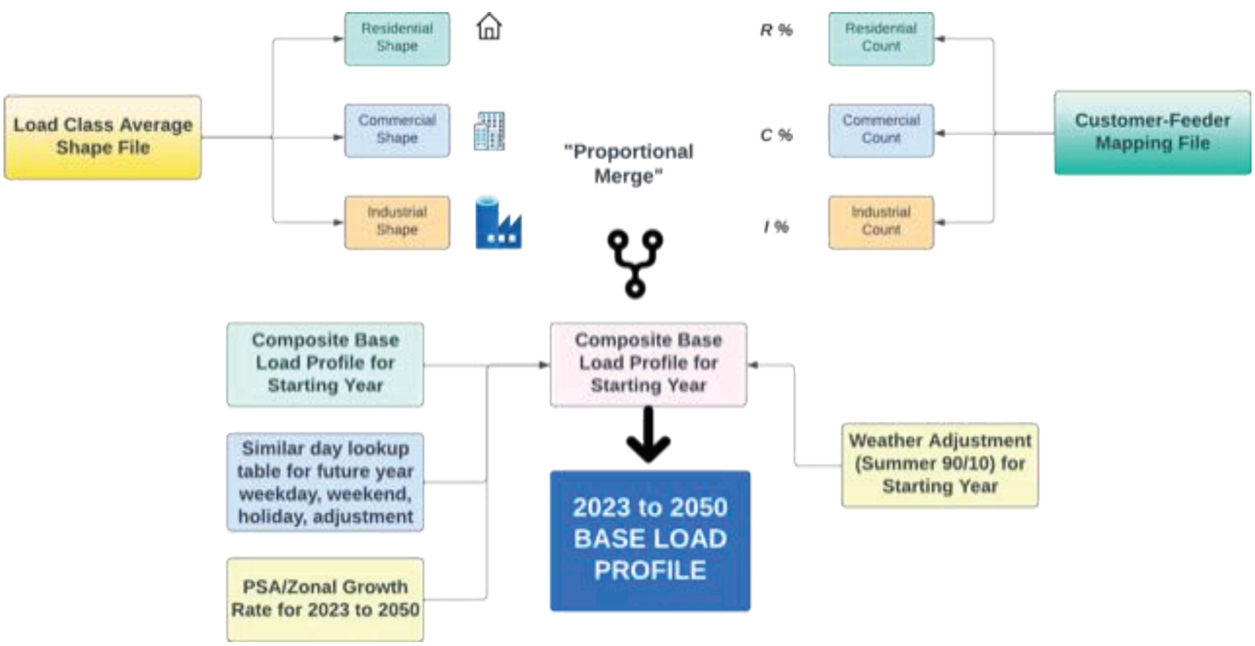

Figure 1: Flowchart of Generating 8760 Profile for the base load

3. Distributed Energy Resource Methodology

This section describes the methodology for allocating the system-level DER forecasts to the feeder level and developing the annual DER load profiles. Since historical DERs are embedded in the historical base load, all DERs are rebased to zero starting in the first forecast year to eliminate double counting of DERs.

3.1 Energy Efficiency

Feeder Level Allocation:

The forecast of annual peak contribution of Energy Efficiency (EE) measured at the Company's Massachusetts electric system level is described in the System-Level Peak Report for base, low, and high scenarios. The system-level EE peak saving is then allocated to different ISO zones in the Company's electric service area based on each zone's peak load contribution to the system. The zonal-level annual incremental EE growth is then allocated to the feeders in the zone based on the annual energy share of each feeder within the zone. The same process is applied to allocate base, high, low EE projections to the feeders to create the base, high, and low EE cases at the feeder level.

Profile Description:

A normalized typical daily profile is assumed for each month of a year. Figure 2 shows the normalized typical daily profile. All days in a year share this same normalized daily profile, however, it is scaled differently for each month based on monthly variation in EE impact. Figure 3 presents the normalized monthly variations of EE savings. EE saving estimations for the typical day profile and the monthly variations are based on the types of EE programs that the Company have customers enrolled in and the typical customer consumption patterns. Figure 4 gives an example of hourly saving through a year at a randomly selected feeder.

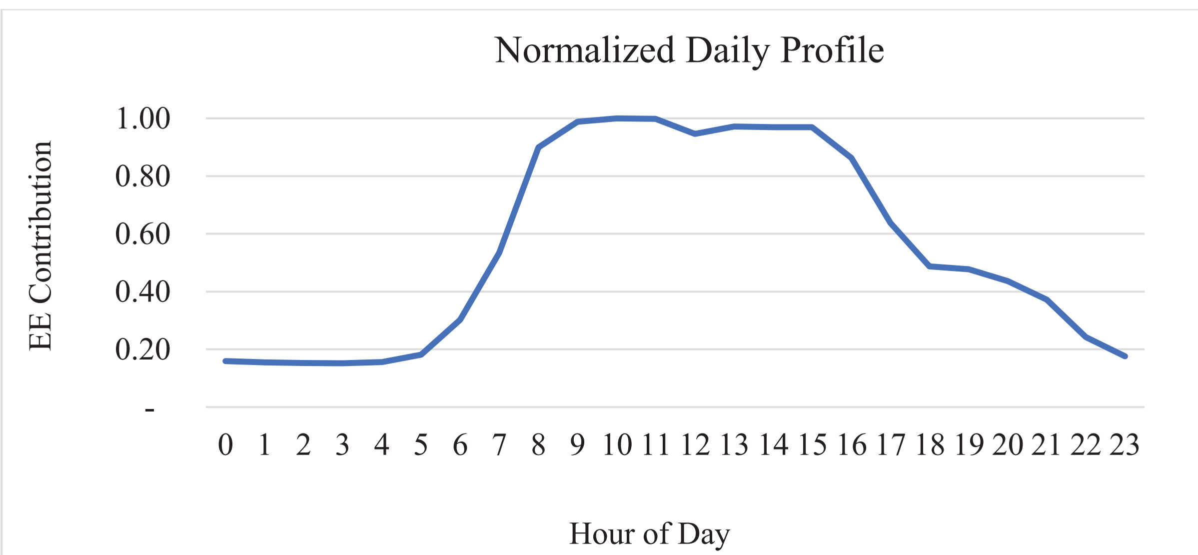

Figure 2: Estimated normalized hourly EE savings

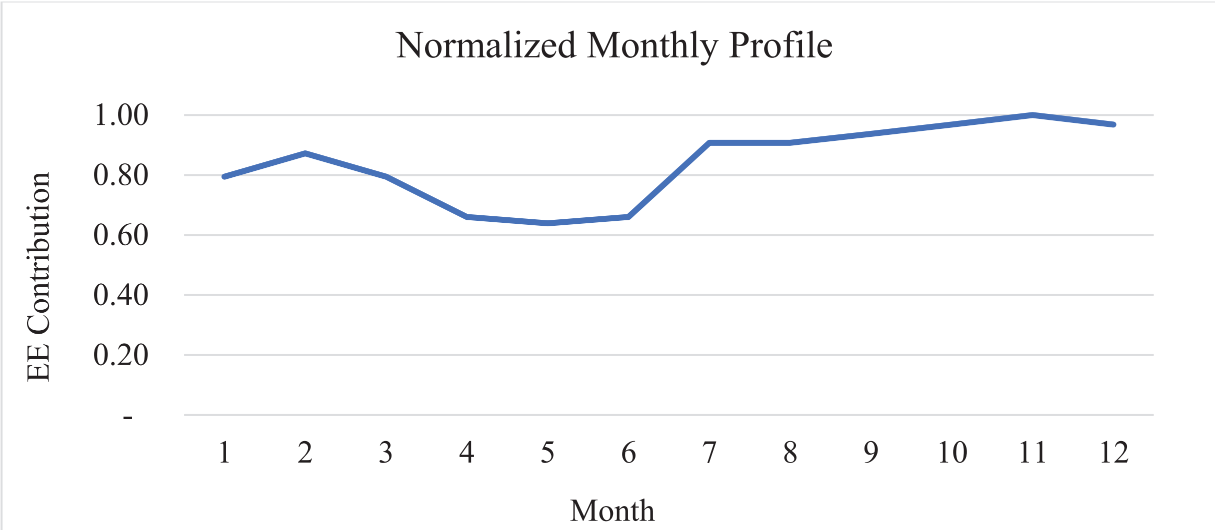

Figure 3: Estimated normalized monthly EE savings

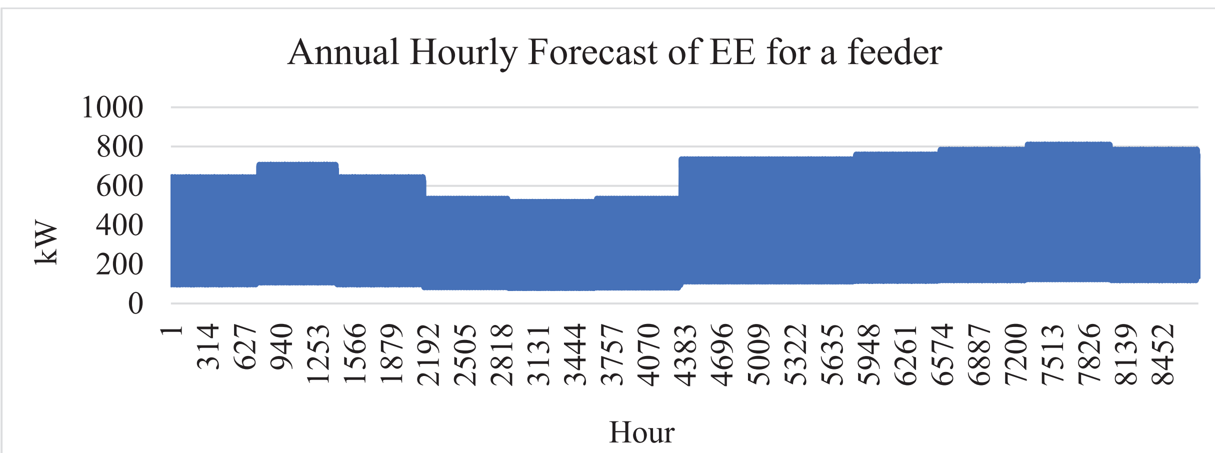

Figure 4: Estimated hourly EE saving (kW) at a randomly selected feeder

3.2 Rooftop Solar-Photovoltaics

The system-level rooftop PV nameplate projection is first allocated to electric customer accounts that the Company serves. Then, the customer account level projection gets aggregated to each feeder from which these accounts get fed. The process of allocating system-level projection to the customer account level starts with scoring electric customer accounts[4] for their likelihood of adopting rooftop PV. The score considers factors including but not limited to household income, employment stability, homeownership/renter status, etc. For example, homeowners with higher household incomes and more stable employment status are more likely to become PV adopters and thus have higher scores. All the customer accounts are scored and ranked from the most likely

[4] Customers who have already adopted rooftop PV are excluded from the allocation process.

adopters to the least likely adopters. The system level projection is allocated to top-ranked customer accounts until the total allocated nameplate kW reaches the system-level projection.

The hourly impact of rooftop PV is estimated from using a typical meteorological year from National Renewable Energy Laboratory (NREL)[5] to convert nameplate to power generation.

3.3 Non-Rooftop Solar-Photovoltaic

For the near term, the non-rooftop PV nameplate projection is based on projects in the application queue and their estimated connection date. The annual aggregated incremental nameplate connection is bounded by the system-level projection.

After this and for the period between the late 2020s and 2050, the system-level annual incremental projection is allocated to the available land parcels that are most likely to develop PV. Available land parcels are ranked by their likelihood to develop PV and then the system-level projection is allocated to the highest ranked parcels each year until the system-level projection is met. The Company leverages the renewable interconnection analysis tool developed by GridTwin[6] for analyzing land parcel availability and ranking PV projects. The GridTwin tool considers land availability based on land use codes, environmental and cultural restrictions, as well as land characteristics (e.g., slopes). It ranks available and suitable land, by calculating the Internal Rate of Return (IRR) to rank the profitability of developing PV projects on each land parcel. The compensation components considered in the IRR calculation are primarily based on incentives from MA SMART programs. The cost components considered in the IRR calculation include land cost, interconnection cost, capital cost, and annual operation & maintenance costs.

The hourly impact of non-rooftop PV is estimated from using the same typical meteorological year weather from NREL as rooftop PV to convert nameplate to power generation.

3.4 Storage

For the near term, the storage projection is based on projects in the application queue and their estimated connection date. In the medium and long term, the storage projection assumes achieving the State's decarbonization policy target. This results in a storage projection reaching about 18% of the estimated PV connection.

A peak shaving storage discharging profile is assumed thus the storage is expected to discharge during typical peak hours in a day and charge during the hours when PV is expected to generate or late-night hours.

[5] https://nsrdb.nrel.gov/data-sets/tmy, retrieved September 2022
[6] https://gridtwin.energy/

3.5 Light-duty Electric Vehicles

Allocation Overview

The Light Duty Electric Vehicle (LDEV) forecast includes charging demand for both battery electric vehicles (BEV) and Plug-in Hybrid Electric Vehicles (PHEV). The allocation process takes the system-level LDEV adoption projection for the whole service territory and identifies where and when the adoption will happen at the more granular feeder level. The majority of the light-duty EVs are for personal use or are being allocated to residential customers, while about 6%[7] of the total projected number of light-duty EVs are expected to be for commercial use and are being allocated to commercial and industrial customers. For residential LDEV, we use a study of the propensity for EV adoption to forecast the annual increment in EV adoptions and charger installation, inputs for such models are state-level projections for long-term LDEV growth provided as described in the System Level Peak Report. The Zip Code Tabulation Areas (ZCTA)-level socio-economic information[8] is primarily utilized for the propensity model, and the key variables are median household income, the fraction of individuals with degrees that are higher than college, and commuting patterns. If a feeder serves multiple ZCTAs, we compute the weighted average score with the number of residential accounts as weights. Overall, neighborhoods with higher income level, higher education rates and higher are projected toexperience higher adoption. As for commercial light-duty EVs, the annual incremental vehicle adoption for each feeder is proportional to the number of Commercial and Industrial customers on each feeder.

Profile Description

As the EV adoption rates increase, the annual energy demand which is primarily determined by the vehicle miles traveled (VMT) for electric vehicles also shifts. Figure 5 shows the temporal progression of the energy demand per LDEV in kW throughout 2050 that are from NHTSA (National Highway Traffic Safety Administration)[9]. We can see that the VMT-driven annual demand steadily increases until 2040 and remain stable after that.

[7] https://www.iso-ne.com/static-assets/documents/2021/12/lf2022_draft_transp_elec.pdf, ISO-NE, December 2021
[8] https://www.census.gov/data/developers/data-sets/acs-5year.html, retrieved October 2022
[9] https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952, retrieved July, 2022

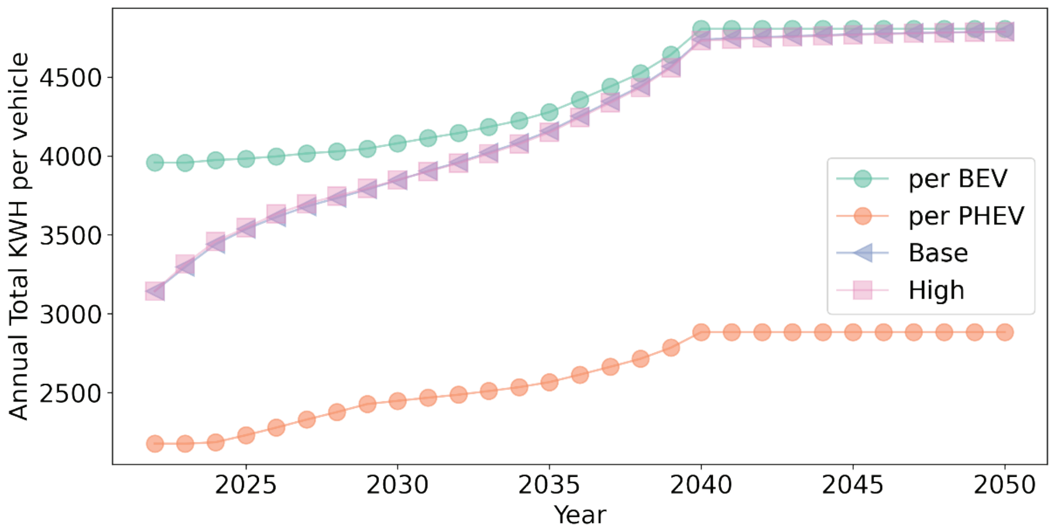

Figure 5: Annual Energy Demand per Light Duty EV

We then leverage the charging profiles and temporal patterns developed by ISO-NE[10] and BloombergNEF (BNEF)[11] to project the charging demand for different charging location types (home/work/public) at different times and aggregate them to the corresponding feeder. Figures 6 and 7 below depict the detailed charging demand for both managed and unmanaged charging scenarios. In the unmanaged scenario, a dual peak pattern is observed on weekdays with the evening peaks (between 7 and 9 PM) generally larger than the morning peaks. However, the evening peak shifts to 10 PM in the managed charging profile. The managed charging scenario assumes 75% of the LDEV owners have access to the home chargers, and 75% of those do not charge their vehicles at home during the peak hours (4PM to 10PM). Away-from-home charging is assumed to remain unmanaged.

[10] https://www.iso-ne.com/static-assets/documents/2021/12/lf2022_draft_transp_elec.pdf, retrieved December 2021
[11] https://about.bnef.com/electric-vehicle-outlook/, retrieved June 2022

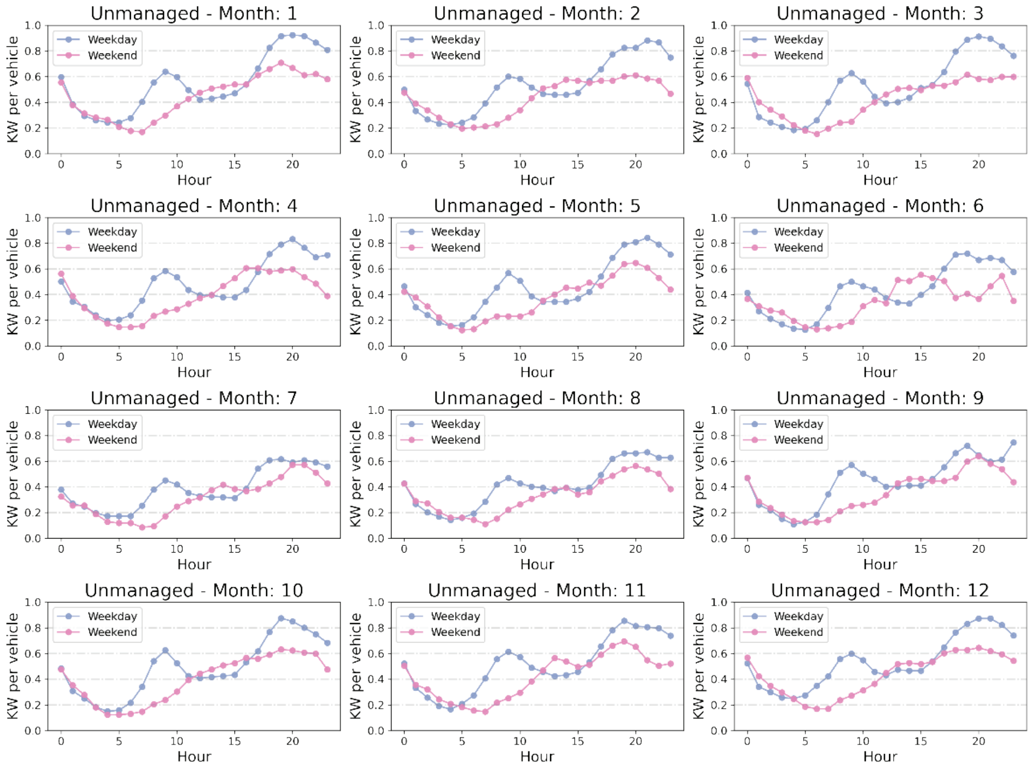

Figure 6: Unmanaged Charging Profiles per LDEV

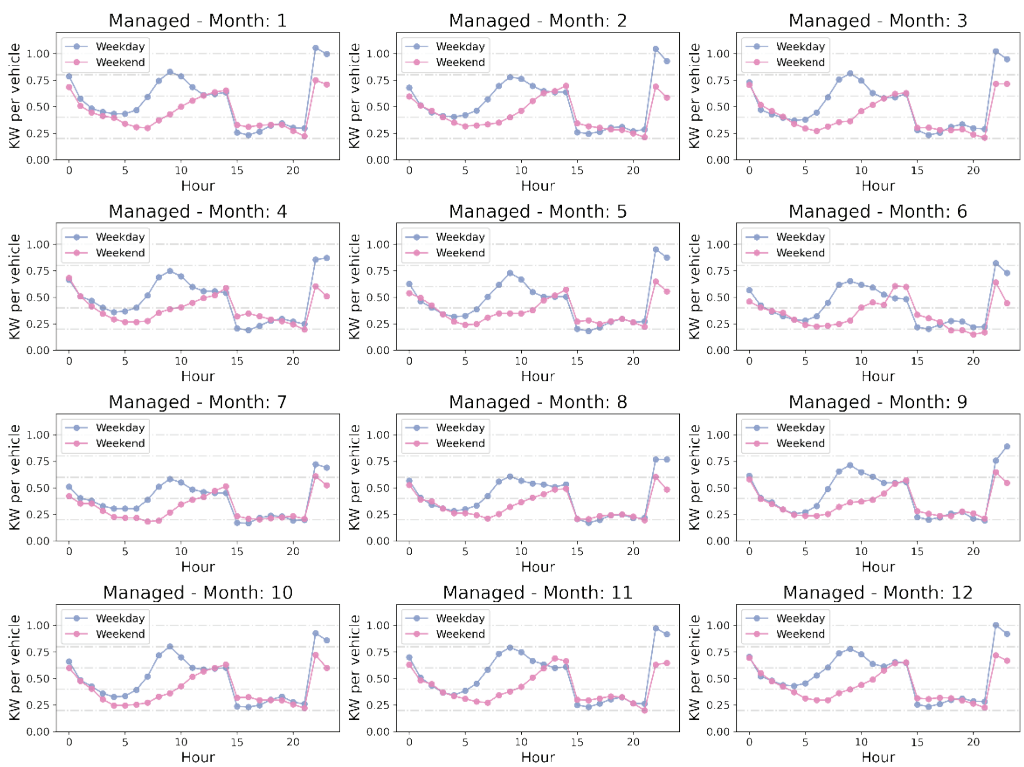

Figure 7: Managed Charging Profiles per LDEV

After estimating the hourly total charging demand for all the electric vehicles, we further break down the charging demand into three categories: home, work, and public charging. The fraction from each category is shown in Figure 8 below and at each hour by leveraging the NREL EVI Pro Lite Load Profile[12] (Scenario 52 with 75% home charging access; minor adjustment on work fraction on weekends have been implemented) by day type and hour of day, such that the sum of all three categories always equals one. We can see that in most hours after 4 PM and before 3 AM on weekdays, home charging is about 80% of all charging. Workplace charging events mostly take place between 6 AM and 2 PM, peaking around 8 AM with a 60% peak. Public charging peaks on weekends around 10 AM. The projected number of workplace and public chargers are provided by an external vendor.

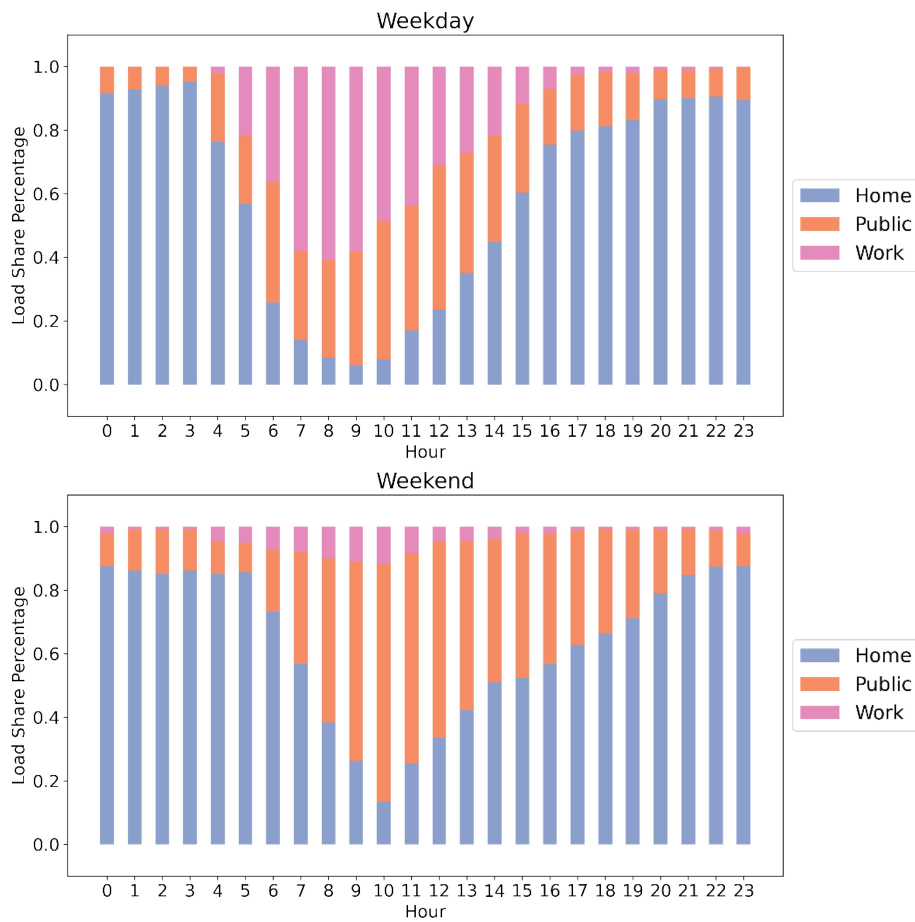

Figure 8: Hourly Charging Demand Allocation based on Charging Type

12 https://developer.nrel.gov/docs/transportation/evi-pro-lite-v1/, retrieved September 2022

3.6 Electric Heat Pumps

Allocation Overview

The electric heat pump allocation process primarily uses the system-level annual forecasted number of heat pumps (see System Level Peak Report), the up-to-date heat-pump adoption records from the Company's Customer Energy Management team (CEM), and the House Heating Fuel type from the Census Bureau on the ZIP Code Tabulation Area (ZCTA) level. For the first five years (2023-2027), we leverage the CEM historical and forecasted heat pump installation information and assume the heat pump adoption will follow the up-to-date heat pump incentive program participation. For the next six years (2028-2033), the allocation is primarily driven by the number of households that use delivered fuel including bottled or tank gas, fuel oil, kerosene, coal, wood etc. The estimation is through a similar ZIP-to-Feeder allocation process and by the end of 2033, it is projected that most of the households with delivered fuel as the main source will have electrified heat. The full electrification of delivered-fuel heating customers takes place during 2034. For the remaining years in the forecast horizon, the heat pump adoption on each feeder is driven by the number of the utility gas heating households.

Profile Description

The seasonal energy consumption of EH were from the Company's CEM team based on estimated consumption of existing EH units connected through the Company's programs. Then, the winter seasonal energy is proportionally allocated to the heating-needed months including all winter months (November to March) and some shoulder months (October, April, and May). This allocation is based the Company's gas customers' heating consumption. The annual energy consumption of a partial heat pump is 4,461 kWh and the annual consumption of a full heat pump is 8,871 kWh. The definition of full and partial heat pump is aligned with the system-level peak forecast: a full application is defined as a heat pump unit that will serve the all the heating and cooling in the building; a partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season. The ratio of full-to-partial heat pumps varies between the base, high, and low cases. Figure 9 shows that the average annual energy consumption per heat pump is different for each case because of the shifting ratio. For the low and base, we can see that such number starts climbing after 2030 as the full heat pumps become more prevalent. In the high case we see a drastic rise beginning in 2026 due to accelerated adoption of full heat pumps.

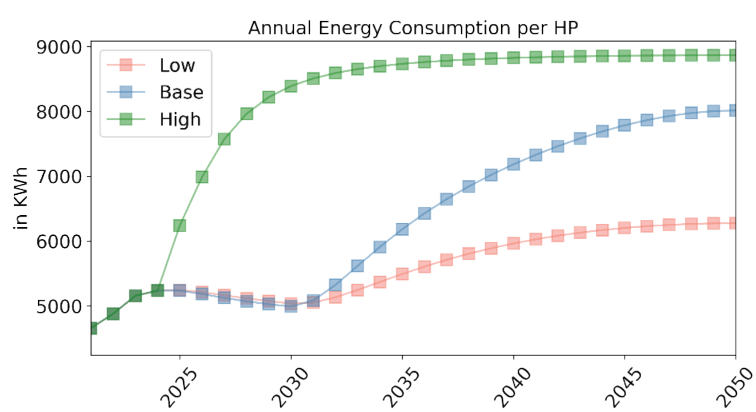

Figure 9: Annual Energy Demand per Heat Pump

Figure 10 below demonstrates the detailed heating/cooling load patterns for both full and partial heat pumps. In the very cold winter months, a dual-peak pattern is observed with morning peaks generally higher than afternoon peaks. Furthermore, the difference between full and partial heat pumps is more pronounced as the partial heat pump in those months is frequently used as a supplementary heating source for zoning or heating individual rooms. We assume there is no demand in the shoulder months of April and October.

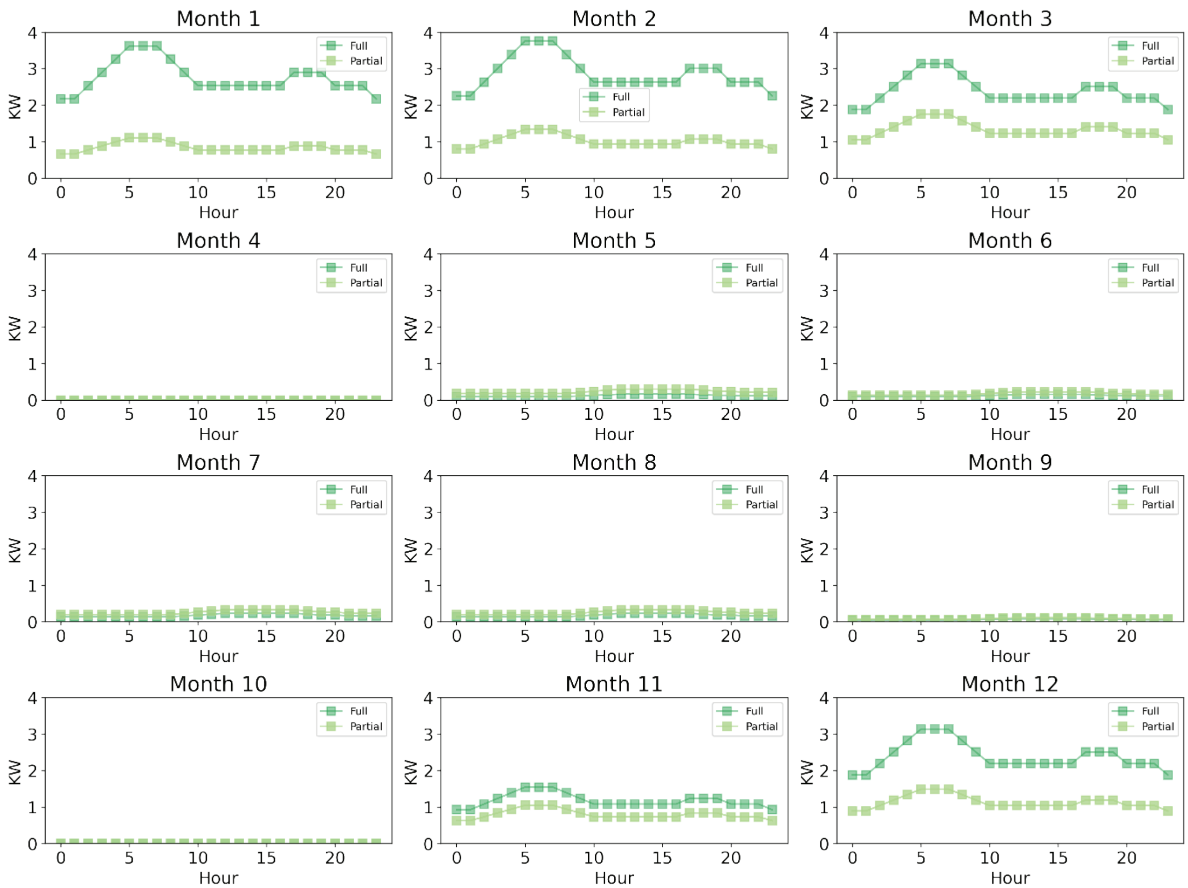

Figure 10: Energy Consumption Profiles per Heat Pump

4. Peak Load Forecast Integration

The projected base load is adjusted for the impact of each DER technology discussed in the previous sections. This generates the post-DER load forecast. Figure 11 shows the distribution of feeders' average annual peak growth rate between year 2023 and 2050. The median of the growth rate is 2.6% and the majority of the feeders have a growth rate ranging from 1% to 4%. High electrification penetration is the main driver of the high growth rates showing on the right tail in the distribution.

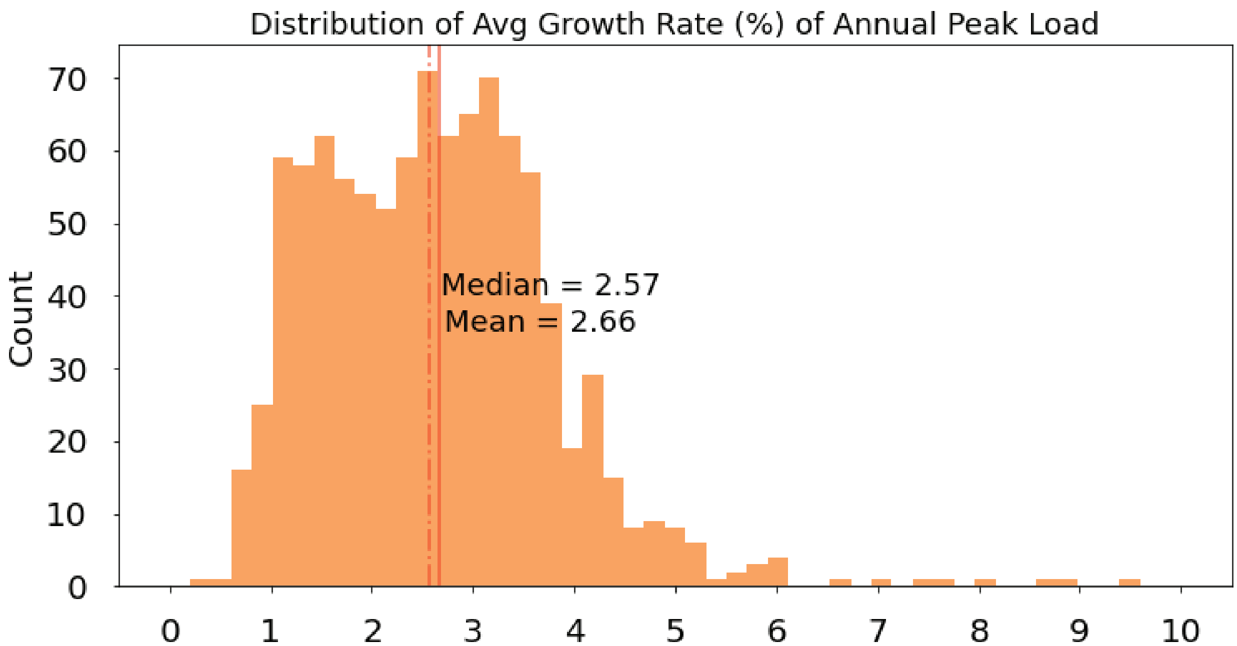

Figure 11: Distribution of average annual growth rates (%)

Figure 12 presents the same average annual growth rate (%) on a map: each marker represents the centroid of a feeder that is forecasted. The growth in the southeast, northeast, and Worcester regions are mainly driven by the EV growth. In the west central area, the current high percentage of delivered fuel as heating source is forecasted to be largely replaced by electric heat pumps thus driving load growth.

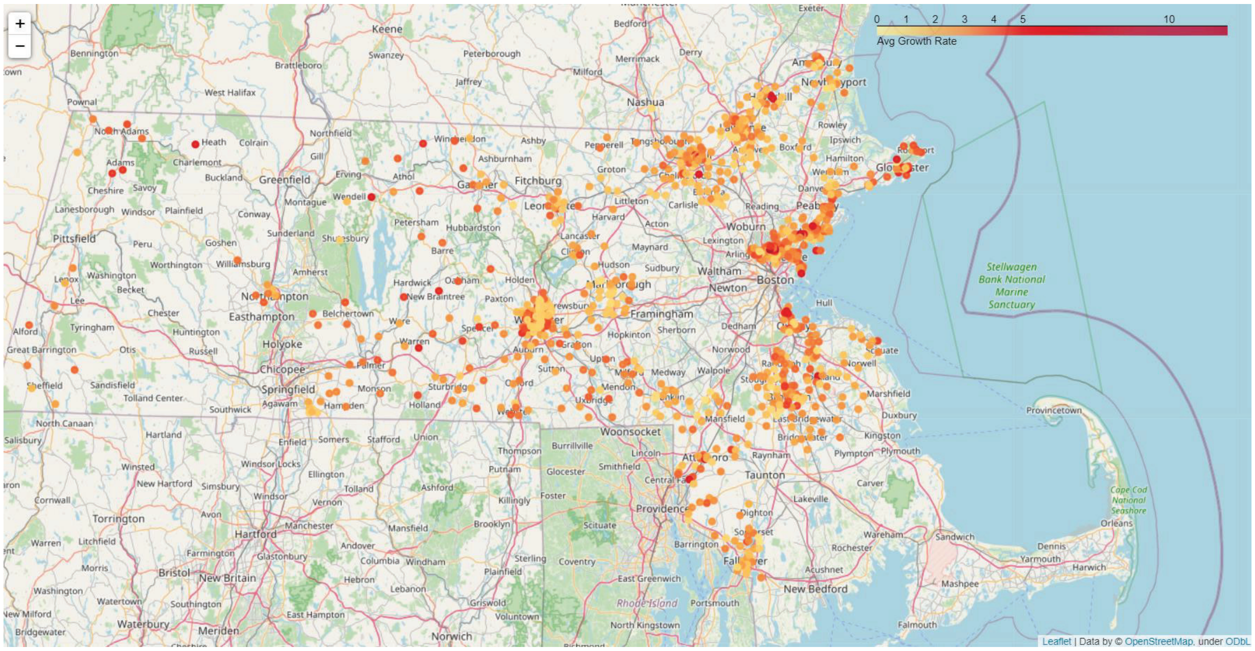

Figure 12: Average annual growth rate (%) of feeders

About 77% of the forecasted feeders are expected to switch to a winter peaking system by 2050. The majority of the switch is expected to occur in the late 2030s and beyond.

Exhibit 7: ELF Report – Peak

MASSACHUSETTS ELECTRIC COMPANY

NANTUCKET ELECTRIC COMPANY

2023 to 2050 Electric Peak (MW) Forecast

May 2023

Rev 3, 05/02/2023

Economics and Load Forecasting
Load Forecasting & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/21/2022	- ORIGINAL
Rev 1	03/01/2023	- added study area forecast - updated power supply area forecast
Rev 2	03/15/2023	- updated forecasts with updated EH profile
Rev 3	05/02/2023	- updated study area and power supply area forecasts

General Notes:

- Hourly load data through August 2022; projections from 2022 winter forward.
- Economic data is from Moody's vintage August 2022.
- Energy Efficiency, electric heating, solar, energy storge and demand response is internal data vintage August 2022.
- Electric Vehicle data is POLK data vintage June 2022 with actual to the end of 2021.
- Peak MW and Energy GWH source the ISO-NE/MDS meter-reconciled data (Jan. 2003 to Apr. 2022); internal unreconciled **preliminary** data (May 2022 to Aug. 2022).
- Peak load data is metered zonal load, without ISO bulk system losses.
- References to "Zones" refers to ISO-NE designations; all data is National Grid's service territory information within these zones.
- New this year:
    - Extending forecast horizon to 2050
    - Providing a managed light-duty electric vehicle charging scenario
    - Differentiating electric heat pump by full and partial

Report Contact(s):
Jingrui (Rain) Xie
jingrui.xie2@nationalgrid.com

David Reaves
David.Reaves@nationalgrid.com

CONTENTS

Summary

National Grid's US electric system is comprised of three companies serving over 3 million customers in Massachusetts and upstate New York. The three electric companies are: Massachusetts Electric Company and Nantucket Electric Company, serving 1.35 million customers in Massachusetts; and Niagara Mohawk Power Company, serving 1.7 million customers in upstate New York. Figure 1[1][2] shows the Company's service territory in the U.S.

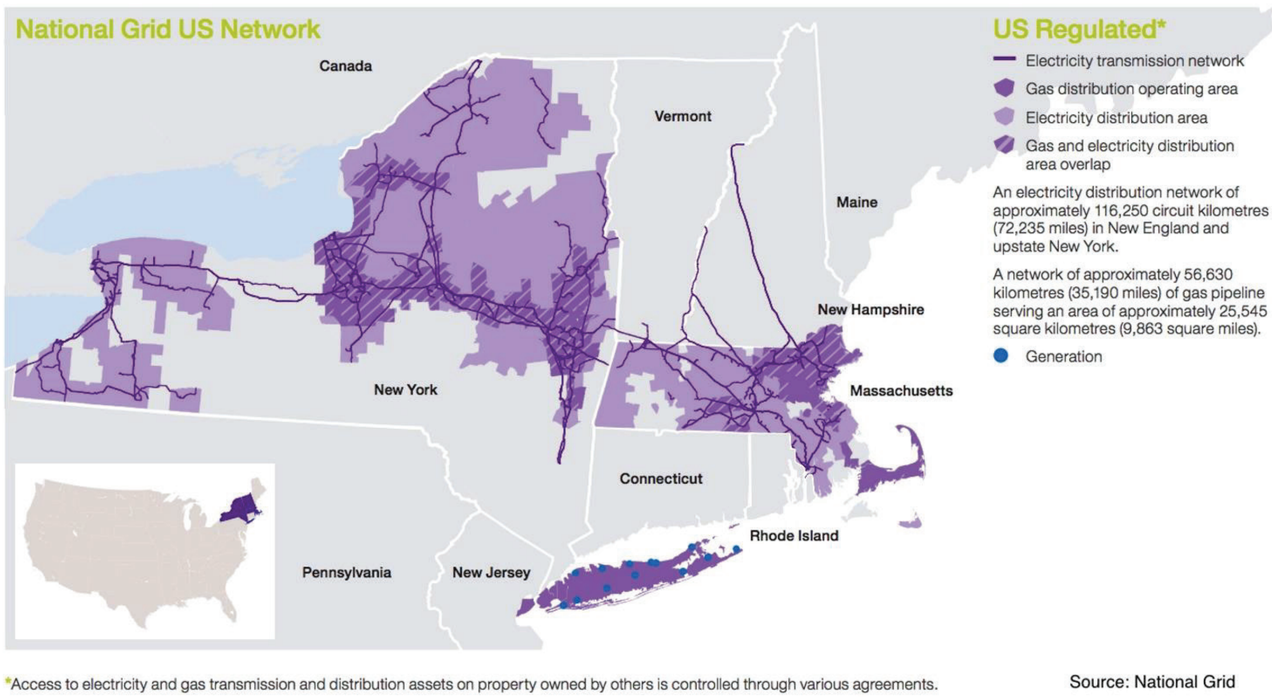

Figure 1: National Grid U.S. Service Territory

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts.

<u>Massachusetts Electric Company (MECO)</u>

MECO's peak demand in 2022 was 4,657.4 MW[3], on Monday, August 8 at hour-ending 18. This 2022 peak was 9.6% below the company's all-time high of 5,152 MW reached on Wednesday, August 2, 2006.

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[1] National Grid also serves gas customers in these same states which are also shown on this map.
[2] As of May 22, 2022, National Grid has completed the sale of The Narragansett Electric Company ("NECO") to PPL Rhode Island Holdings, LLC. Thus, Rhode Island is not part of National Grid's U.S. electric distribution system after the completion of the sale.
[3] Meter Data Service's system level PRELIMINARY and subject to change.

This summer's weather for MECO's peak[4] was considered hotter than average (or 'normal'). The peak weather fell in the 88th percentile of peak weather over the last 20 years. This means that 88% of summers had peak weather that was cooler and only 12% of summers had peak weather that was warmer. This year's peak is considered 95.0 MW higher than the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis this year's peak was estimated to be 4,562.5 MW, an increase of 1.2% compared to last year's weather-adjusted 'normal' peak.

MECO expects slightly growing post-DER peak values – i.e., on average, 0.7% per year, from its 2022 level in the next five years. The system remains summer peaking through the year 2035. However, the peak hour is expected to shift from late afternoon/early evening to later in the evening. During these later hours, EV charging demand increases and PV savings becomes less or not available.
Starting in 2036, MECO is expected to become a winter peaking system. This change is mainly driven by the increasing beneficial electrification in the transportation[5] and building sectors. Figure 2 shows the projected annual peak (solid blue line) and the summer peak (dashed blue line) under the normal weather, as well as the annual peak under two extreme weather assumptions, namely 90-10 and 95-5. Through the forecast horizon, MECO expects an annual growth rate of 3.0% on post-DERs peak under the normal weather assumption.

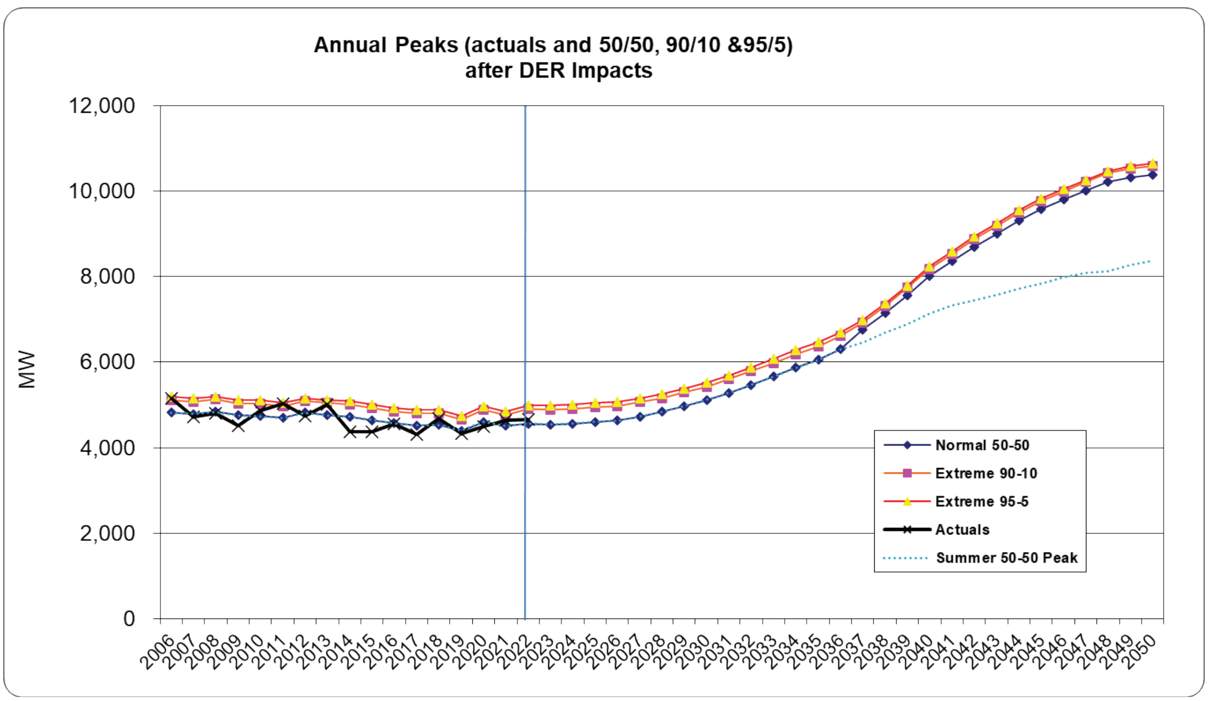

Figure 2: MECO Historical (actual & weather-adjusted) and Projected Peaks

[4] Peaks days, times and weather can vary across the zones which do not always match the same as for the Company.
[5] Managed charging is not considered in the base EV case. A managed charging scenario is considered in the low EV case.

Nantucket Electric Company (NANT)

Nantucket's peak demand in 2022 was 58.2 MW[6], on Saturday, August 6 at hour-ending 18. This set a new record for its highest historical peak.

This summer's weather for Nantucket's peak was considered much hotter than average (or 'normal'). The peak weather fell in the 76th percentile of peak weather over the last 20 years. This means that 76% of summers had peak weather that was cooler and only 14% of summers had peak weather that was warmer. This year's peak is considered 6.3 MW above the peak the company would have experienced under normal weather conditions. On a weather adjusted "normal" basis this year's peak was estimated to be 51.8 MW, an increase of 1.0% compared to last year's weather-adjusted 'normal' peak.

Nantucket's summer peak load is expected to remain to be a summer peaking system through the forecast horizon. A 1.8% annual growth rate is expected for Nantucket's post-DER peak load through the year 2050. Its peak hour is expected to shift to later of the day when EV charging demand increases, and PV saving is less available. Figure 3 shows the forecasts graphically.

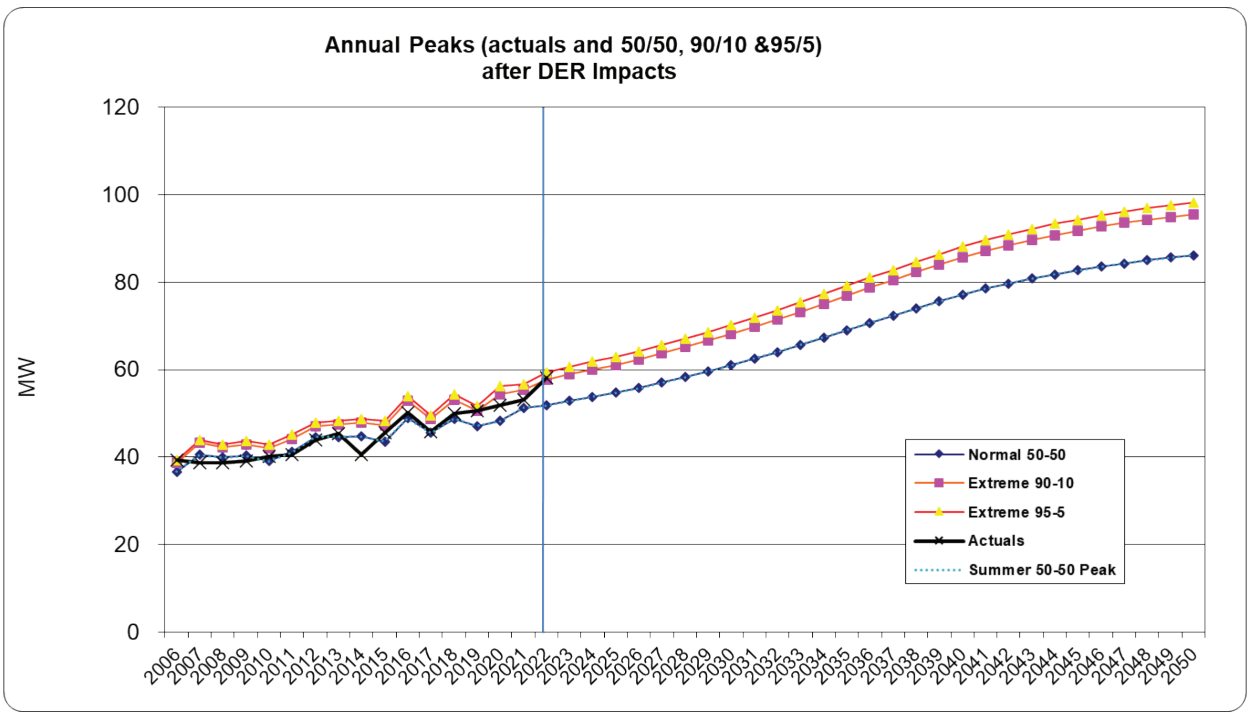

Figure 3: Nantucket Historical (actual & weather-adjusted) and Projected Peaks

[6] Meter Data Service's system level PRELIMINARY and subject to change.

Forecast Methodology

National Grid in Massachusetts forecasts its peak MW demands for the two Companies and the three ISO-NE zones that make up its service territory in the state. Each Company's total as well as the "independent" (or non-coincident) peaks for each zone are developed. The independent peak is the demand that each zone experiences, regardless of whether that demand is also the same day and time as the company's peak. The two Companies and the three zonal forecasts are:

- Massachusetts Electric Company (MECO)
- Nantucket Electric Company (Nantucket)
- Northeast Massachusetts Region: comprised of the portions of the ISO-NE load zone NEMA served by MECO; includes, among others the North shore and Merrimack areas
- Southeast Massachusetts Region: comprised of the portions of the ISO-NE load zone SEMA served by MECO and Nantucket; includes, among others, the South shore, Attleboro, Uxbridge and Fall River areas as well as Nantucket Island
- West Central Massachusetts Region: comprised of the portions of the ISO-NE load zone WCMA served by the MECO; includes, among others, the Worcester, central and western areas

The overall approach to the peak forecast is to relate (or regress) peak load to aggregate system energy. For each zone, if energy alone is not a good statistical fit (because, for instance, that zone is growing more or less than the system-level energy), then other indicators such as zonal specific economics are applied. This method allows the peak MW forecasts to grow along with energy growth rates for each zone, however, it also allows the peak to adjust to individual economic influences in each zone.

Each of these models is developed based on a "reconstructed" model of past load. That is, claimed energy efficiency, installed solar PV, demand response, and energy storage impacts are added back to the historical data set before the models are run. Electric vehicle and electric heat pump impacts are removed from the historical data set. The statistical forecasts are made based on the "reconstructed" data set. Then, the future cumulative estimates of savings or additions for these DERs are taken out or added to the statistical forecasts to arrive at the final forecast. Hourly profiles for the DERs are applied to the hourly profiles for the loads to determine the annual peaks. These final loads are also referred to as "Net" loads.

The results of this forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. Up until year 2019, distribution planning used the 95/5. The 50/50, or weather-normal scenario is used for various items including strategic scenarios and incentive mechanisms.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The relevant weather stations are Boston, Worcester, Providence, Nantucket, and Albany (due to its proximity to the western Massachusetts region). These most closely represent the Company's territory.

The weather variables used in the model include heating degree days for the colder winter months and temperature-humidity indexes (THIs)[7] for the warmer summer months. Other variables such as maximum or minimum temperature on the peak day are also evaluated. These weather variables are from the actual days that each peak occurred in each season over the historical period. Summer THI uses a weighted three-day index (WTHI)[8] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[9]. A normal distribution is assumed to derive the extreme weather scenarios.

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten-year period on average.
- Extreme 95/5 weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty-year period on average.

These "normal" and "extremes" are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Figures 4 and 5 show the historical, weather-normal, and weather-extreme WTHI values for MECO and Nantucket, respectively.

[7] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[8] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[9] Normal distribution is assumed to derive the extreme weather scenarios. This "probabilistic" approach employs "Z-values" and standard deviations to calculate the extreme weather scenarios. As a result, the more spread out the numbers on peak days over the historical period, the more the 90/10 and 95/5 values will be above the mean (or the normal).

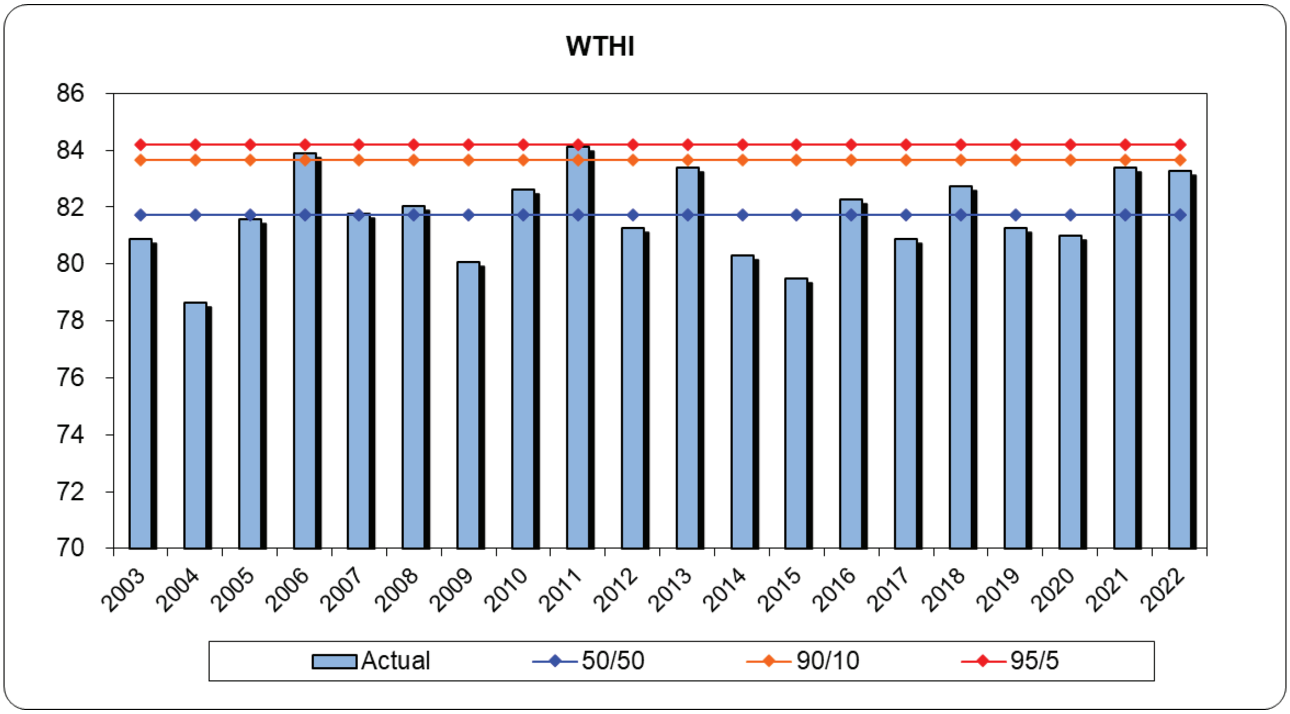

Figure 4: Actual, normal and extreme WTHI for MECO

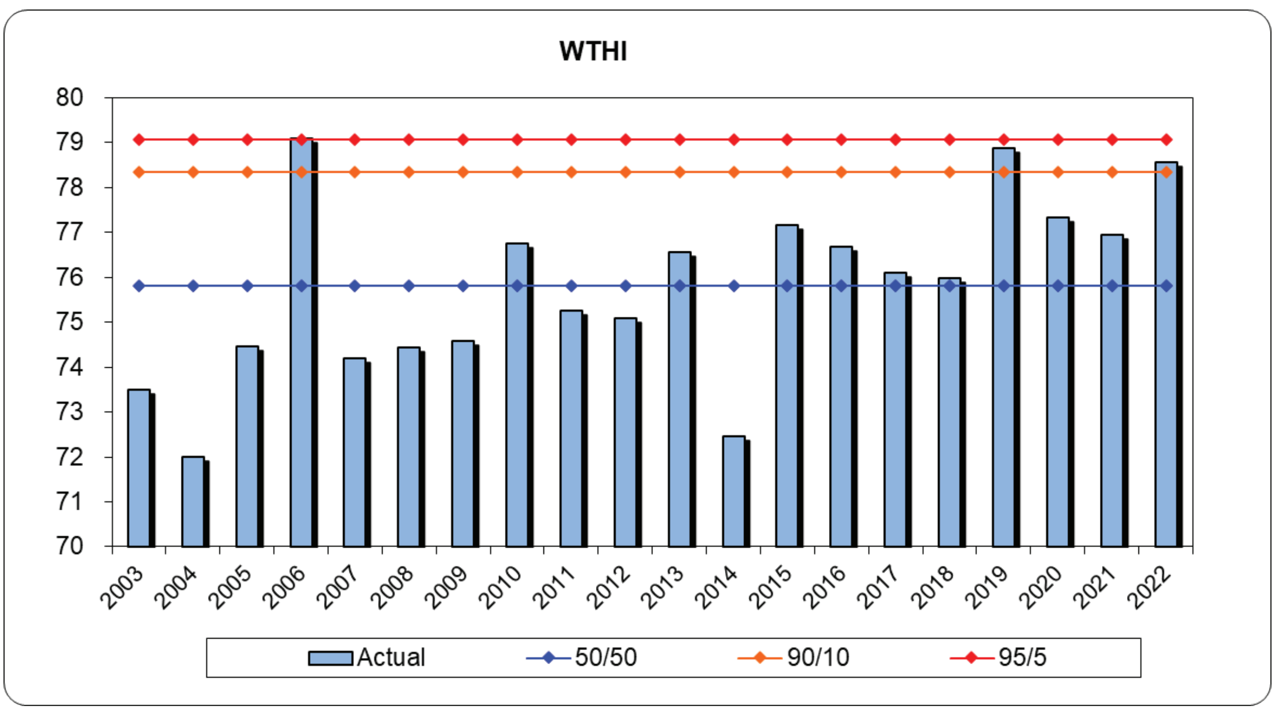

Figure 5: Actual, normal and extreme WTHI for Nantucket

Distributed Energy Resources (DERs)

In New England, there are policies, programs, and technologies that impact customer loads. These include but are not limited to energy efficiency (EE), solar photovoltaics (PV), electric vehicles (EV), demand response (DR), electric heat pumps (EH), and energy storage (ES). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

A base case forecast is developed for each of the DERs and is part of the official forecast. For each of the DERs, a higher case and a lower case than the base case are developed, as appropriate. The inclusion of multiple cases for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions. The discussion below is based on the base case.

Figure 6 shows MECO's forecasted annual peak load. The annual peak is expected to occur in the summer between 2023 and 2035. The peak hour will shift from late afternoon to the evening hours. The reconstituted (pre-DER) load is generally lower in the evening than the afternoon, resulting in a decrease in the pre-DER load. Figure 6 shows a drop in year 2024 and year 2027 in the reconstituted load, when the peak hour shifts to later of the evening. After the DER impacts, MECO's peak is forecasted to grow, 2.2% per year on average through 2035. Starting in 2036, MECO's winter peak is expected to become the annual peak mainly driven by the increasing load from electric heating and electric vehicle charging. This shows as a step-down of pre-DER load from 2035 to 2036. However, the post-DER load is forecasted to grow through the end of the forecast horizon.

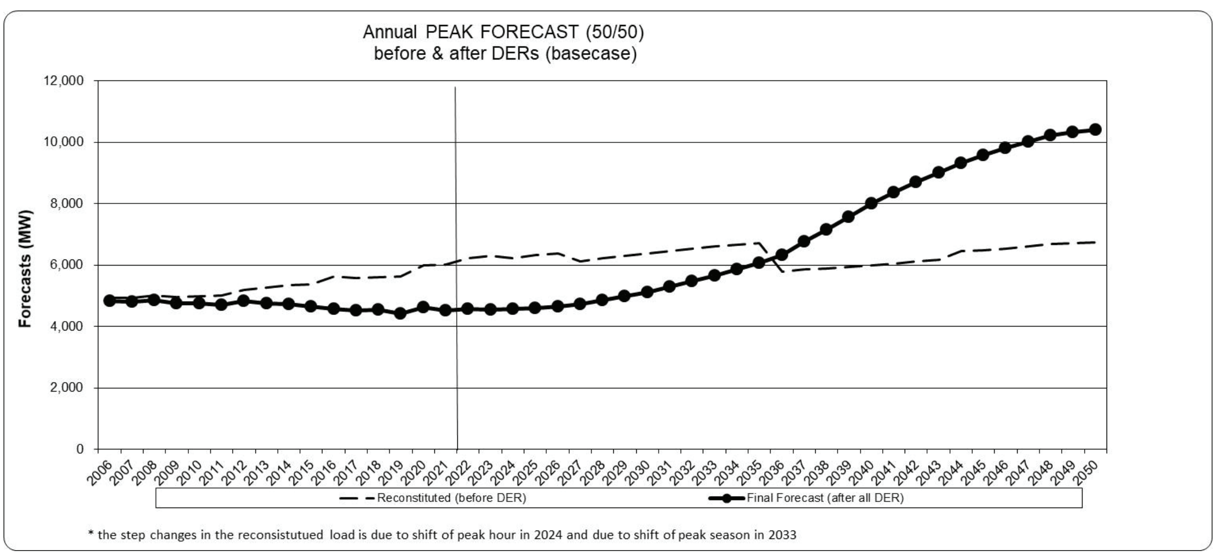

Figure 6: Annual loads before and after the impacts of DERs for MECO

Figure 7 shows the impacts for the DERs each year. The peak hour is expected to shift from hour-ending 18 to hour-ending 19 in 2024 and then to hour-ending 21 in 2027, lower or no PV impact is expected as less or no irradiation is available at this later hour. The EV and electric heat pump impacts grow faster in later years of the forecast horizon, which leads to a winter peak starting 2036 when the total net DER impacts become positive (i.e., adding load).

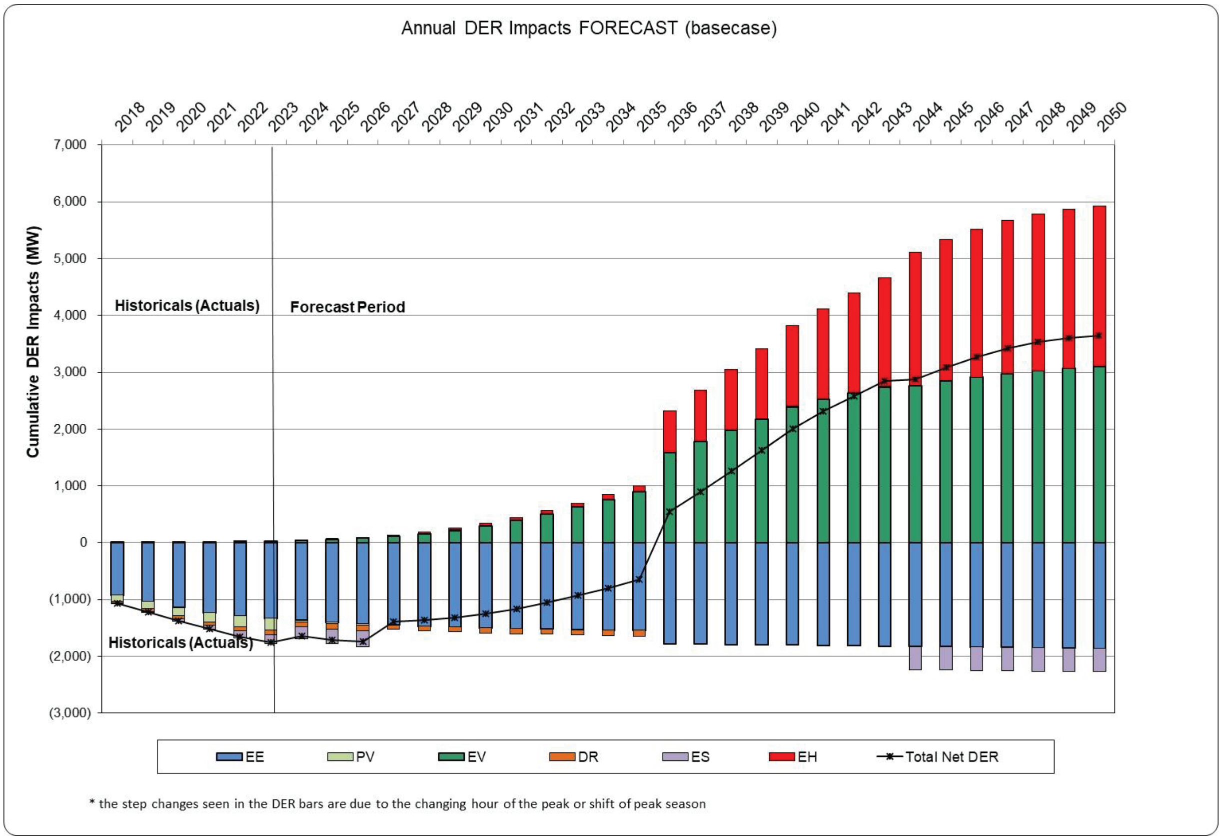

Figure 7: Annual Impact of DERs for MECO

Figure 8 shows Nantucket's expected loads and impacts for the DERs each year. The net DER impact is expected to decline with increasing adoptions of EVs and electric heat pumps.

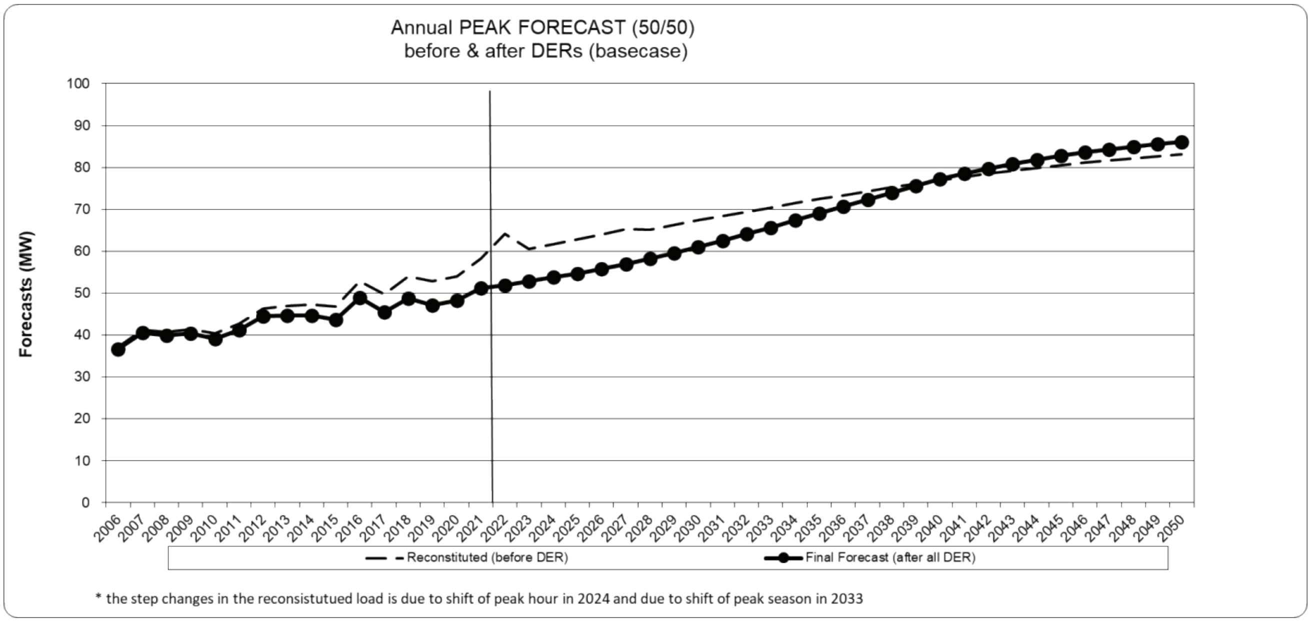

Figure 8: Annual loads before and after the impacts of DERs for Nantucket

Figure 9 shows the impacts for the DERs each year. The summer peak hour is also projected to shift to later of the day, when the PV saving is less.

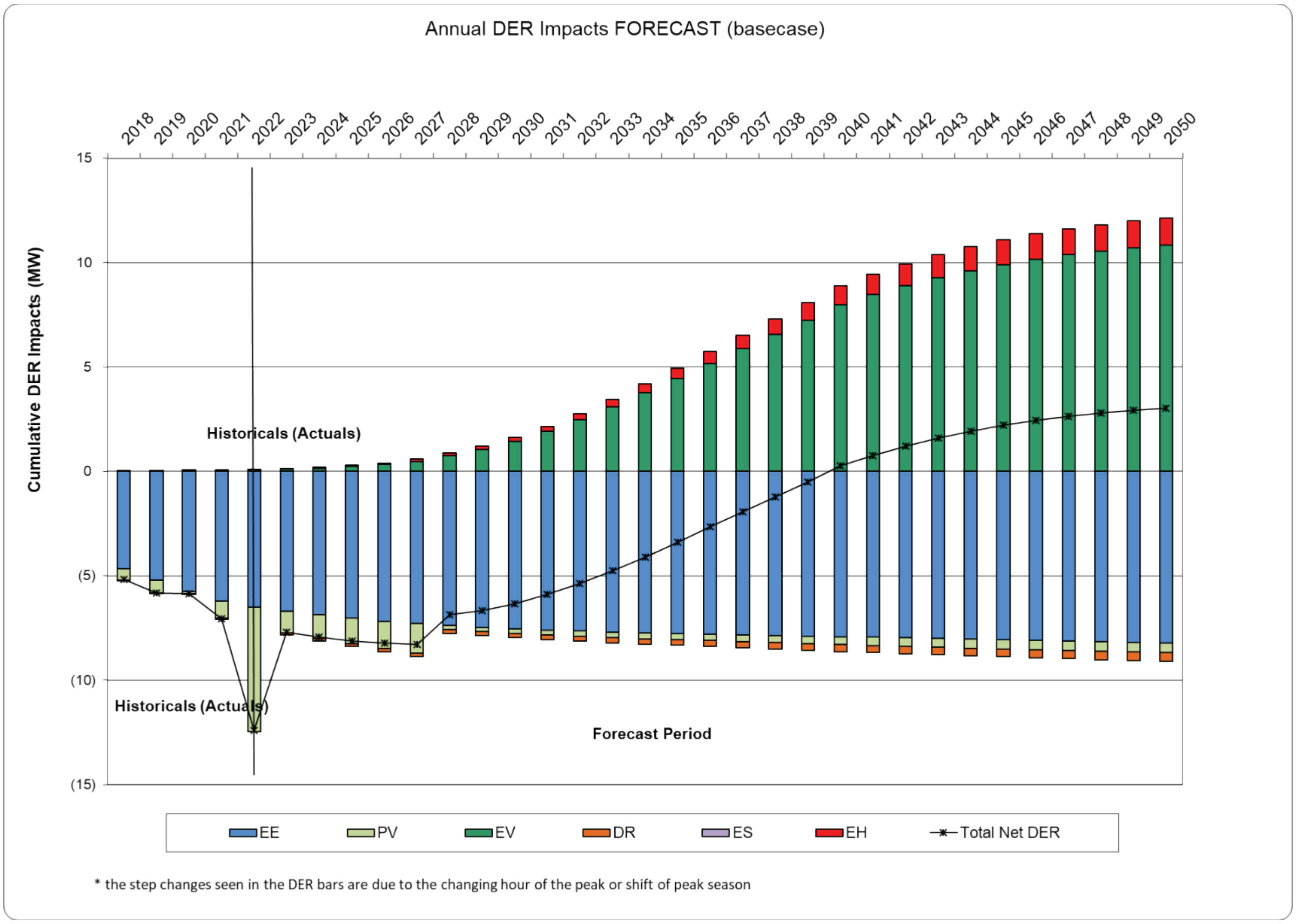

Figure 9: Annual Impact of DERs for Nantucket

Each of the DERs is discussed next.

Energy Efficiency (EE)

National Grid has had EE programs in its Massachusetts jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term (one to three years), EE targets are based on Company annual plan from the Subject Matter Experts (SMEs) through 2024. Beyond 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year.

For MECO, as of 2022, compared to the counterfactual with no EE programs, it is estimated that these EE programs have reduced the summer peak load, which is also the annual peak load, by 1,292 MW, or 20.8% of what load would have been had these programs not been implemented. By 2050, it is expected that this reduction to the summer peak will grow to 1,633 MW or 21.1%. For winter peak load, as of 2021, it is estimated that these EE programs have reduced the winter peak load by 1,496 MW or 29.6% and are expected to grow to 1862 MW of 27.6% by 2050.

For Nantucket, as of 2022, compared to the counterfactual with no EE programs, it is estimated that these EE programs have reduced the load by 6 MW, or 11.0% of what load would have been had these programs not been implemented. The EE impacts will continue to grow to 8 MW, or 9.9% of the gross load by the year 2050.
Figure 10 &11 present the annual incremental (left-axis) and cumulative (right-axis) summer EE MW and winter EE MW for National Grid's Massachusetts jurisdiction, respectively. The value is allocated to MECO and Nantucket based on their load shares in the jurisdiction.

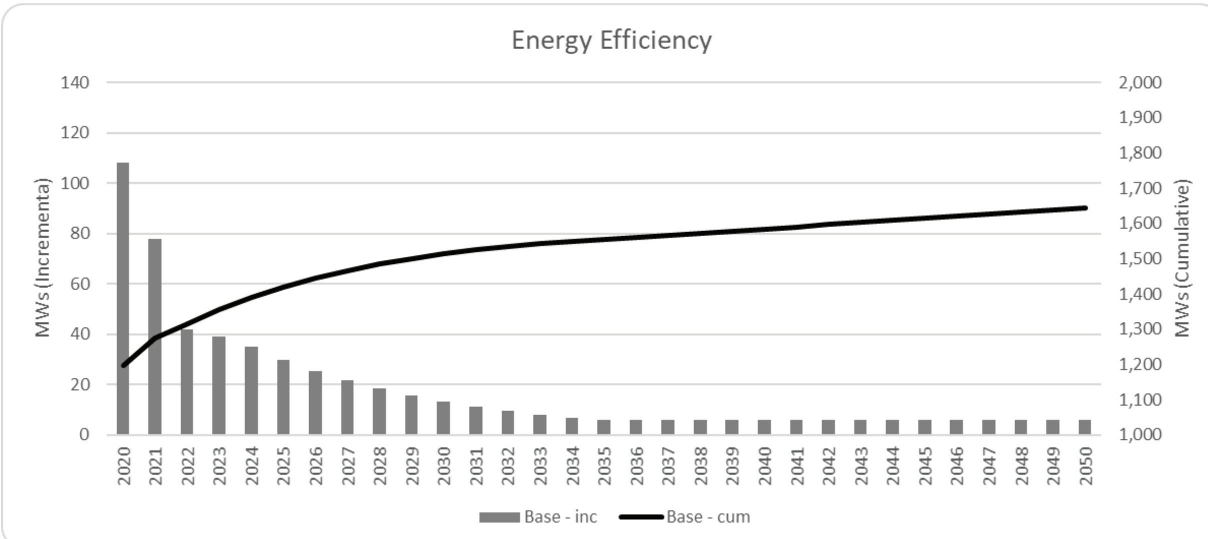

Figure 10: Energy Efficiency summer MW by year

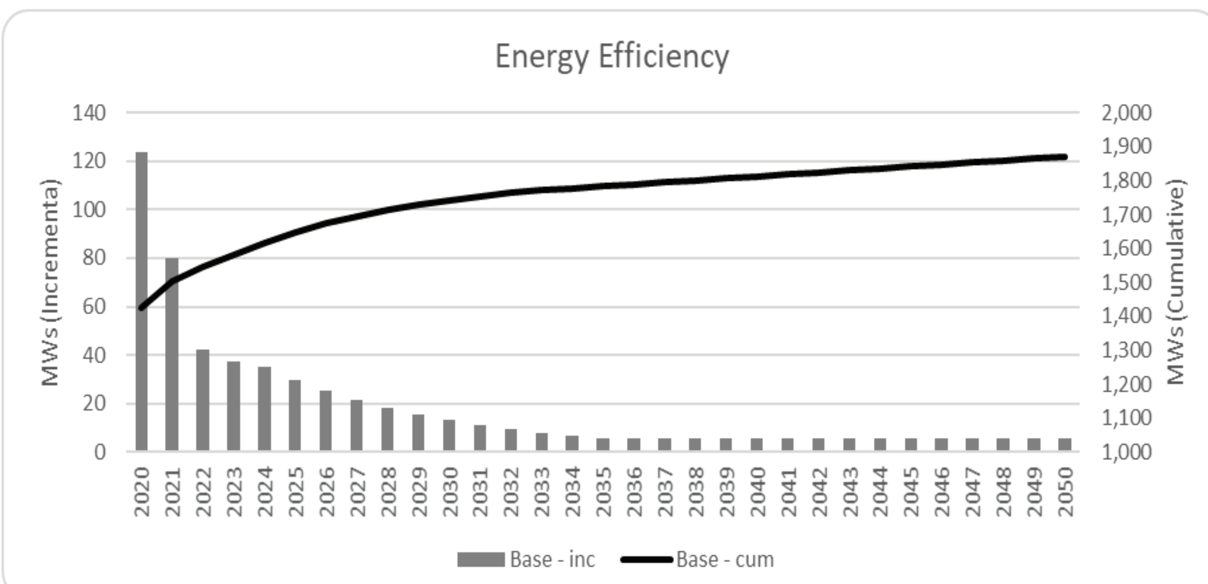

Figure 11: Energy Efficiency winter MW by year

Solar-Photovoltaic (PV)[10]

There has been a rapid increase in the adoption of PV throughout the state. The actual installed PV is tracked by the Company and used for the historical values. The near-term (2023-2027) predictions leveraged the information on the projects in the Company's queue and the insights from PV subject matter experts at the Company, and also assumes National Grid fills its share (45%[11]) of the State's existing solar standards of 3.2 GW[12] by mid 2020s. In the longer-term, continuous growth is projected in order to achieve the National Grid's share (45%) of the State policy target under the All Options scenario as stated in its 2050 decarbonization roadmap[13]. The All Options scenario targets a 6.99 GW of behind-the-meter (BTM) PV connection and a 16.2 GW of ground-mounted PV connection by 2050 for the State of Massachusetts. In this base case, it is assumed that all the BTM PV and 50% of the ground-mounted PV will be on the distribution system. It is then assumed that the Company will take its share of these. Thus, about 3.1 GW (6.9 GW * 100% * 45%) of BTM PV and 3.6 GW (16.2 GW * 50% * 45%) of ground-mounted PV are projected to be on the Company's distribution system by 2050.

Figure 12 shows the projected incremental (left-axis) and cumulative (right-axis) connected PV installations of National Grid's Massachusetts jurisdiction. The value is allocated to MECO and Nantucket based on their load shares in the jurisdiction. As of 2022, it is estimated about 1,745 MW will have been connected, growing to almost 6,716 MW by 2050.

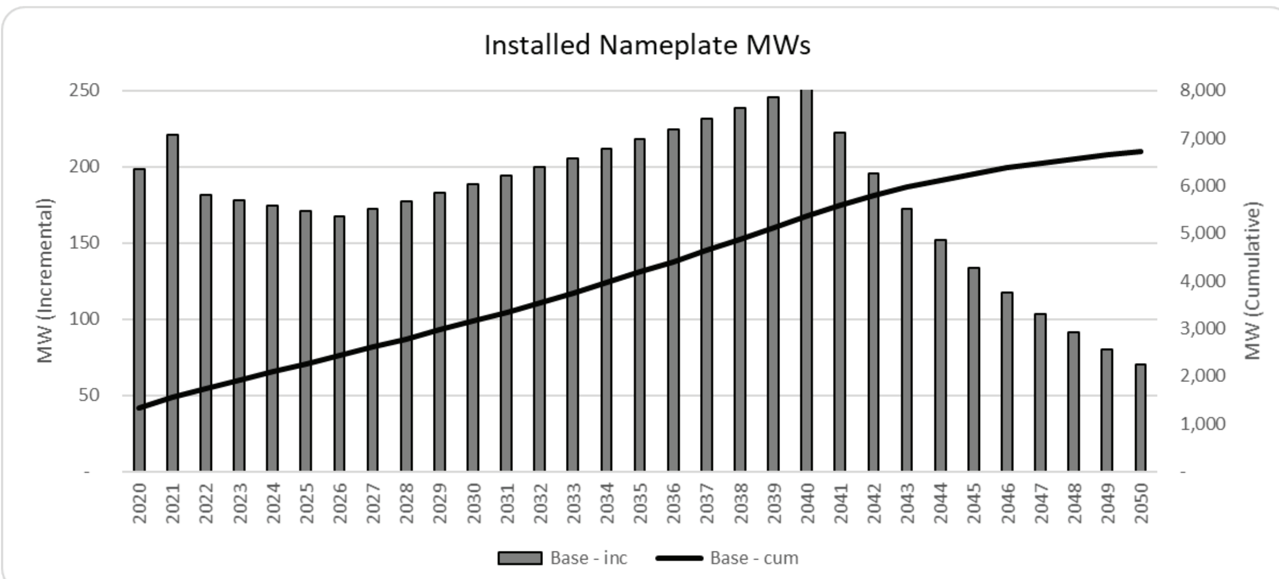

Figure 12: Solar-PV connected nameplate (AC) MW by year

While installed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less daylight. For MECO, its winter peak is expected to

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[10] This discussion is limited to PV which expected to reduce loads and would not include those PV installations considered as 'supply' by the ISO-NE. This can include both 'behind-the-meter" and in "front-of-the-meter" for those installations like community solar which are allocated back to customers.

[11] 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the State of Massachusetts compared with Eversource and Unitil. This same share is assumed for calculating National Grid share of the State's existing and planned solar goals.

[12] *MA Clean Energy and Climate Plan for 2030*, page 68, June 2022.

[13] *Massachusetts 2050 Decarbonization Roadmap*, December 2020

exceed the summer peak and become the annual peak in later years – 2036 through 2050, PV saving is not available or much less available during the projected winter peak hour.

Electric Vehicles (EV)

EVs increase peak load over time. The EVs considered are those that plug-in to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that have impacts on the electric network. In addition to light-duty EVs that the Company has been tracking and considering in its electric load forecasts, this year, the Company expand the scope from light-duty EVs only to include light-duty, medium-duty, heavy-duty EVs and electric buses, and consider the EV adoptions of BEVs and PHEVs in these four different vehicle types.

The light-duty EV base case is developed around California's Advanced Clean Car II (ACC-II)[14] rules, which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of light-duty vehicle (LDV) sales is created based on the techno-economic potential and current market trends. In the medium-term (2026-2030), the ACC-II rules have a range of possible outcomes, so the zero-emission vehicle sales share rises in line with the "flexibilities[15]" (or lower-bound) of what the ACC-II rules require, reaching 59.5% in 2030. In the longer term (2031 and onward), zero emission vehicle sales match the ACC-II rules and reach 100% zero emissions vehicles in 2035 (and assume no more than 20% plug-in hybrid electric vehicles). Vehicle scrap is assumed based upon market data to develop the net EV in-operation numbers. The adoptions of medium-duty EV (MDEV) and heavy-duty EV (HDEV) and E-buses are based on the California's Advanced Clean Trucks (ACT)[16] rules through 2035 which have been adopted by the state. In the base case, the sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035. To extend the forecast until 2050, a similar growth rate is considered from 2036 to 2040, and after that 3% growth in sales share is assumed through 2050. That leads to 100%, 80%, and 100% sales shares for MDEV, HDEV, and E-Buses by the end of the forecast horizon, respectively.

Figure 13 shows the historical and estimated number of EVs in the National Grid's Massachusetts jurisdiction. As of the end of 2022, it is estimated that about 32,000 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in MECO's service territory, growing to about 2,655,000 by the end of the forecast horizon.

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[14] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii, retrieved September 2022

[15] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

[16] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks, retrieved September 2022

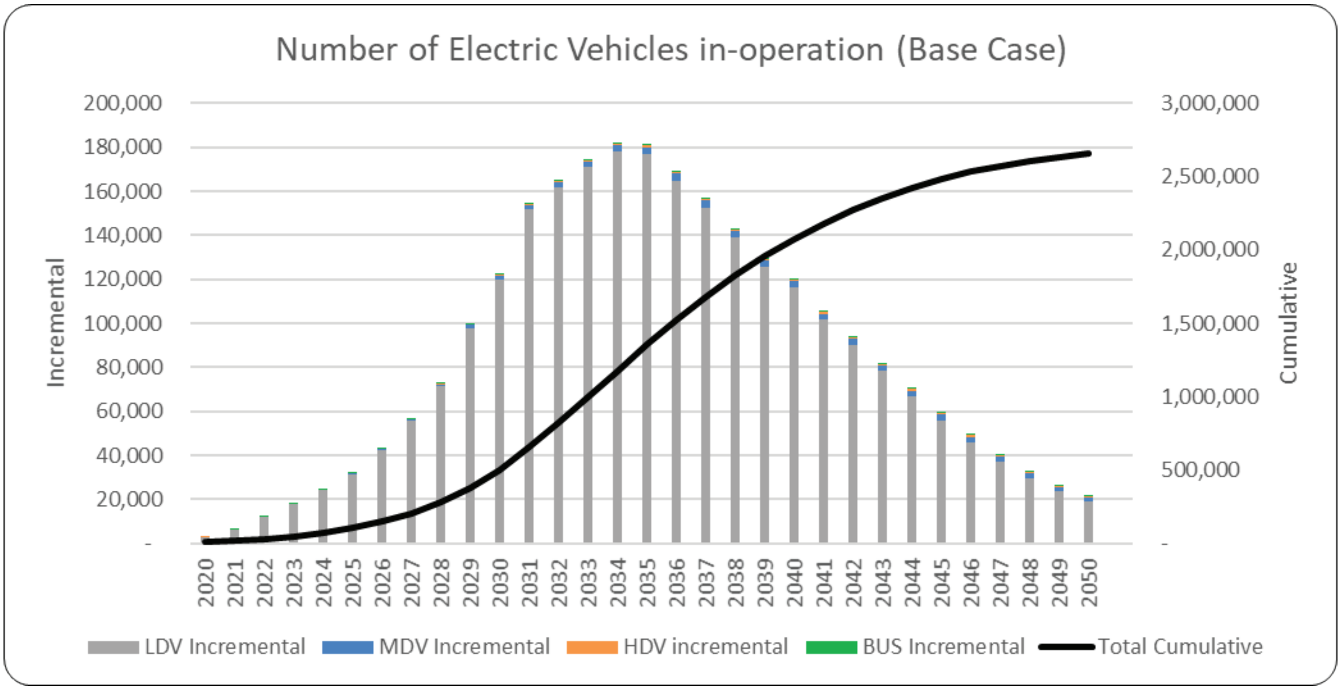

Figure 13: Number of Incremental and Cumulative EVs in National Grid's Massachusetts Service Territory

EV charging impacts are estimated for light-duty, medium-duty, heavy-duty, and electric buses separately, and vary by different season of the year too. In general, EV charging load is higher during cold weather seasons. Managed charging is not considered yet in base EV case but a managed charging scenario is provided in the low EV case to offer a view on how managed charging may impact the load. It is estimated that these electric vehicles may have increased MECO's cumulative summer peak loads by about 11.8 MW as of 2022, increasing to about 2,176 MW of cumulative summer peak load increase in the year 2050. For winter peak loads, its impact is estimated to be 11.1 MW as of 2021, increasing to about 3,099 of cumulative winter peak load increase in the year 2050. For Nantucket, the increase of summer peak load is negligible as of 2022 but is expected to grow to 10.9 MW by 2050. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[17] electrification.

Electric Heat Pumps (EH)

The base case is based on the Company's heat pump targets through 2024. Post 2024, the Company assumes that Company's pro rata shares of CECP phased pathway's target in 2050[18] will be met. Thus, about 1.34 million of units will be installed by 2050 and about 80% of those will be installed as full applications. A full application is defined as a heat pump unit that will serve the all the heating and cooling in the home or building. A partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season. Penetration rates are expected to be about 86% of residential homes and 58% of commercial space heating capacity by 2050.

[17] Beneficial electrification is based on an overall portfolio of lowered carbon emissions from the transportation sector coupled with lower/carbon free generation of electricity in the power sector to support the charging of the EVs.
[18] *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, June 2022

Figure 14 shows the projected heat pump adoptions through the forecast horizon.

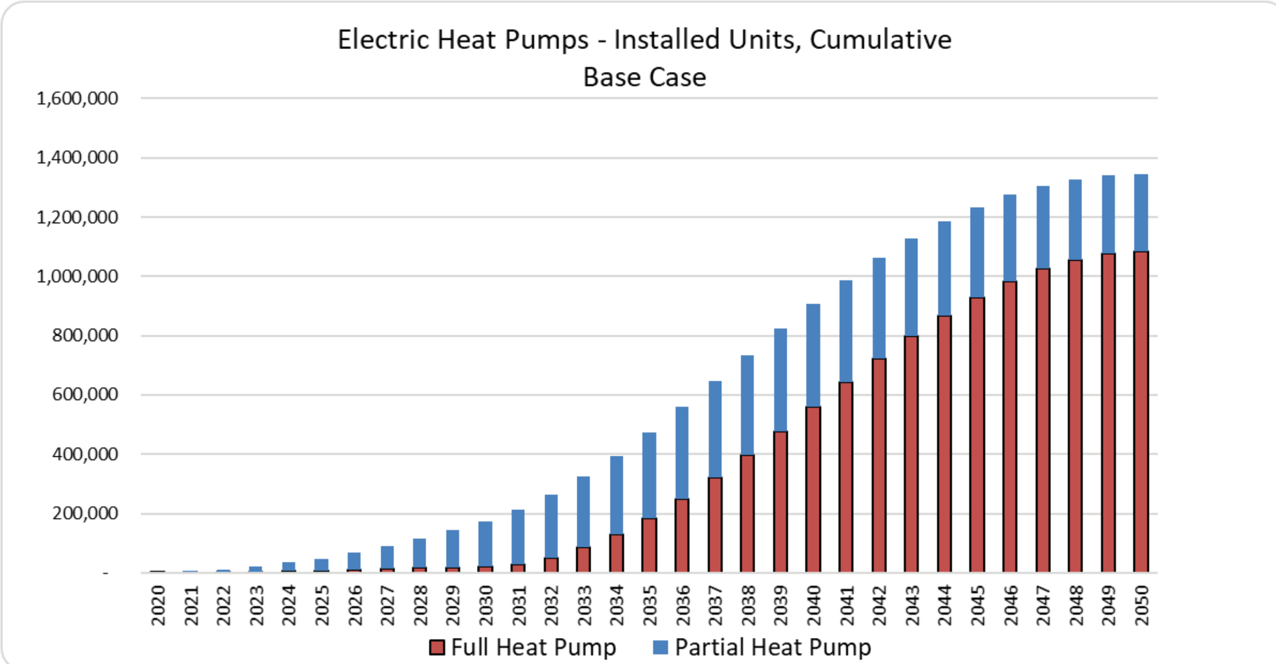

Figure 14: Cumulative Number of Electric Heat Pumps

<u>Demand Response (DR)</u>

DR programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These resources must be dispatched, unlike the more passive energy efficiency programs that provide savings throughout the year. The DR programs enable utilities and operating areas, such as the New England Independent System Operator (ISO-NE) to act in response to a system reliability concern or economic (pricing) signal. During these events, customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

In general, there are two categories of Demand Response programs in Massachusetts. These are ISO-NE programs and Company retail level programs.

The ISO-NE programs, referred here as "wholesale DR", have been active for several years and were periodically activated. There were no ISO-NE DR events this year, and there has not been one since 2016. The company's policy has been to add-back reductions from these DR events to its reported system peak numbers. This is because the Company is not in control of the dispatch days or times and thus there is no guarantee that these ISO-NE events would be at the times of company peaks. Therefore, the Company must plan to assume they are not dispatched.

The Company recently began to run its own DR program at the retail customer level. In contrast to the wholesale level DR programs implemented by the ISO-NE, these programs are activated by the Company. The company counts the impact of DR resources enrolled in the retail program as load reductions.

In 2022, for MECO, the estimated impact on summer peak was 101 MW (in the retail program only) and is expected to grow to about 222 MW the year 2050. The hours of dispatch for DR are assumed to move over time to capture the hours of the peak, however, as the hours of the peak move outside of normal commercial sector activity, it is expected that DR impacts would be harder or impossible to achieve during peak hour(s). No DR program is expected for winter at this point.

Energy Storage (ES)

For the base case targets, it is assumed that the Company would make a share of the statewide energy storage policy goals. In Massachusetts, the state policy is 1000 MWh by 2025[19]. For summer peak impacts this is first converted to a MW equivalent using a four to one charging to peak output factor. Thus, the 1000 MWh target is about 250 MW. Only a portion of these is at the distribution level and will lower the load forecast (the remainder being considered supply by the ISO-NE and not considered in this load forecast). Based on the amount of energy storage installed in the state as of 2021, about 37% is considered distribution level and thus load reducing. Based on this the storage targets considered load reducing are lowered to 92.5 MWs (37% * 250) by year 2025. The Company's share of storage as in the state as of this year is about 78%. This is assumed to persist through year 2025. Thus, it is assumed that the year 2025 target for the Company is 72.15 MW (78% * 150). Not all energy storage will help to reduce the Company's summer peaks. A number of customers may use their storage to serve their own needs and times. It is assumed that only 85% of the installed energy storage amounts will impact the peak load. Thus, the final year 2025 target for peak reducing storage is 61.3 MW (85% * 102).

Massachusetts does not currently have explicit energy storage targets beyond year 2025. However, the State has published two studies, one the Clean Energy and Climate Plan for 2030 (CECP) and two the "Energy Pathways to Deep Decarbonization 2050". In the 2050 document, there are several scenarios that can guide the state to meeting its year 2050 long-term Climate goals. For example, by the year 2050, the "All options" scenario implies about 3,000 MW of large-scale energy storage (generation), "100% Renewable" scenario implies about 4,000 MW and the "No thermal" scenario implies 12,000 MW[20]. The Company used those inferred long-run energy storage capacity to provide a context to its long-term forecast at the distribution level. In order to do that, the company made two assumptions in the long run: (a) the company 'share of energy storage in the state will approximate the company's load share in the state (45%) and (b) more energy storage will move towards the supply side and less new storage as distribution level load reductions. The longer-term distribution share is assumed to drop to 20% (vs. 37% now). By using these assumptions, the current company's long term energy storage installed capacity forecast in 2050 will relate to the different pathways from "Energy Pathways to Deep Decarbonization 2050 as follows: the base case forecast of 516 MW will be between "All Options" and "100% renewable" scenarios. Finally, it is assumed the long-term peak reducing estimate will remain at 85% (85% is based on similar findings in New York which have significant pricing signals during peak hours). For the base case scenario, this lowers the final target to 439 MW by year 2050 (85% * 516).

The actual projections for installed energy storage are as follows. As of the end of year 2021 there was about 111 MW installed in the Company's service territory, about 58 MW of which was installed in

[19] https://www.mass.gov/info-details/esi-goals-storage-target, retrieved November 2022

[20] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*, page 61, December 2020

the year 2021 alone. The base case assumes a continuation of this 58 MW per for the next three years, before assuming some saturation. Saturation is assumed to be 20% less per year for each subsequent year forward. This puts the Company on a path to easily surpass both the year 2025 and year 2050 targets determined above. Thus, it can be said that the Company is on-target for the CECP 2030 goals for this DER.

All prior discussion on load & DERs above is limited to the base case. Additional higher and lower scenarios are provided later in this section (see 'DER scenarios') and in the Appendices.

Peak Day 24 Hourly Curves

While the single peak values discussed so far are of major importance, the estimated impacts due to DERs on an hourly basis on these peak days is also important. For the two companies and for each of the zones, a 24-hour peak day load profile is provided. This allows the companies to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process now looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. And as more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 16 shows the "24 hour" peak summer day for selected years over the planning horizon for the base case DERs for MECO. "Gross" refers to loads before DER impacts and "Net' refers to loads after DER. The selected years are 2022, 2027, 2032, 2040, and 2050. The figure clearly shows how the expected DERs lower the load during middle of the day and add load from electrifications, which leads to the shift of the peak hour from afternoon to evening and night. Figure 17 shows the impact of the "24 hour" peak summer day under the DER scenario of managed light-duty electric vehicle charging and base cases for all other DER technologies. Under this scenario, the EV charging load is shifted from traditional peak hours of afternoon and early evening to late of the night, and the magnitude of the peak load is also lower than the scenario that EV charging is unmanaged.

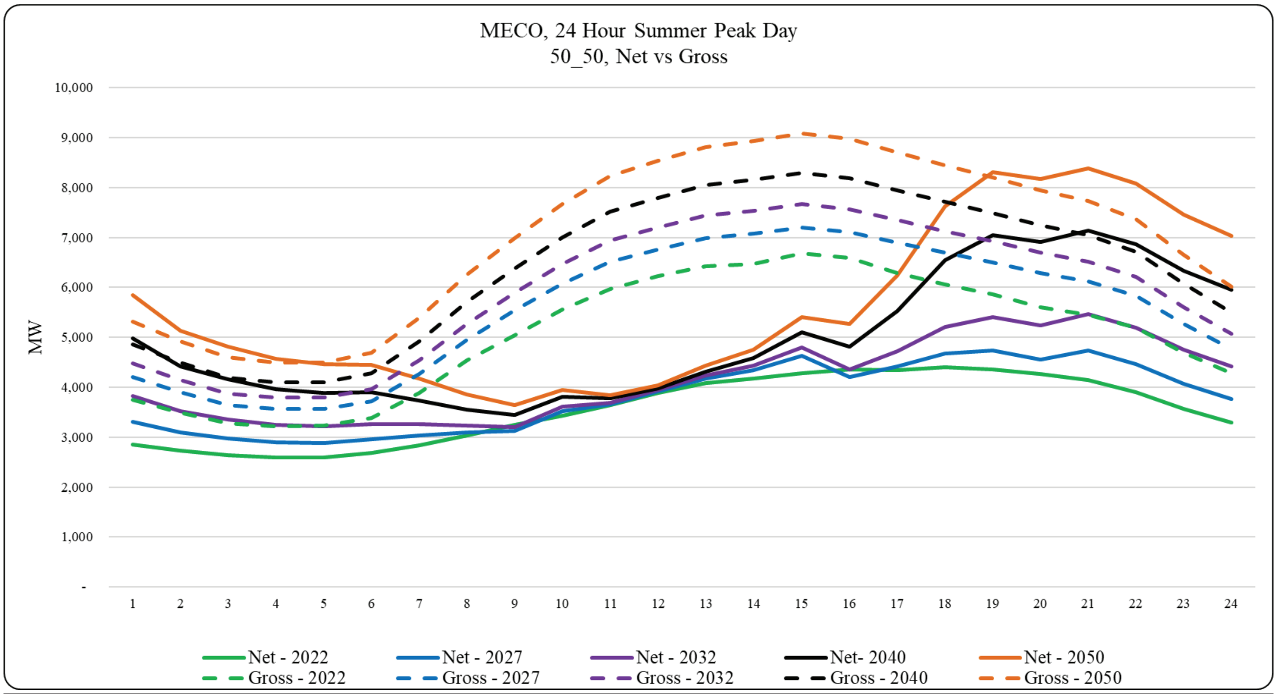

Figure 16: Peak Summer day hourly load, pre and post DERs for MECO

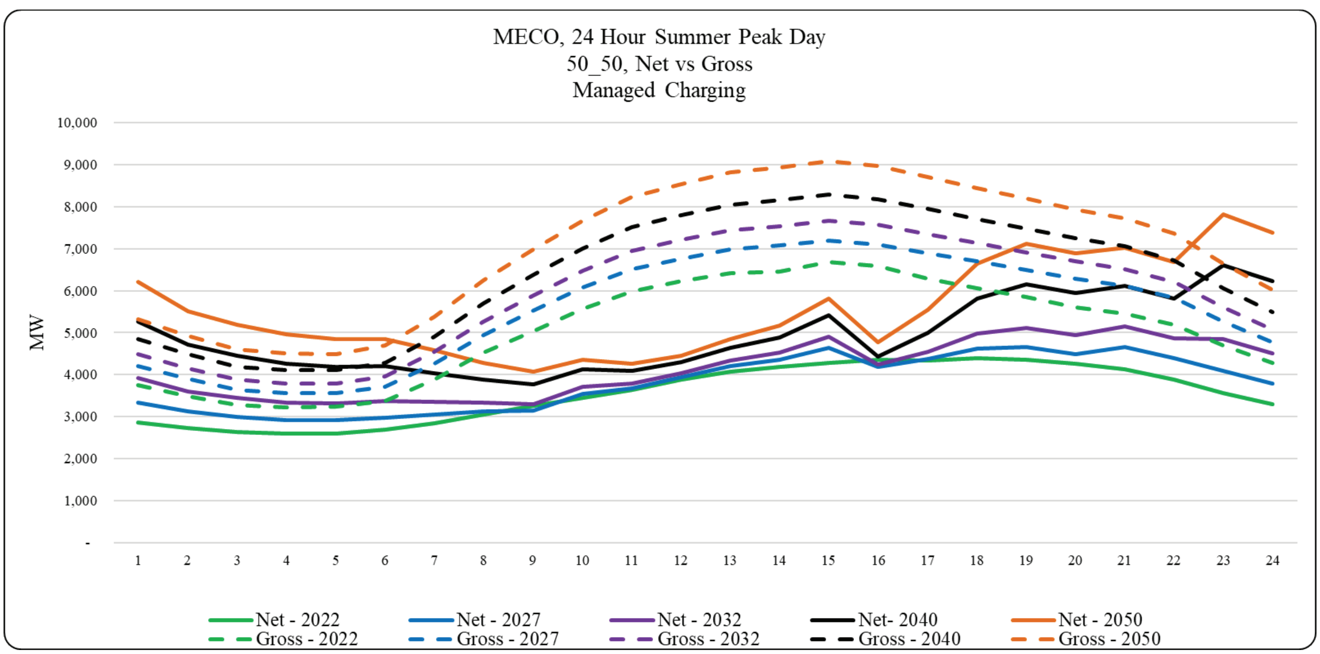

Figure 17: Peak Summer day hourly load, pre and post DERs for MECO under managed light-duty electric vehicle charging scenario

Figure 18 shows the “24 hour” peak winter day for selected years over the planning horizon with the base case DERs. The selected years are 2021, 2026, 2031, 2040 and 2050. The figure shows the dual peaks associated with winter days. The morning and evening/night load quicky ramp-up from the demand of EV charging, and electric heating, as well as the savings from PV becoming less available or unavailable during peak hours. Figure 19 shows the impact of the “24 hour” peak winter day under the DER scenario of managed light-duty electric vehicle charging and base cases for all other DER technologies. Under this scenario, the EV charging load is shifted from traditional peak hours of early evening to late of the night, and the magnitude of the peak load is also lower than the scenario that EV charging is unmanaged. The load of other hours are pushed higher with charging load being shifted to those hours.

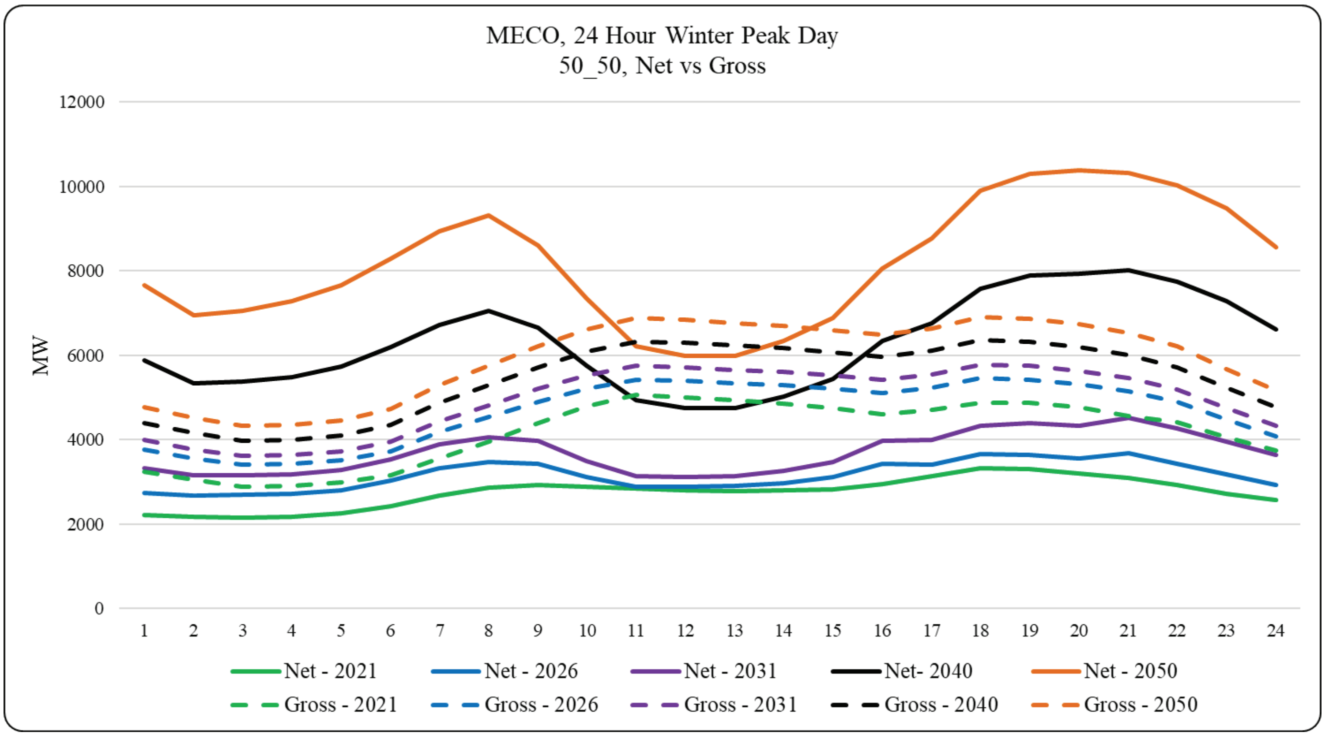

Figure 18: Peak Winter day hourly load, pre and post DERs for MECO

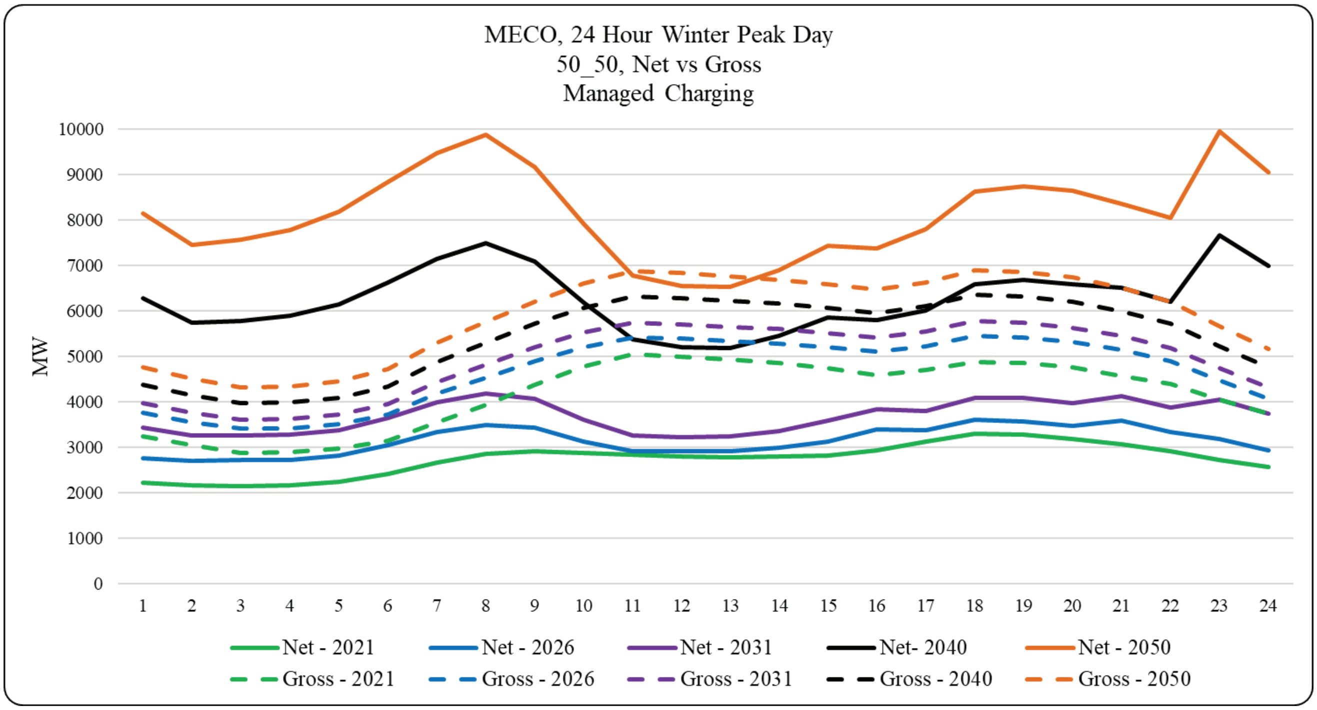

Figure 19: Peak Winter day hourly load, pre and post DERs for MECO under managed light-duty electric vehicle charging scenario

Appendix E contains additional load shapes for other day types including summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is no weekday business load.

DER Scenarios

The body of this report thus far has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV, DR, ES, EH) also has a higher-case and a lower-case scenario, as appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[21].

Each of the various combinations of DERs scenarios – base, high and low – were modeled. This creates thousands of combinations. In order to assess the probabilities of any one of these scenarios occurring, each DER technology was assigned a 'probability' level. For example, for the three EE cases, these were assigned 60% likelihood for the base case, 5% for the high case and 35% for the low case. These assignments are based on group consensus with the SMEs for the DER and sum to 100%. This process is repeated for each DER. Table 1 shows the probabilities used in the forecast.

Table 1: Probabilities for each DER case

MA	Low	Base	High
Energy Efficiency	35%	60%	5%
Solar - PV	20%	75%	5%
Electric Vehicles	15%	70%	15%
Demand Response	5%	85%	10%
Energy Storage	10%	80%	10%
Electric Heat Pumps	20%	75%	5%

Figure 20 & 21 shows summer and winter net load under selected DER scenarios – base case (which is the most likely) is blue solid line and the maximum and minimum cases are red solid lines which provide the highest and lowest bounds for planning purposes The base is the scenario with base cases from all DER technologies. The maximum load scenario / minimum DER saving scenario is the scenario with high cases for energy efficiency, solar PV, demand response, and energy storage; and low cases for electric vehicles and electric heat pumps. The minimum load scenario / maximum DER saving scenario is the scenario with low cases for energy efficiency, solar PV, demand response, and energy storage; and high cases for electric vehicles and electric heat pumps. It also shows the other more likely cases besides the base case, and they are shown as black dashed lines.

[21] In this forecast, six DERs, each with three cases – base, higher and lower, creates 729 cases (3^6) for each weather scenario. With three weather scenarios 2,187 scenarios are generated for the Company and the same for each individual zone.

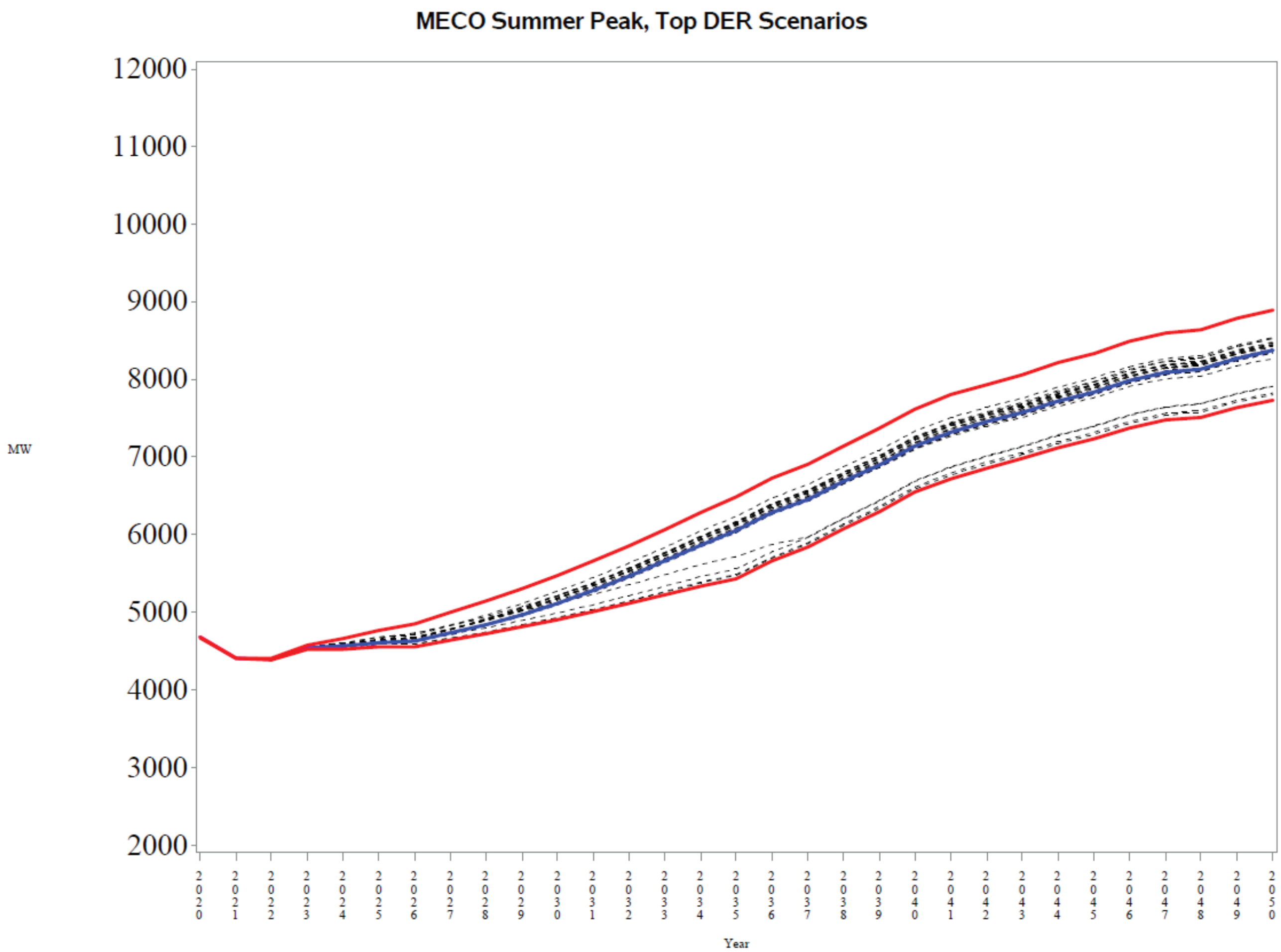

Figure 20: MECO Summer Peaks (50/50), NET, selected DER scenarios

Figure 20 shows that the summer peak load five years from now or in year 2027, ranges from about 4,641 MW to 5,004 MW - a 363 MW spread, with the base case at 4,732 MW. The uncertainty increases over time, so that by year 2050, the range expands to from about 7,732 MW to 8,891 MW, or almost a 1,158 MW spread, with the base case at 8,377 MW.

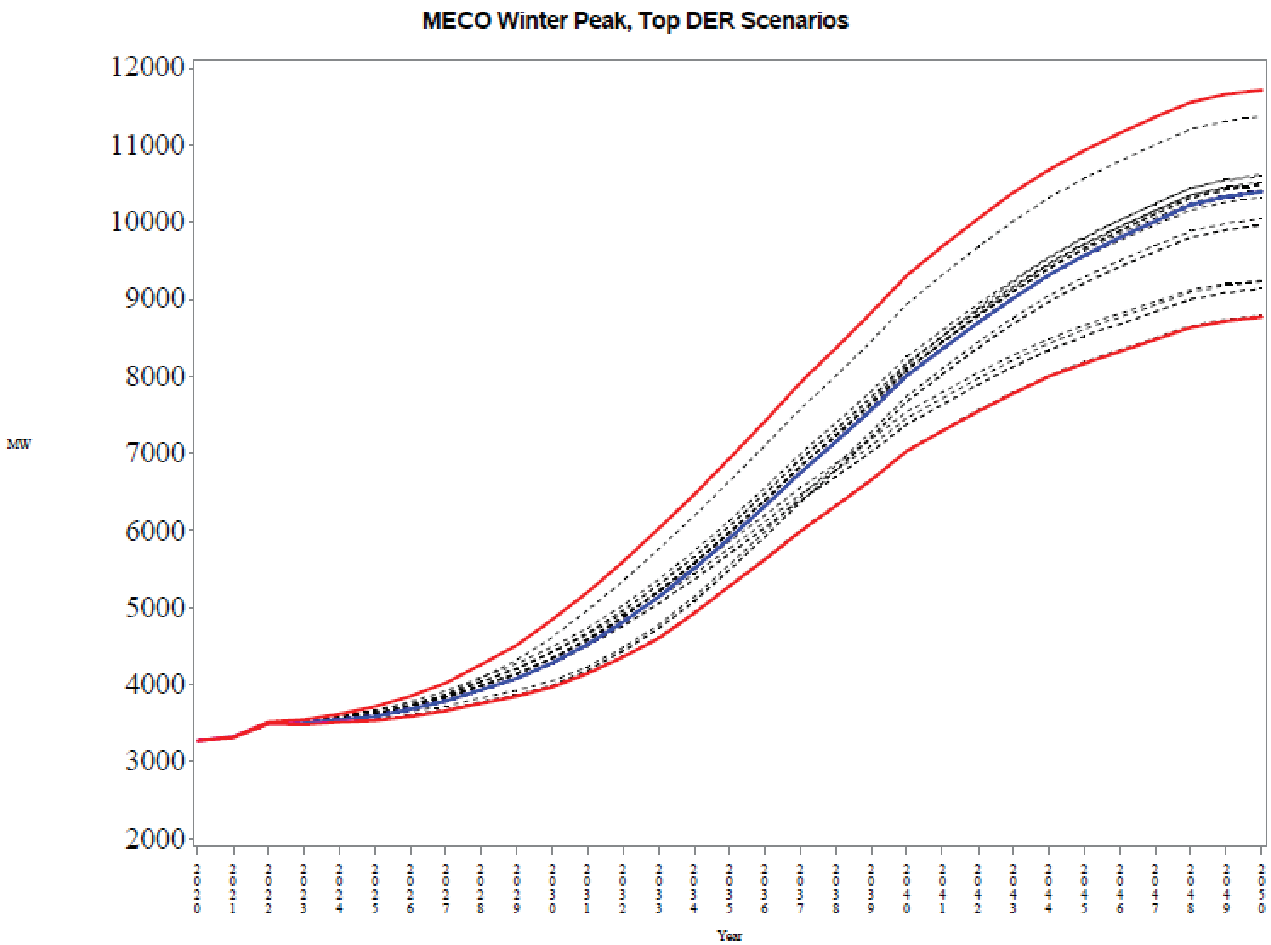

Figure 21: MECO Winter Peaks (50/50), NET, selected DER scenarios

Figure 21 shows that the winter peak load five years from the most recent winter or in year 2026, ranges from about 3,585 MW to 3,846 MW - a 261 MW spread, with the base case at 3,677 MW. The uncertainty increases over time, so that by the year 2050, the range expands to from about 8,769 MW to 11,711 MW, or almost a 2,942 MW spread, with the base case at 10,389 MW.

It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are very, very unlikely.

While Figure 20 & 21 above show what the longer-term annual summer peaks and winter peaks look like, Figures 22, 23, 24, and 25 show what the 24-hour peak day profiles might be for selected years.

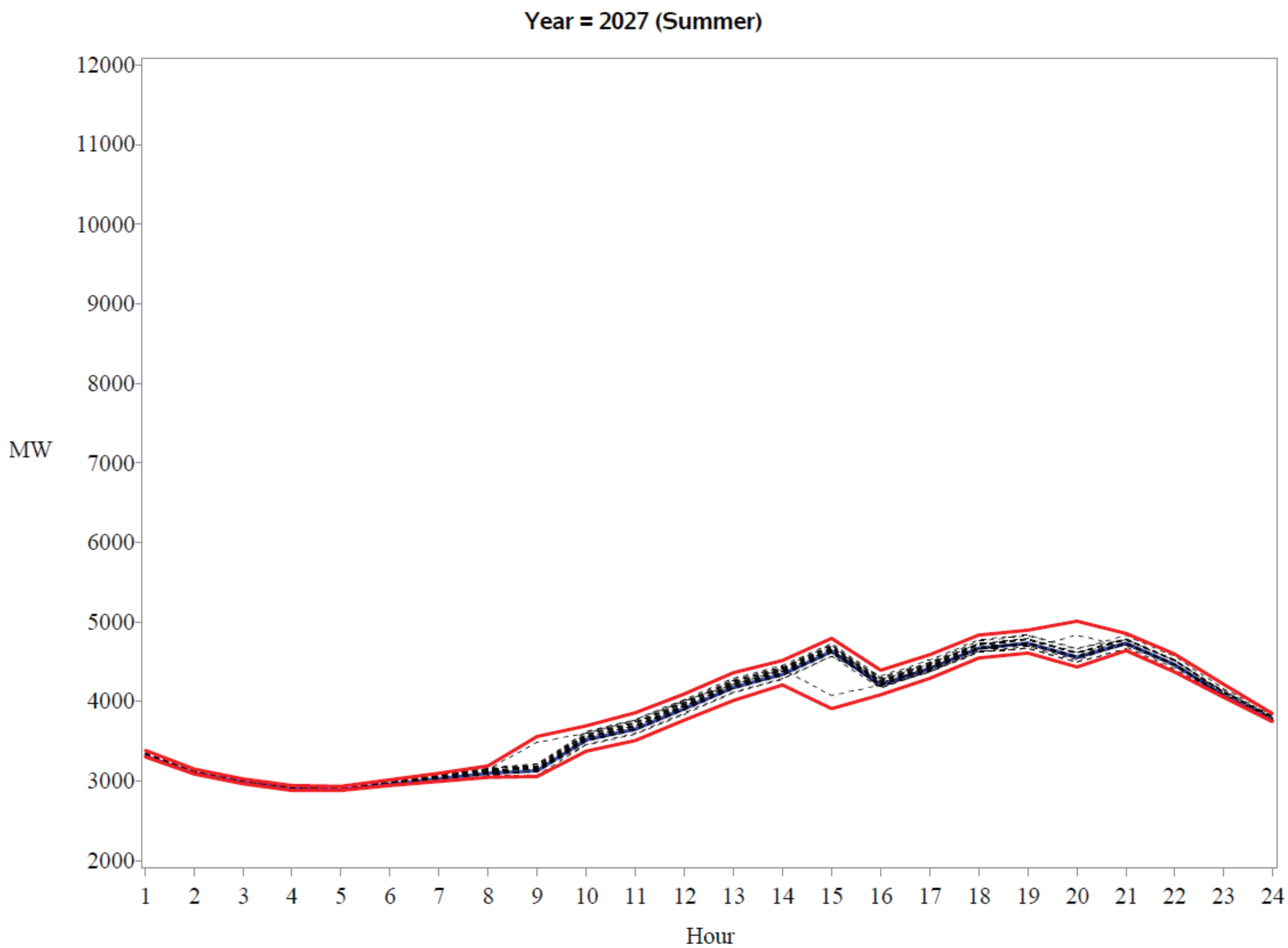

Figure 22: MECO 50/50 case, net summer peak, with range of DER scenarios, year 2027

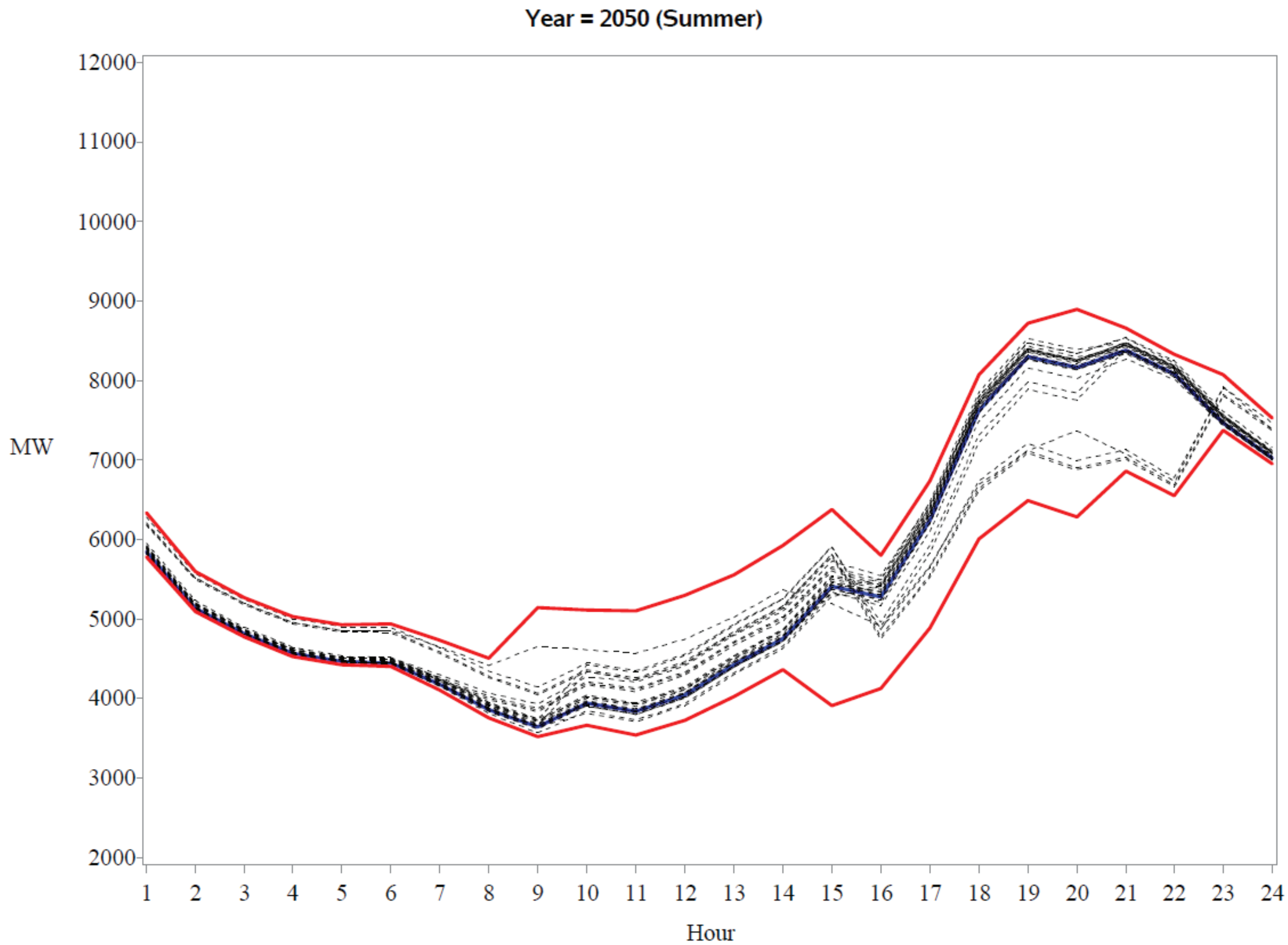

Figure 23: MECO 50/50 case, net summer peak, w/range of DER scenarios, year 2050

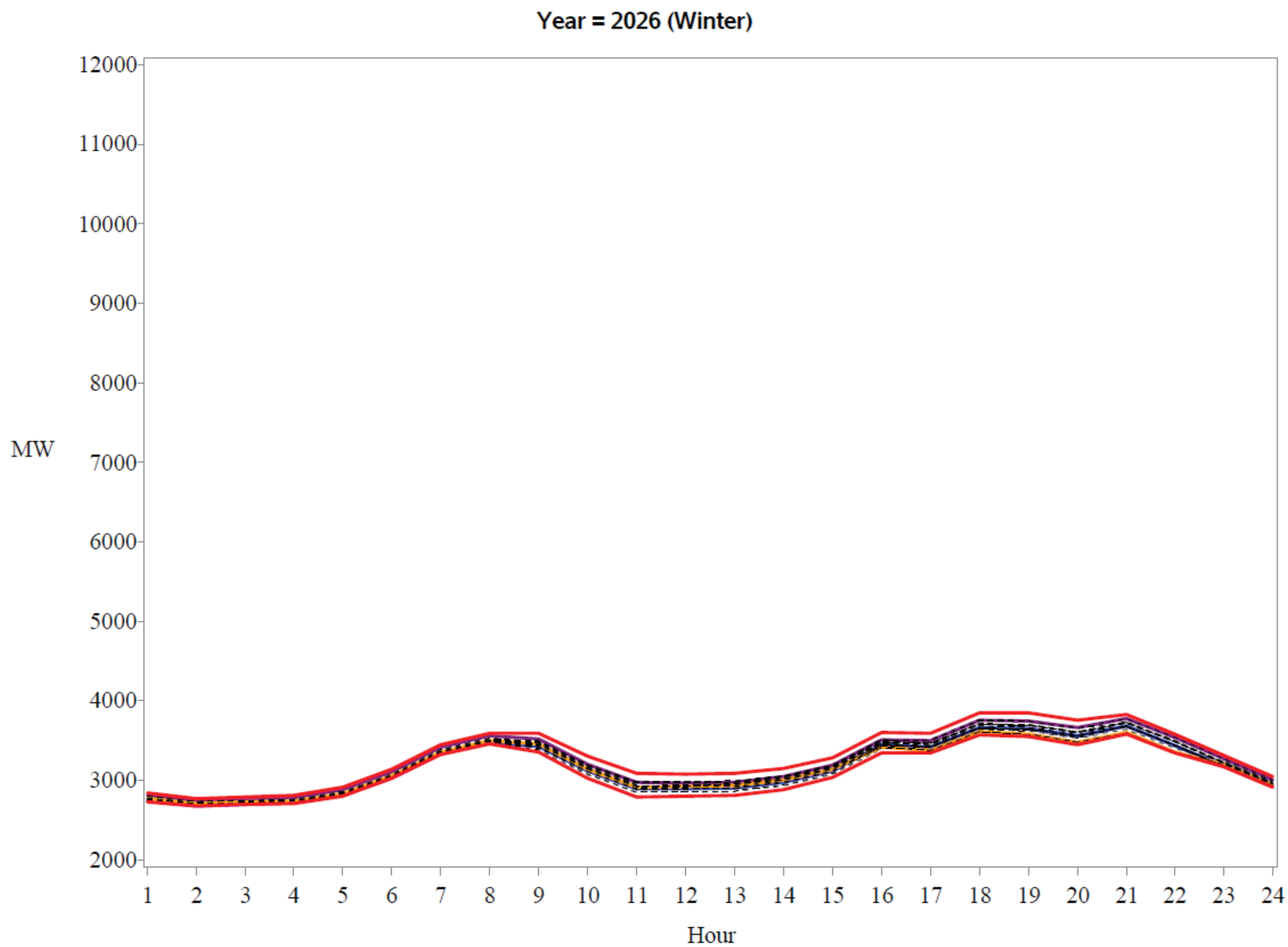

Figure 24: MECO 50/50 case, net winter peak, w/range of DER scenarios, year 2026 (blue = base; red = highest and lowest load scenarios; yellow = managed EV charging; purple = high electrification scenario)

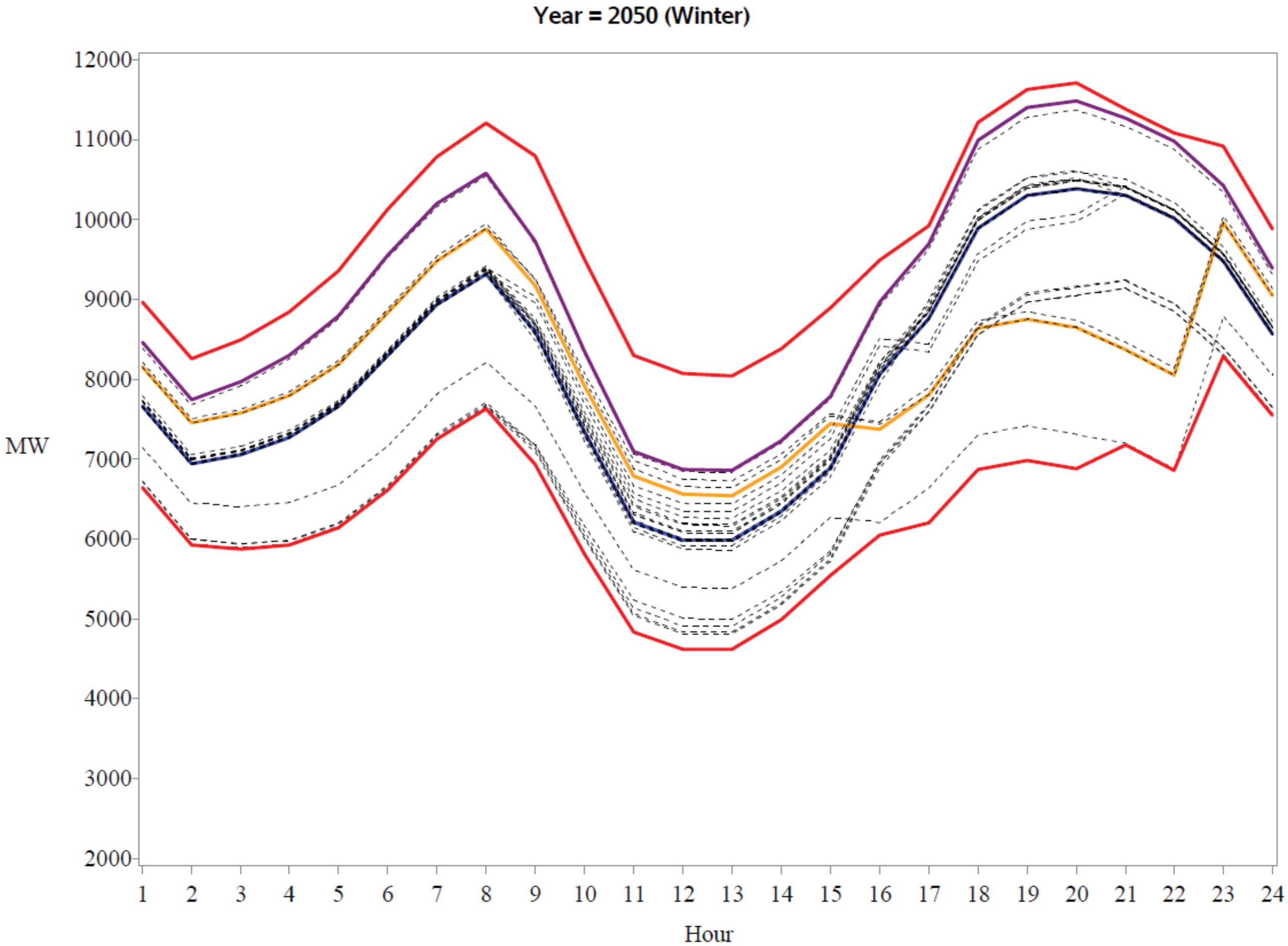

Figure 25: MECO 50/50 case, net winter peak, w/range of DER scenarios, year 2050 (blue = base; red = highest and lowest load scenarios; yellow = managed EV charging; purple = high electrification scenario)

Appendix F and G discuss the DER cases in more detail.

The base case DER projections included in this forecast are based on current trends, approved programs, existing state policy targets, and industrial studies, as appropriate. They are considered the most probable scenario at this time. The higher and lower cases are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive and may or may not capture some of the more ambitious and aspirational type DER scenarios associated with more renewables due to climate and other regional discussions. These can include, among other things, additional electrification of the transportation and heating sectors, and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

Climate Scenarios

The Company provides a climate change scenario based on possible changes in weather over time. This scenario shows potential changes to summer peak loads should average temperatures and volatility increase over time. Figure 26 compares the base case, 50/50 summer peak forecast vs. alternative loads with higher average weather values.

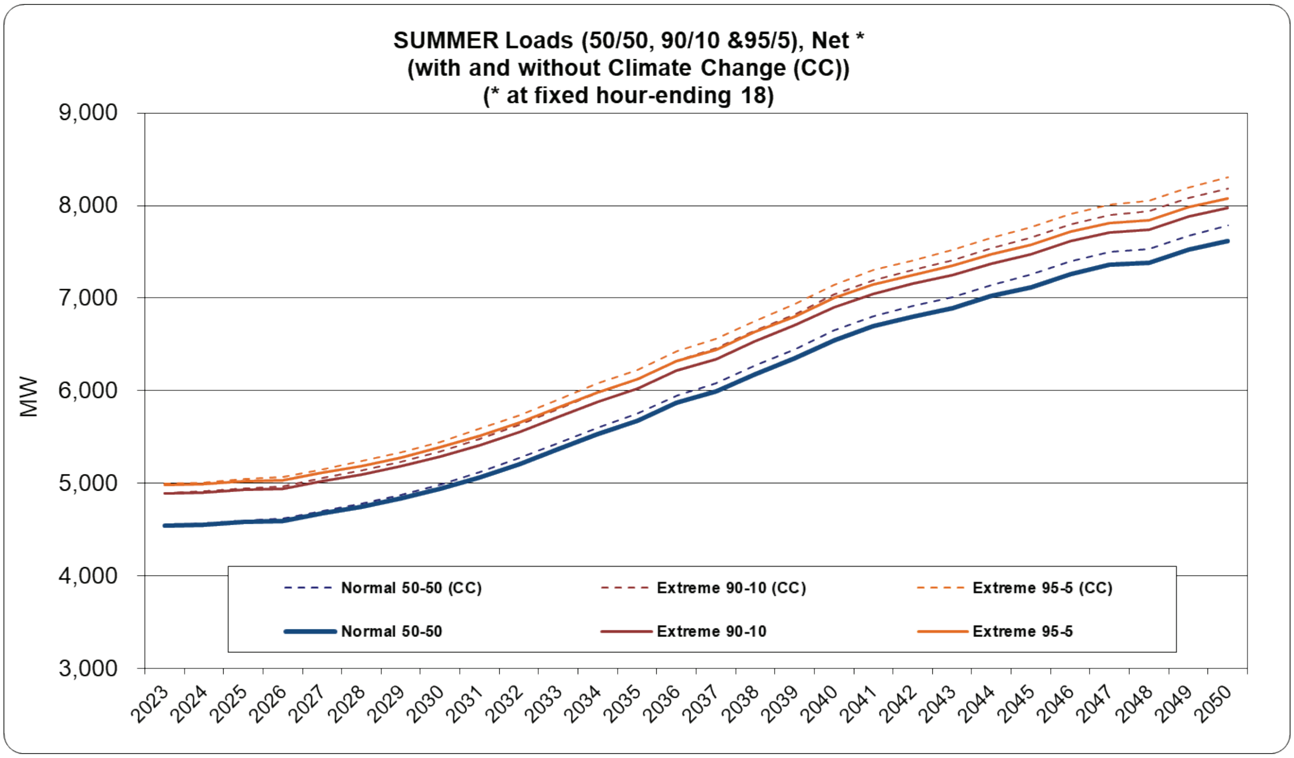

Figure 26 Summer Loads Base case and with Climate Change

The input assumption is a 0.7 degree rise in average temperatures per each ten years and a five percent increase in volatility over that same period. These increases are evenly divided across each year. The temperature increase is selected based on work that the NYISO performed relative to climate change.[22] This is assumed as a proxy for New England. Average temperature is a factor in each of the three weather scenarios. The volatility value of 5% is currently a placeholder. The NYISO report did not assume a value for this, however, since the 90/10 and 95/5 scenarios in this report do include variance in the modeling, a placeholder value was assumed for this exercise.

Table 3 shows the differences between the loads in the base case and the potential higher loads with the climate change assumptions for the three weather scenarios.

[22] *NYISO Climate Change Phase II Study*, page 4, April 2020.

Table 3 Comparison of Summer Loads between Base case and Climate Change Scenario for Year 2050

	50-50		90-10		95-5	
	Base	w/CC	Base	w/CC	Base	w/CC
Year 2050 (MWs)	7,620	7,781	7,978	8,187	8,080	8,302
Delta (MWs)		161		209		223
Delta (%)		2.1%		2.6%		2.8%

Comparison of 2022 Forecast to 2021 Forecast

This year is the first year that the peak forecast is provided for more than 15 years. The comparison to prior year's release can only be done for the next 14 years where the forecast horizon ends in last year's release.

Figure 27 provides a comparison of this year's summer peak forecast to last years and Figure 28 provides a comparison of this year's winter peak forecast to last years

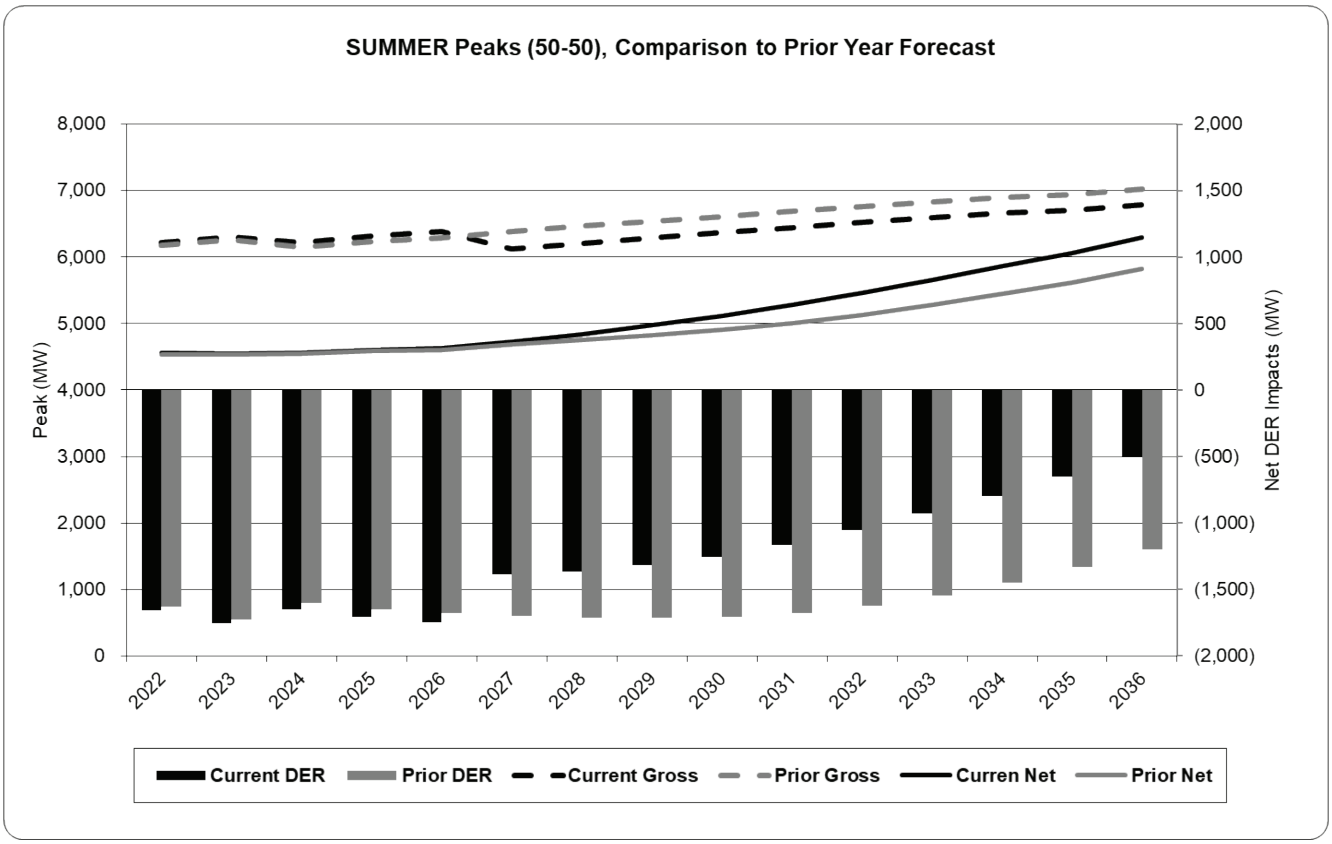

Figure 27 Comparison of current forecast to prior forecast, Gross and Net, Summer 50-50

The "Gross" summer peak load forecast is expected to be similar to the 2021 release for the next four years, and then step down due to the peak hour is expected to shift to later in the evening. The "Net" forecasts are similar in the next five years but becomes higher in later years driven by the lower net DER impacts.

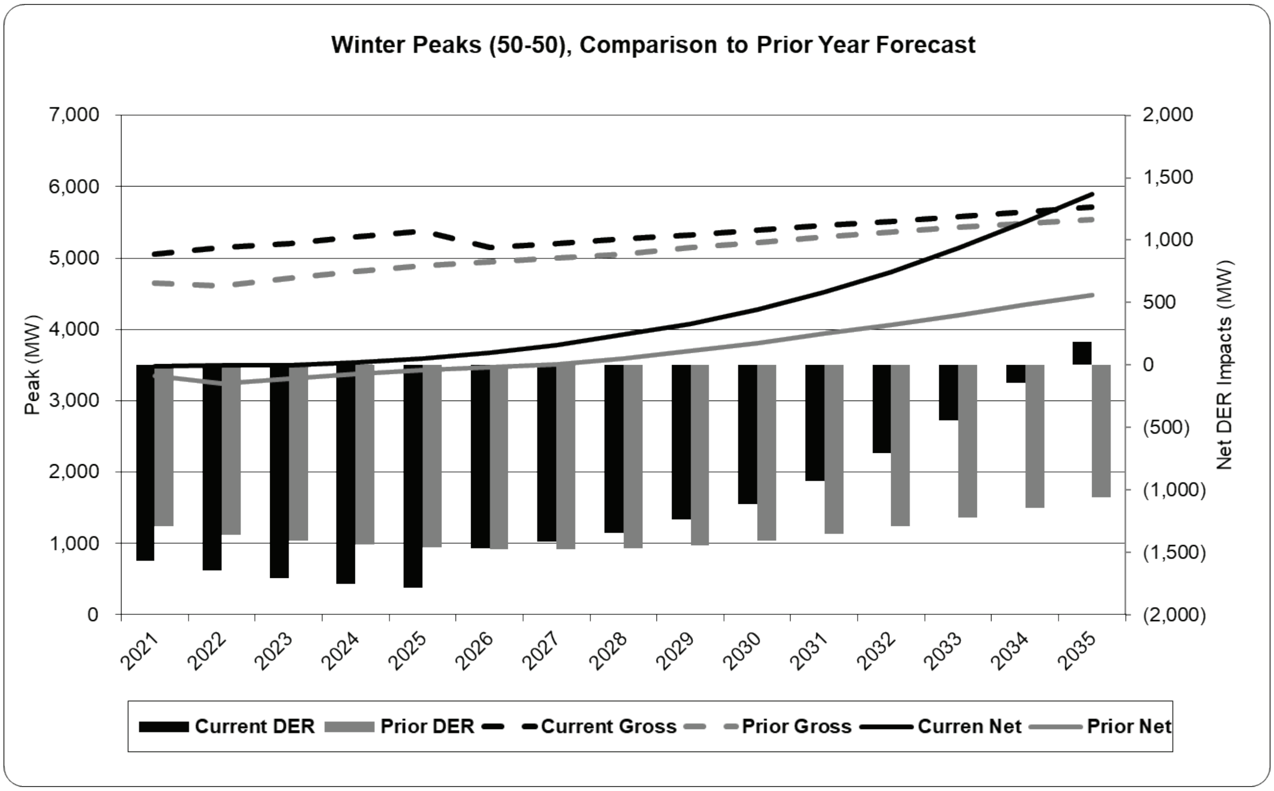

Figure 28 Comparison of current forecast to prior forecast, Gross and Net, Winter 50-50

The “Net” winter peak forecasts are expected to be higher than the 2021 release for the next 14 years. This is because of the joint effect from the higher projected “Gross” load now and lower net DER savings driven by electrifications in the transportation and heating sections.

Appendix A: Forecast Details

MECO (COMPANY)

MECO
Annual Peaks — **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	5,153		4,824		5,118		5,201		S
2007	4,733	-8.1%	4,791	-0.7%	5,075	-0.9%	5,155	-0.9%	S
2008	4,808	1.6%	4,844	1.1%	5,126	1.0%	5,206	1.0%	S
2009	4,518	-6.0%	4,760	-1.7%	5,040	-1.7%	5,119	-1.7%	S
2010	4,874	7.9%	4,739	-0.4%	5,029	-0.2%	5,111	-0.2%	S
2011	5,042	3.4%	4,694	-1.0%	4,974	-1.1%	5,053	-1.1%	S
2012	4,749	-5.8%	4,818	2.6%	5,089	2.3%	5,166	2.2%	S
2013	5,003	5.4%	4,764	-1.1%	5,043	-0.9%	5,123	-0.8%	S
2014	4,379	-12.5%	4,726	-0.8%	5,013	-0.6%	5,095	-0.5%	S
2015	4,384	0.1%	4,647	-1.7%	4,933	-1.6%	5,014	-1.6%	S
2016	4,556	3.9%	4,580	-1.4%	4,857	-1.5%	4,935	-1.6%	S
2017	4,314	-5.3%	4,518	-1.3%	4,800	-1.2%	4,880	-1.1%	S
2018	4,680	8.5%	4,535	0.4%	4,815	0.3%	4,894	0.3%	S
2019	4,339	-7.3%	4,404	-2.9%	4,671	-3.0%	4,746	-3.0%	S
2020	4,497	3.6%	4,610	4.7%	4,894	4.8%	4,974	4.8%	S
2021	4,643	3.2%	4,508	-2.2%	4,769	-2.5%	4,843	-2.6%	S
2022	4,657	0.3%	4,562	1.2%	4,904	2.8%	5,001	3.3%	S
2023	-	-	4,543	-0.4%	4,885	-0.4%	4,989	-0.2%	S
2024	-	-	4,562	0.4%	4,909	0.5%	5,014	0.5%	S
2025	-	-	4,607	1.0%	4,945	0.7%	5,049	0.7%	S
2026	-	-	4,636	0.6%	4,970	0.5%	5,064	0.3%	S
2027	-	-	4,732	2.1%	5,065	1.9%	5,160	1.9%	S
2028	-	-	4,845	2.4%	5,161	1.9%	5,255	1.8%	S
2029	-	-	4,973	2.6%	5,290	2.5%	5,380	2.4%	S
2030	-	-	5,116	2.9%	5,433	2.7%	5,523	2.7%	S
2031	-	-	5,281	3.2%	5,599	3.1%	5,689	3.0%	S
2032	-	-	5,465	3.5%	5,784	3.3%	5,874	3.2%	S
2033	-	-	5,663	3.6%	5,983	3.4%	6,073	3.4%	S
2034	-	-	5,870	3.6%	6,190	3.5%	6,280	3.4%	S
2035	-	-	6,056	3.2%	6,376	3.0%	6,467	3.0%	S
2036	-	-	6,315	4.3%	6,611	3.7%	6,702	3.6%	W
2037	-	-	6,754	7.0%	6,929	4.8%	6,978	4.1%	W
2038	-		7,150	5.9%	7,325	5.7%	7,375	5.7%	W
2039	-		7,563	5.8%	7,740	5.7%	7,790	5.6%	W
2040	-		8,009	5.9%	8,188	5.8%	8,239	5.8%	W
2041	-		8,357	4.3%	8,537	4.3%	8,588	4.2%	W
2042	-		8,698	4.1%	8,880	4.0%	8,932	4.0%	W
2043	-		9,011	3.6%	9,198	3.6%	9,252	3.6%	W
2044	-		9,314	3.4%	9,506	3.3%	9,560	3.3%	W
2045	-		9,572	2.8%	9,765	2.7%	9,820	2.7%	W
2046	-		9,799	2.4%	9,994	2.3%	10,049	2.3%	W
2047	-		10,014	2.2%	10,211	2.2%	10,266	2.2%	W
2048	-		10,218	2.0%	10,417	2.0%	10,473	2.0%	W
2049	-		10,326	1.1%	10,526	1.0%	10,582	1.0%	W
2050	-		10,389	0.6%	10,589	0.6%	10,646	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.2%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	0.2%	0.4%	0.5%
Base 2022			
Avg. next 5 yrs	0.7%	0.6%	0.6%
Avg. next 10 yrs	1.8%	1.7%	1.6%
Avg. next 15 yrs	2.6%	2.3%	2.2%
Avg. next 20 yrs	3.3%	3.0%	2.9%
Avg. next 25 yrs	3.2%	3.0%	2.9%

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response*

MECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	5,153		4,824		5,118		5,201		83.9
2007	4,733	-8.1%	4,791	-0.7%	5,075	-0.9%	5,155	-0.9%	81.8
2008	4,808	1.6%	4,844	1.1%	5,126	1.0%	5,206	1.0%	82.0
2009	4,518	-6.0%	4,760	-1.7%	5,040	-1.7%	5,119	-1.7%	80.1
2010	4,874	7.9%	4,739	-0.4%	5,029	-0.2%	5,111	-0.2%	82.6
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2014	4,379	-12.5%	4,726	-0.8%	5,013	-0.6%	5,095	-0.5%	80.3
2015	4,384	0.1%	4,647	-1.7%	4,933	-1.6%	5,014	-1.6%	79.5
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2017	4,314	-5.3%	4,518	-1.3%	4,800	-1.2%	4,880	-1.1%	80.9
2018	4,680	8.5%	4,535	0.4%	4,815	0.3%	4,894	0.3%	82.7
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2024	-	-	4,562	0.4%	4,909	0.5%	5,014	0.5%	-
2025	-	-	4,607	1.0%	4,945	0.7%	5,049	0.7%	-
2026	-	-	4,636	0.6%	4,970	0.5%	5,064	0.3%	-
2027	-	-	4,732	2.1%	5,065	1.9%	5,160	1.9%	-
2028	-	-	4,845	2.4%	5,161	1.9%	5,255	1.8%	-
2029	-	-	4,973	2.6%	5,290	2.5%	5,380	2.4%	-
2030	-	-	5,116	2.9%	5,433	2.7%	5,523	2.7%	-
2031	-	-	5,281	3.2%	5,599	3.1%	5,689	3.0%	-
2032	-	-	5,465	3.5%	5,784	3.3%	5,874	3.2%	-
2033	-	-	5,663	3.6%	5,983	3.4%	6,073	3.4%	-
2034	-	-	5,870	3.6%	6,190	3.5%	6,280	3.4%	-
2035	-	-	6,056	3.2%	6,376	3.0%	6,467	3.0%	-
2036	-	-	6,290	3.9%	6,611	3.7%	6,702	3.6%	-
2037	-	-	6,459	2.7%	6,780	2.6%	6,871	2.5%	-
2038	-		6,689	3.6%	7,010	3.4%	7,101	3.4%	-
2039	-		6,902	3.2%	7,224	3.1%	7,316	3.0%	-
2040	-		7,143	3.5%	7,466	3.3%	7,557	3.3%	-
2041	-		7,322	2.5%	7,645	2.4%	7,737	2.4%	-
2042	-		7,455	1.8%	7,779	1.7%	7,870	1.7%	-
2043	-		7,576	1.6%	7,900	1.6%	7,991	1.5%	-
2044	-		7,722	1.9%	8,046	1.9%	8,138	1.8%	-
2045	-		7,840	1.5%	8,165	1.5%	8,257	1.5%	-
2046	-		7,990	1.9%	8,316	1.8%	8,408	1.8%	-
2047	-		8,096	1.3%	8,422	1.3%	8,515	1.3%	-
2048	-		8,136	0.5%	8,462	0.5%	8,555	0.5%	-
2049	-		8,276	1.7%	8,603	1.7%	8,696	1.6%	-
2050	-		8,377	1.2%	8,705	1.2%	8,798	1.2%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.2%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	0.2%	0.4%	0.5%
Base 2022			
Avg. next 5 yrs	0.7%	0.6%	0.6%
Avg. next 10 yrs	1.8%	1.7%	1.6%
Avg. next 15 yrs	2.3%	2.2%	2.1%
Avg. next 20 yrs	2.5%	2.3%	2.3%
Avg. next 25 yrs	2.3%	2.2%	2.2%

WTHI

NORMAL	81.7
EXTREME 90/10	83.6
EXTREME 95/5	84.2

*** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

MECO	SUMMER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	4,927	4,825	4,927	4,927	4,927	4,927	4,927	**4,824**	(103)	(0)	0.0	0.0	0.0	0.0	(103)
2007	4,925	4,792	4,924	4,925	4,925	4,925	4,925	**4,791**	(133)	(1)	0.0	0.0	0.0	0.0	(134)
2008	5,010	4,845	5,009	5,010	5,010	5,010	5,010	**4,844**	(164)	(1)	0.0	0.0	0.0	0.0	(165)
2009	4,966	4,763	4,963	4,966	4,966	4,966	4,966	**4,760**	(202)	(3)	0.0	0.0	0.0	0.0	(205)
2010	4,995	4,745	4,989	4,995	4,995	4,995	4,995	**4,739**	(249)	(6)	0.0	0.0	0.0	0.0	(255)
2011	5,007	4,706	4,995	5,007	5,007	5,007	5,007	**4,694**	(301)	(13)	0.0	0.0	0.0	0.0	(314)
2012	5,193	4,835	5,176	5,193	5,193	5,193	5,193	**4,818**	(358)	(17)	0.1	0.0	0.0	0.0	(375)
2013	5,274	4,845	5,192	5,274	5,274	5,274	5,274	**4,764**	(429)	(82)	0.2	0.0	0.0	0.0	(511)
2014	5,355	4,843	5,238	5,356	5,355	5,355	5,355	**4,726**	(512)	(117)	0.4	0.0	0.0	0.0	(629)
2015	5,364	4,759	5,251	5,364	5,364	5,364	5,364	**4,647**	(604)	(113)	0.7	0.0	0.0	0.0	(717)
2016	5,622	4,913	5,288	5,623	5,621	5,622	5,622	**4,580**	(709)	(334)	0.9	(0.3)	0.0	0.0	(1,042)
2017	5,568	4,752	5,340	5,570	5,561	5,568	5,568	**4,518**	(816)	(228)	1.4	(7.3)	(0.2)	0.0	(1,050)
2018	5,601	4,676	5,493	5,604	5,566	5,600	5,601	**4,535**	(925)	(108)	3.0	(34.9)	(1.2)	0.0	(1,066)
2019	5,633	4,596	5,511	5,637	5,569	5,621	5,633	**4,404**	(1,037)	(121)	4.2	(63.3)	(11.4)	0.2	(1,228)
2020	5,982	4,837	5,842	5,988	5,921	5,950	5,983	**4,610**	(1,145)	(140)	5.5	(60.8)	(32.1)	0.6	(1,372)
2021	6,027	4,792	5,863	6,035	5,967	5,958	6,028	**4,508**	(1,235)	(164)	7.6	(59.7)	(68.9)	1.1	(1,519)
2022	6,222	4,930	6,036	6,233	6,141	6,107	6,224	**4,562**	(1,292)	(186)	11.8	(80.7)	(114.9)	2.3	(1,659)
2023	6,300	4,969	6,094	6,320	6,217	6,139	6,305	**4,543**	(1,332)	(206)	19.6	(83.0)	(161.0)	4.4	(1,758)
2024	6,212	4,843	6,183	6,248	6,123	6,005	6,219	**4,562**	(1,368)	(29)	36.6	(88.4)	(207.0)	6.8	(1,649)
2025	6,315	4,915	6,284	6,370	6,222	6,068	6,326	**4,607**	(1,400)	(31)	54.4	(93.9)	(247.5)	10.1	(1,708)
2026	6,382	4,955	6,348	6,461	6,284	6,102	6,396	**4,636**	(1,427)	(34)	78.4	(98.2)	(279.8)	14.1	(1,747)
2027	6,121	4,671	6,121	6,234	6,045	6,129	6,138	**4,732**	(1,450)	0	112.2	(76.6)	8.1	17.0	(1,390)
2028	6,209	4,739	6,209	6,364	6,129	6,218	6,232	**4,845**	(1,470)	0	155.3	(80.3)	8.7	22.3	(1,364)
2029	6,292	4,805	6,292	6,506	6,208	6,301	6,320	**4,973**	(1,487)	0	214.1	(84.2)	9.1	28.3	(1,319)
2030	6,369	4,868	6,369	6,660	6,282	6,379	6,404	**5,116**	(1,501)	0	290.6	(87.4)	9.5	34.7	(1,253)
2031	6,445	4,932	6,445	6,832	6,355	6,454	6,487	**5,281**	(1,513)	0	387.8	(90.0)	9.8	42.0	(1,163)
2032	6,519	4,996	6,519	7,020	6,427	6,529	6,570	**5,465**	(1,523)	0	500.4	(92.4)	10.0	51.0	(1,054)
2033	6,595	5,063	6,595	7,219	6,500	6,605	6,657	**5,663**	(1,532)	0	623.7	(95.2)	10.2	61.7	(931)
2034	6,666	5,127	6,666	7,423	6,568	6,677	6,740	**5,870**	(1,539)	0	756.5	(97.8)	10.3	74.0	(796)
2035	6,708	5,162	6,708	7,604	6,607	6,718	6,795	**6,056**	(1,546)	0	896.7	(100.5)	10.4	87.5	(651)
2036	6,792	5,241	6,792	7,833	6,688	6,802	6,894	**6,290**	(1,551)	0	1,040.9	(103.5)	10.5	101.7	(502)
2037	6,814	5,257	6,814	7,996	6,708	6,825	6,931	**6,459**	(1,557)	0	1,181.8	(106.5)	10.6	116.4	(355)
2038	6,901	5,338	6,901	8,220	6,791	6,912	7,032	**6,689**	(1,563)	0	1,318.6	(109.9)	10.7	131.1	(213)
2039	6,969	5,400	6,969	8,428	6,856	6,980	7,115	**6,902**	(1,569)	0	1,458.9	(113.1)	10.7	145.5	(67)
2040	7,053	5,478	7,053	8,663	6,937	7,063	7,212	**7,143**	(1,575)	0	1,610.4	(115.4)	10.8	159.2	90
2041	7,132	5,552	7,132	8,837	7,015	7,143	7,304	**7,322**	(1,581)	0	1,704.9	(117.2)	10.8	172.0	190
2042	7,176	5,590	7,176	8,966	7,057	7,187	7,360	**7,455**	(1,587)	0	1,789.6	(118.6)	10.8	183.6	279
2043	7,218	5,626	7,218	9,084	7,098	7,229	7,412	**7,576**	(1,592)	0	1,865.5	(120.2)	10.8	193.9	358
2044	7,295	5,697	7,295	9,228	7,174	7,306	7,498	**7,722**	(1,598)	0	1,932.4	(121.6)	10.9	202.7	426
2045	7,356	5,751	7,356	9,346	7,232	7,366	7,566	**7,840**	(1,604)	0	1,990.6	(123.2)	10.9	210.1	484
2046	7,457	5,847	7,457	9,498	7,332	7,468	7,673	**7,990**	(1,610)	0	2,040.7	(125.0)	10.9	216.1	533
2047	7,524	5,908	7,524	9,607	7,397	7,535	7,744	**8,096**	(1,616)	0	2,083.3	(126.8)	10.9	220.7	572
2048	7,532	5,910	7,532	9,651	7,403	7,543	7,756	**8,136**	(1,622)	0	2,119.4	(128.5)	10.9	224.0	604
2049	7,647	6,019	7,647	9,797	7,516	7,658	7,873	**8,276**	(1,628)	0	2,149.9	(130.3)	10.9	226.2	629
2050	7,729	6,095	7,729	9,904	7,597	7,740	7,956	**8,377**	(1,633)	0	2,175.8	(132.1)	10.9	227.1	648

Avg. last 15 yrs	1.6%	0.2%	1.4%	1.6%	1.5%	1.4%	1.6%	-0.3%
Avg. last 10 yrs	1.8%	0.2%	1.5%	1.8%	1.7%	1.6%	1.8%	-0.5%
Avg. last 5 yrs	2.2%	0.7%	2.5%	2.3%	2.0%	1.9%	2.3%	0.2%
Base 2022								
Avg. next 5 yrs	-0.3%	-1.1%	0.3%	0.0%	-0.3%	0.1%	-0.3%	0.7%
Avg. next 10 yrs	0.5%	0.1%	0.8%	1.2%	0.5%	0.7%	0.5%	1.8%
Avg. next 15 yrs	0.6%	0.4%	0.8%	1.7%	0.6%	0.7%	0.7%	2.3%
Avg. next 20 yrs	0.7%	0.6%	0.9%	1.8%	0.7%	0.8%	0.8%	2.5%
Avg. next 25 yrs	0.8%	0.7%	0.9%	1.7%	0.7%	0.8%	0.9%	2.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

MECO
WINTER Peaks after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	3,875		3,860		3,975		4,007		49.1
2007	3,888	0.4%	3,822	-1.0%	3,933	-1.0%	3,965	-1.1%	48.9
2008	3,729	-4.1%	3,796	-0.7%	3,917	-0.4%	3,952	-0.3%	42.3
2009	3,720	-0.3%	3,821	0.6%	3,937	0.5%	3,970	0.5%	38.5
2010	3,807	2.4%	3,679	-3.7%	3,815	-3.1%	3,854	-2.9%	55.1
2011	3,558	-6.5%	3,675	-0.1%	3,804	-0.3%	3,840	-0.3%	46.9
2012	3,760	5.7%	3,723	1.3%	3,853	1.3%	3,889	1.3%	50.0
2013	3,881	3.2%	3,906	4.9%	4,044	5.0%	4,083	5.0%	46.5
2014	3,662	-5.6%	3,611	-7.5%	3,733	-7.7%	3,767	-7.7%	53.1
2015	3,437	-6.2%	3,514	-2.7%	3,628	-2.8%	3,660	-2.8%	43.9
2016	3,499	1.8%	3,471	-1.2%	3,610	-0.5%	3,649	-0.3%	48.0
2017	3,676	5.1%	3,485	0.4%	3,654	1.2%	3,702	1.5%	56.5
2018	3,692	0.4%	3,586	2.9%	3,731	2.1%	3,772	1.9%	53.4
2019	3,291	-10.9%	3,378	-5.8%	3,521	-5.6%	3,561	-5.6%	43.2
2020	3,333	1.3%	3,498	3.6%	3,634	3.2%	3,672	3.1%	41.6
2021	3,529	5.9%	3,486	-0.3%	3,631	-0.1%	3,672	0.0%	47.0
2022	-	-	3,498	0.3%	3,652	0.6%	3,695	0.6%	-
2023		-	3,503	0.1%	3,659	0.2%	3,703	0.2%	
2024		-	3,544	1.2%	3,703	1.2%	3,748	1.2%	
2025	-	-	3,586	1.2%	3,747	1.2%	3,792	1.2%	-
2026	-	-	3,677	2.5%	3,831	2.2%	3,874	2.2%	-
2027	-	-	3,782	2.9%	3,938	2.8%	3,982	2.8%	-
2028	-	-	3,930	3.9%	4,087	3.8%	4,132	3.8%	-
2029	-	-	4,081	3.9%	4,240	3.7%	4,285	3.7%	-
2030	-	-	4,278	4.8%	4,439	4.7%	4,484	4.6%	-
2031	-	-	4,522	5.7%	4,685	5.6%	4,731	5.5%	-
2032	-	-	4,809	6.3%	4,974	6.2%	5,021	6.1%	-
2033	-	-	5,138	6.8%	5,305	6.7%	5,352	6.6%	-
2034	-	-	5,501	7.1%	5,670	6.9%	5,717	6.8%	-
2035	-	-	5,899	7.2%	6,069	7.1%	6,118	7.0%	-
2036	-	-	6,315	7.1%	6,488	6.9%	6,536	6.8%	-
2037	-		6,754	7.0%	6,929	6.8%	6,978	6.8%	-
2038	-		7,150	5.9%	7,325	5.7%	7,375	5.7%	-
2039	-		7,563	5.8%	7,740	5.7%	7,790	5.6%	-
2040	-		8,009	5.9%	8,188	5.8%	8,239	5.8%	-
2041	-		8,357	4.3%	8,537	4.3%	8,588	4.2%	-
2042	-		8,698	4.1%	8,880	4.0%	8,932	4.0%	-
2043	-		9,011	3.6%	9,198	3.6%	9,252	3.6%	-
2044	-		9,314	3.4%	9,506	3.3%	9,560	3.3%	-
2045	-		9,572	2.8%	9,765	2.7%	9,820	2.7%	-
2046	-		9,799	2.4%	9,994	2.3%	10,049	2.3%	-
2047	-		10,014	2.2%	10,211	2.2%	10,266	2.2%	-
2048	-		10,218	2.0%	10,417	2.0%	10,473	2.0%	-
2049	-		10,326	1.1%	10,526	1.0%	10,582	1.0%	-
2050	-		10,389	0.6%	10,589	0.6%	10,646	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.7%	-0.6%	-0.6%
Avg. last 10 yrs	-0.5%	-0.5%	-0.4%
Avg. last 5 yrs	0.1%	0.1%	0.1%
Base 2021			
Avg. next 5 yrs	1.1%	1.1%	1.1%
Avg. next 10 yrs	2.6%	2.6%	2.6%
Avg. next 15 yrs	4.0%	3.9%	3.9%
Avg. next 20 yrs	4.5%	4.4%	4.3%
Avg. next 25 yrs	4.2%	4.1%	4.1%

HDD_wtd

NORMAL	47.9
EXTREME 90/10	55.6
EXTREME 95/5	57.7

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)*

MECO	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	4,042	3,860	4,042	4,042	4,042	4,042	4,042	**3,860**	(181)	0	0.0	0.0	0.0	0.0	(181)
2007	4,060	3,822	4,060	4,060	4,060	4,060	4,060	**3,822**	(238)	0	0.0	0.0	0.0	0.0	(238)
2008	4,068	3,796	4,068	4,068	4,068	4,068	4,068	**3,796**	(272)	0	0.0	0.0	0.0	0.0	(272)
2009	4,156	3,821	4,156	4,156	4,156	4,156	4,156	**3,821**	(336)	0	0.0	0.0	0.0	0.0	(336)
2010	4,071	3,679	4,071	4,071	4,071	4,071	4,071	**3,679**	(392)	0	0.0	0.0	0.0	0.0	(392)
2011	4,127	3,675	4,127	4,127	4,127	4,127	4,127	**3,675**	(452)	0	0.0	0.0	0.0	0.0	(452)
2012	4,242	3,723	4,242	4,243	4,242	4,242	4,242	**3,723**	(519)	0	0.3	0.0	0.0	0.0	(519)
2013	4,515	3,905	4,515	4,515	4,515	4,515	4,515	**3,906**	(609)	0	0.5	0.0	0.0	0.0	(609)
2014	4,317	3,610	4,317	4,318	4,317	4,317	4,317	**3,611**	(707)	0	1.0	0.0	0.0	0.0	(706)
2015	4,328	3,512	4,328	4,330	4,328	4,328	4,328	**3,514**	(816)	0	1.6	0.0	0.0	0.0	(814)
2016	4,397	3,469	4,397	4,399	4,397	4,397	4,397	**3,471**	(928)	0	1.8	0.0	0.0	0.0	(926)
2017	4,526	3,483	4,526	4,528	4,526	4,525	4,526	**3,485**	(1,043)	0	2.8	0.0	(0.4)	0.0	(1,041)
2018	4,753	3,584	4,753	4,757	4,753	4,751	4,753	**3,586**	(1,169)	0	4.4	0.0	(1.8)	0.0	(1,166)
2019	4,683	3,390	4,683	4,689	4,683	4,665	4,684	**3,378**	(1,293)	0	6.1	0.0	(18.4)	0.7	(1,305)
2020	4,947	3,531	4,947	4,955	4,947	4,905	4,949	**3,498**	(1,416)	0	7.7	0.0	(42.4)	2.2	(1,449)
2021	5,055	3,560	5,055	5,066	5,055	4,966	5,059	**3,486**	(1,496)	0	11.1	0.0	(88.7)	4.2	(1,569)
2022	5,143	3,605	5,143	5,161	5,143	5,008	5,153	**3,498**	(1,538)	0	17.8	0.0	(135.1)	9.7	(1,645)
2023	5,208	3,634	5,208	5,238	5,208	5,027	5,229	**3,503**	(1,575)	0	29.9	0.0	(181.4)	20.7	(1,706)
2024	5,300	3,690	5,300	5,346	5,300	5,072	5,335	**3,544**	(1,610)	0	46.6	0.0	(227.8)	35.4	(1,755)
2025	5,371	3,732	5,371	5,440	5,371	5,107	5,421	**3,586**	(1,639)	0	68.5	0.0	(264.5)	50.2	(1,785)
2026	5,143	3,479	5,143	5,274	5,143	5,152	5,203	**3,677**	(1,665)	0	130.4	0.0	8.2	59.7	(1,466)
2027	5,199	3,512	5,199	5,382	5,199	5,207	5,277	**3,782**	(1,686)	0	183.0	0.0	8.8	78.1	(1,416)
2028	5,274	3,570	5,274	5,526	5,274	5,283	5,373	**3,930**	(1,704)	0	251.9	0.0	9.4	98.6	(1,344)
2029	5,323	3,603	5,323	5,670	5,323	5,332	5,443	**4,081**	(1,720)	0	347.7	0.0	9.8	120.8	(1,241)
2030	5,388	3,655	5,388	5,856	5,388	5,399	5,533	**4,278**	(1,733)	0	467.8	0.0	10.1	144.2	(1,111)
2031	5,453	3,708	5,453	6,074	5,453	5,463	5,634	**4,522**	(1,744)	0	621.7	0.0	10.4	181.9	(930)
2032	5,516	3,763	5,516	6,306	5,516	5,527	5,763	**4,809**	(1,754)	0	789.5	0.0	10.6	246.4	(707)
2033	5,580	3,819	5,580	6,553	5,580	5,591	5,916	**5,138**	(1,762)	0	973.1	0.0	10.8	336.0	(442)
2034	5,642	3,873	5,642	6,811	5,642	5,653	6,090	**5,501**	(1,769)	0	1,168.9	0.0	10.9	448.4	(140)
2035	5,709	3,935	5,709	7,082	5,709	5,720	6,290	**5,899**	(1,775)	0	1,372.7	0.0	11.0	580.9	190
2036	5,777	3,996	5,777	7,354	5,777	5,788	6,507	**6,315**	(1,780)	0	1,577.8	0.0	11.1	730.1	539
2037	5,859	4,073	5,859	7,637	5,859	5,870	6,751	**6,754**	(1,786)	0	1,778.0	0.0	11.2	892.2	895
2038	5,896	4,104	5,896	7,867	5,896	5,907	6,959	**7,150**	(1,792)	0	1,971.4	0.0	11.2	1,063.4	1,254
2039	5,940	4,143	5,940	8,110	5,940	5,952	7,180	**7,563**	(1,798)	0	2,169.9	0.0	11.3	1,239.4	1,623
2040	5,999	4,195	5,999	8,386	5,999	6,010	7,415	**8,009**	(1,804)	0	2,386.6	0.0	11.3	1,416.0	2,010
2041	6,049	4,239	6,049	8,566	6,049	6,060	7,638	**8,357**	(1,810)	0	2,516.8	0.0	11.3	1,589.2	2,308
2042	6,112	4,297	6,112	8,747	6,112	6,124	7,867	**8,698**	(1,815)	0	2,634.8	0.0	11.4	1,755.2	2,586
2043	6,171	4,350	6,171	8,911	6,171	6,183	8,082	**9,011**	(1,821)	0	2,739.7	0.0	11.4	1,910.3	2,840
2044	6,440	4,613	6,440	9,209	6,440	6,029	8,785	**9,314**	(1,827)	0	2,768.1	0.0	(411.6)	2,344.3	2,874
2045	6,485	4,652	6,485	9,332	6,485	6,072	8,971	**9,572**	(1,833)	0	2,846.9	0.0	(412.4)	2,485.9	3,087
2046	6,530	4,692	6,530	9,445	6,530	6,118	9,136	**9,799**	(1,839)	0	2,914.7	0.0	(412.4)	2,605.3	3,269
2047	6,598	4,754	6,598	9,571	6,598	6,186	9,299	**10,014**	(1,845)	0	2,972.4	0.0	(412.4)	2,700.4	3,416
2048	6,690	4,839	6,690	9,712	6,690	6,278	9,459	**10,218**	(1,850)	0	3,021.6	0.0	(412.4)	2,769.5	3,528
2049	6,720	4,863	6,720	9,783	6,720	6,307	9,531	**10,326**	(1,856)	0	3,063.5	0.0	(412.4)	2,811.4	3,606
2050	6,738	4,876	6,738	9,838	6,738	6,326	9,564	**10,389**	(1,862)	0	3,099.3	0.0	(412.4)	2,825.4	3,650

	-							
Avg. last 15 yrs	1.5%	-0.5%	1.5%	1.5%	1.5%	1.4%	1.5%	-0.7%
Avg. last 10 yrs	2.0%	-0.3%	2.0%	2.1%	2.0%	1.9%	2.1%	-0.5%
Avg. last 5 yrs	2.8%	0.5%	2.8%	2.9%	2.8%	2.5%	2.8%	0.1%
Base 2021								
Avg. next 5 yrs	0.3%	-0.5%	0.3%	0.8%	0.3%	0.7%	0.6%	1.1%
Avg. next 10 yrs	0.8%	0.4%	0.8%	1.8%	0.8%	1.0%	1.1%	2.6%
Avg. next 15 yrs	0.9%	0.8%	0.9%	2.5%	0.9%	1.0%	1.7%	4.0%
Avg. next 20 yrs	1.0%	0.9%	1.0%	2.8%	1.0%	1.1%	2.2%	4.7%
Avg. next 25 yrs	1.1%	1.2%	1.1%	2.6%	1.1%	0.9%	2.5%	4.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

NEMA Zone (Northeast Massachusetts)

NEMA
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	1,262		1,190		1,282		1,308		S
2007	1,155	-8.5%	1,166	-2.1%	1,252	-2.3%	1,277	-2.4%	S
2008	1,122	-2.8%	1,174	0.7%	1,264	0.9%	1,289	1.0%	S
2009	1,115	-0.6%	1,179	0.4%	1,265	0.1%	1,289	0.0%	S
2010	1,203	7.9%	1,205	2.2%	1,292	2.2%	1,317	2.2%	S
2011	1,259	4.6%	1,172	-2.7%	1,257	-2.7%	1,281	-2.7%	S
2012	1,169	-7.1%	1,195	2.0%	1,281	1.9%	1,305	1.9%	S
2013	1,227	4.9%	1,172	-2.0%	1,257	-1.9%	1,281	-1.8%	S
2014	1,094	-10.9%	1,155	-1.4%	1,242	-1.2%	1,266	-1.1%	S
2015	1,082	-1.0%	1,131	-2.1%	1,218	-1.9%	1,243	-1.8%	S
2016	1,126	4.0%	1,086	-4.0%	1,168	-4.2%	1,191	-4.2%	S
2017	1,044	-7.3%	1,076	-0.9%	1,160	-0.7%	1,183	-0.6%	S
2018	1,150	10.2%	1,094	1.7%	1,181	1.8%	1,206	1.9%	S
2019	1,078	-6.3%	1,076	-1.7%	1,158	-2.0%	1,181	-2.0%	S
2020	1,136	5.4%	1,189	10.5%	1,281	10.6%	1,307	10.7%	S
2021	1,175	3.4%	1,074	-9.7%	1,170	-8.6%	1,198	-8.4%	S
2022	1,176	0.1%	1,114	3.7%	1,204	2.9%	1,230	2.7%	S
2023	-	-	1,120	0.6%	1,207	0.2%	1,232	0.1%	S
2024	-	-	1,135	1.3%	1,222	1.2%	1,247	1.2%	S
2025	-	-	1,154	1.7%	1,241	1.5%	1,265	1.5%	S
2026	-	-	1,168	1.3%	1,256	1.2%	1,280	1.2%	S
2027	-	-	1,196	2.4%	1,284	2.2%	1,308	2.2%	S
2028	-	-	1,225	2.4%	1,312	2.2%	1,337	2.2%	S
2029	-	-	1,258	2.7%	1,345	2.5%	1,370	2.5%	S
2030	-	-	1,296	3.0%	1,383	2.8%	1,408	2.8%	S
2031	-	-	1,341	3.5%	1,429	3.3%	1,454	3.2%	S
2032	-	-	1,392	3.8%	1,480	3.6%	1,505	3.5%	S
2033	-	-	1,447	4.0%	1,535	3.7%	1,560	3.7%	S
2034	-	-	1,517	4.8%	1,593	3.8%	1,618	3.7%	W
2035	-	-	1,632	7.6%	1,690	6.1%	1,706	5.4%	W
2036	-	-	1,752	7.3%	1,810	7.1%	1,827	7.1%	W
2037	-	-	1,878	7.2%	1,937	7.0%	1,954	7.0%	W
2038	-		1,990	6.0%	2,050	5.8%	2,067	5.8%	W
2039	-		2,107	5.9%	2,167	5.7%	2,185	5.7%	W
2040	-		2,235	6.0%	2,295	5.9%	2,313	5.9%	W
2041	-		2,331	4.3%	2,393	4.2%	2,410	4.2%	W
2042	-		2,427	4.1%	2,489	4.0%	2,507	4.0%	W
2043	-		2,514	3.6%	2,578	3.6%	2,597	3.6%	W
2044	-		2,598	3.3%	2,664	3.3%	2,683	3.3%	W
2045	-		2,669	2.7%	2,736	2.7%	2,754	2.7%	W
2046	-		2,732	2.4%	2,799	2.3%	2,818	2.3%	W
2047	-		2,793	2.2%	2,861	2.2%	2,880	2.2%	W
2048	-		2,853	2.1%	2,921	2.1%	2,941	2.1%	W
2049	-		2,884	1.1%	2,953	1.1%	2,972	1.1%	W
2050	-		2,903	0.7%	2,972	0.6%	2,992	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.3%	-0.2%
Avg. last 10 yrs	-0.7%	-0.6%	-0.6%
Avg. last 5 yrs	0.7%	0.8%	0.8%
Base 2022			
Avg. next 5 yrs	1.4%	1.3%	1.2%
Avg. next 10 yrs	2.3%	2.1%	2.0%
Avg. next 15 yrs	3.5%	3.2%	3.1%
Avg. next 20 yrs	4.0%	3.7%	3.6%
Avg. next 25 yrs	3.7%	3.5%	3.5%

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

NEMA

SUMMER Peaks — **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	1,262		1,190		1,282		1,308		84.5
2007	1,155	-8.5%	1,166	-2.1%	1,252	-2.3%	1,277	-2.4%	82.7
2008	1,122	-2.8%	1,174	0.7%	1,264	0.9%	1,289	1.0%	82.3
2009	1,115	-0.6%	1,179	0.4%	1,265	0.1%	1,289	0.0%	81.0
2010	1,203	7.9%	1,205	2.2%	1,292	2.2%	1,317	2.2%	82.6
2011	1,259	4.6%	1,172	-2.7%	1,257	-2.7%	1,281	-2.7%	85.7
2012	1,169	-7.1%	1,195	2.0%	1,281	1.9%	1,305	1.9%	82.0
2013	1,227	4.9%	1,172	-2.0%	1,257	-1.9%	1,281	-1.8%	84.2
2014	1,094	-10.9%	1,155	-1.4%	1,242	-1.2%	1,266	-1.1%	81.1
2015	1,082	-1.0%	1,131	-2.1%	1,218	-1.9%	1,243	-1.8%	81.4
2016	1,126	4.0%	1,086	-4.0%	1,168	-4.2%	1,191	-4.2%	84.1
2017	1,044	-7.3%	1,076	-0.9%	1,160	-0.7%	1,183	-0.6%	82.0
2018	1,150	10.2%	1,094	1.7%	1,181	1.8%	1,206	1.9%	84.2
2019	1,078	-6.3%	1,076	-1.7%	1,158	-2.0%	1,181	-2.0%	82.7
2020	1,136	5.4%	1,189	10.5%	1,281	10.6%	1,307	10.7%	81.4
2021	1,175	3.4%	1,074	-9.7%	1,170	-8.6%	1,198	-8.4%	85.3
2022	1,176	0.1%	1,114	3.7%	1,204	2.9%	1,230	2.7%	84.5
2023	-	-	1,120	0.6%	1,207	0.2%	1,232	0.1%	-
2024	-	-	1,135	1.3%	1,222	1.2%	1,247	1.2%	-
2025	-	-	1,154	1.7%	1,241	1.5%	1,265	1.5%	-
2026	-	-	1,168	1.3%	1,256	1.2%	1,280	1.2%	-
2027	-	-	1,196	2.4%	1,284	2.2%	1,308	2.2%	-
2028	-	-	1,225	2.4%	1,312	2.2%	1,337	2.2%	-
2029	-	-	1,258	2.7%	1,345	2.5%	1,370	2.5%	-
2030	-	-	1,296	3.0%	1,383	2.8%	1,408	2.8%	-
2031	-	-	1,341	3.5%	1,429	3.3%	1,454	3.2%	-
2032	-	-	1,392	3.8%	1,480	3.6%	1,505	3.5%	-
2033	-	-	1,447	4.0%	1,535	3.7%	1,560	3.7%	-
2034	-	-	1,505	4.0%	1,593	3.8%	1,618	3.7%	-
2035	-	-	1,560	3.6%	1,648	3.4%	1,673	3.4%	-
2036	-	-	1,625	4.2%	1,713	4.0%	1,738	3.9%	-
2037	-	-	1,676	3.1%	1,764	3.0%	1,789	2.9%	-
2038	-		1,739	3.8%	1,827	3.6%	1,852	3.6%	-
2039	-		1,800	3.5%	1,888	3.3%	1,913	3.3%	-
2040	-		1,867	3.7%	1,955	3.6%	1,980	3.5%	-
2041	-		1,915	2.6%	2,004	2.5%	2,029	2.4%	-
2042	-		1,953	1.9%	2,041	1.9%	2,066	1.8%	-
2043	-		1,986	1.7%	2,075	1.7%	2,100	1.6%	-
2044	-		2,025	1.9%	2,113	1.8%	2,138	1.8%	-
2045	-		2,056	1.6%	2,145	1.5%	2,170	1.5%	-
2046	-		2,093	1.8%	2,182	1.7%	2,207	1.7%	-
2047	-		2,121	1.3%	2,209	1.2%	2,234	1.2%	-
2048	-		2,133	0.6%	2,221	0.6%	2,247	0.5%	-
2049	-		2,166	1.6%	2,255	1.5%	2,280	1.5%	-
2050	-		2,190	1.1%	2,279	1.1%	2,304	1.1%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.3%	-0.3%	-0.2%
Avg. last 10 yrs	-0.7%	-0.6%	-0.6%
Avg. last 5 yrs	0.7%	0.8%	0.8%
Base 2022			
Avg. next 5 yrs	1.4%	1.3%	1.2%
Avg. next 10 yrs	2.3%	2.1%	2.0%
Avg. next 15 yrs	2.8%	2.6%	2.5%
Avg. next 20 yrs	2.8%	2.7%	2.6%
Avg. next 25 yrs	2.6%	2.5%	2.4%

WTHI

NORMAL	82.7
EXTREME 90/10	85.0
EXTREME 95/5	85.6

***** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

NEMA	SUMMER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,215	1,190	1,215	1,215	1,215	1,215	1,215	**1,190**	(24)	(0)	0.0	0.0	0.0	0.0	(25)
2007	1,198	1,166	1,197	1,198	1,198	1,198	1,198	**1,166**	(32)	(0)	0.0	0.0	0.0	0.0	(32)
2008	1,213	1,174	1,213	1,213	1,213	1,213	1,213	**1,174**	(39)	(0)	0.0	0.0	0.0	0.0	(39)
2009	1,228	1,180	1,227	1,228	1,228	1,228	1,228	**1,179**	(48)	(1)	0.0	0.0	0.0	0.0	(49)
2010	1,266	1,206	1,265	1,266	1,266	1,266	1,266	**1,205**	(60)	(2)	0.0	0.0	0.0	0.0	(62)
2011	1,247	1,175	1,245	1,247	1,247	1,247	1,247	**1,172**	(73)	(3)	0.0	0.0	0.0	0.0	(76)
2012	1,284	1,197	1,282	1,284	1,284	1,284	1,284	**1,195**	(87)	(1)	0.0	0.0	0.0	0.0	(88)
2013	1,283	1,178	1,276	1,283	1,283	1,283	1,283	**1,172**	(104)	(7)	0.1	0.0	0.0	0.0	(111)
2014	1,297	1,173	1,280	1,298	1,297	1,297	1,297	**1,155**	(125)	(18)	0.1	0.0	0.0	0.0	(142)
2015	1,295	1,147	1,278	1,295	1,295	1,295	1,295	**1,131**	(147)	(16)	0.2	0.0	0.0	0.0	(164)
2016	1,296	1,123	1,258	1,297	1,296	1,296	1,296	**1,086**	(173)	(38)	0.3	(0.1)	0.0	0.0	(211)
2017	1,309	1,110	1,276	1,309	1,307	1,309	1,309	**1,076**	(199)	(33)	0.4	(1.8)	(0.1)	0.0	(233)
2018	1,343	1,118	1,328	1,344	1,335	1,343	1,343	**1,094**	(226)	(15)	0.9	(8.4)	(0.3)	0.0	(249)
2019	1,363	1,110	1,345	1,364	1,348	1,360	1,363	**1,076**	(253)	(18)	1.3	(15.3)	(2.8)	0.0	(287)
2020	1,509	1,229	1,489	1,511	1,495	1,502	1,510	**1,189**	(280)	(20)	1.7	(14.7)	(7.8)	0.1	(321)
2021	1,427	1,125	1,405	1,430	1,413	1,411	1,428	**1,074**	(303)	(23)	2.3	(14.5)	(16.7)	0.3	(354)
2022	1,500	1,183	1,474	1,503	1,480	1,472	1,500	**1,114**	(317)	(26)	3.6	(19.6)	(27.8)	0.6	(386)
2023	1,453	1,126	1,453	1,460	1,438	1,454	1,454	**1,120**	(327)	0	7.4	(15.1)	1.0	0.9	(333)
2024	1,473	1,136	1,473	1,484	1,456	1,474	1,474	**1,135**	(336)	0	11.8	(16.1)	1.3	1.5	(338)
2025	1,494	1,150	1,494	1,511	1,477	1,495	1,496	**1,154**	(344)	0	17.5	(17.1)	1.6	2.2	(340)
2026	1,507	1,156	1,507	1,532	1,489	1,509	1,510	**1,168**	(351)	0	25.2	(17.9)	1.8	3.0	(339)
2027	1,530	1,173	1,530	1,566	1,512	1,532	1,534	**1,196**	(357)	0	35.6	(18.6)	2.0	4.1	(334)
2028	1,549	1,187	1,549	1,598	1,530	1,551	1,555	**1,225**	(362)	0	49.2	(19.5)	2.1	5.4	(324)
2029	1,567	1,201	1,567	1,635	1,547	1,569	1,574	**1,258**	(366)	0	67.9	(20.4)	2.2	6.9	(309)
2030	1,584	1,214	1,584	1,676	1,562	1,586	1,592	**1,296**	(369)	0	92.2	(21.2)	2.3	8.4	(288)
2031	1,600	1,227	1,600	1,723	1,578	1,602	1,610	**1,341**	(373)	0	123.0	(21.8)	2.4	10.2	(259)
2032	1,616	1,241	1,616	1,775	1,594	1,618	1,628	**1,392**	(375)	0	158.7	(22.4)	2.4	12.4	(224)
2033	1,632	1,255	1,632	1,830	1,609	1,635	1,647	**1,447**	(377)	0	197.8	(23.1)	2.5	15.0	(185)
2034	1,648	1,269	1,648	1,888	1,624	1,650	1,666	**1,505**	(379)	0	239.9	(23.7)	2.5	18.0	(142)
2035	1,657	1,276	1,657	1,941	1,632	1,659	1,678	**1,560**	(381)	0	284.4	(24.4)	2.5	21.3	(97)
2036	1,675	1,293	1,675	2,005	1,650	1,677	1,700	**1,625**	(382)	0	330.1	(25.1)	2.6	24.8	(50)
2037	1,680	1,296	1,680	2,054	1,654	1,682	1,708	**1,676**	(384)	0	374.8	(25.9)	2.6	28.3	(4)
2038	1,699	1,313	1,699	2,117	1,672	1,701	1,730	**1,739**	(385)	0	418.1	(26.7)	2.6	31.9	41
2039	1,713	1,327	1,713	2,176	1,686	1,716	1,749	**1,800**	(387)	0	462.5	(27.5)	2.6	35.4	86
2040	1,731	1,343	1,731	2,242	1,703	1,734	1,770	**1,867**	(388)	0	510.6	(28.0)	2.6	38.8	136
2041	1,748	1,359	1,748	2,289	1,720	1,751	1,790	**1,915**	(390)	0	540.5	(28.4)	2.6	41.9	167
2042	1,758	1,367	1,758	2,325	1,729	1,760	1,802	**1,953**	(391)	0	567.4	(28.8)	2.6	44.7	195
2043	1,767	1,374	1,767	2,358	1,738	1,769	1,814	**1,986**	(393)	0	591.5	(29.2)	2.6	47.2	220
2044	1,784	1,390	1,784	2,396	1,754	1,786	1,833	**2,025**	(394)	0	612.7	(29.5)	2.6	49.4	241
2045	1,797	1,401	1,797	2,428	1,767	1,799	1,848	**2,056**	(395)	0	631.2	(29.9)	2.6	51.2	260
2046	1,818	1,421	1,818	2,466	1,788	1,821	1,871	**2,093**	(397)	0	647.1	(30.3)	2.6	52.6	275
2047	1,833	1,434	1,833	2,494	1,802	1,835	1,887	**2,121**	(398)	0	660.7	(30.8)	2.6	53.7	288
2048	1,835	1,435	1,835	2,507	1,803	1,837	1,889	**2,133**	(400)	0	672.2	(31.2)	2.6	54.5	298
2049	1,859	1,458	1,859	2,541	1,828	1,862	1,914	**2,166**	(401)	0	682.0	(31.6)	2.6	55.1	307
2050	1,877	1,474	1,877	2,567	1,845	1,880	1,932	**2,190**	(403)	0	690.2	(32.1)	2.6	55.3	313

Avg. last 15 yrs	1.5%	0.1%	1.4%	1.5%	1.4%	1.4%	1.5%	-0.3%
Avg. last 10 yrs	1.6%	-0.1%	1.4%	1.6%	1.4%	1.4%	1.6%	-0.7%
Avg. last 5 yrs	2.8%	1.3%	2.9%	2.8%	2.5%	2.4%	2.8%	0.7%
Base 2022								
Avg. next 5 yrs	0.4%	-0.2%	0.8%	0.8%	0.4%	0.8%	0.5%	1.4%
Avg. next 10 yrs	0.8%	0.5%	0.9%	1.7%	0.7%	1.0%	0.8%	2.3%
Avg. next 15 yrs	0.8%	0.6%	0.9%	2.1%	0.7%	0.9%	0.9%	2.8%
Avg. next 20 yrs	0.8%	0.7%	0.9%	2.2%	0.8%	0.9%	0.9%	2.8%
Avg. next 25 yrs	1.7%	1.6%	1.8%	3.8%	1.6%	1.8%	1.9%	4.6%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

NEMA
WINTER Peaks — **after DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	946		991		1,033		1,045		45.2
2007	956	1.0%	945	-4.7%	980	-5.1%	990	-5.3%	47.6
2008	908	-5.0%	937	-0.9%	976	-0.5%	987	-0.4%	40.4
2009	918	1.1%	955	2.0%	997	2.2%	1,009	2.3%	37.6
2010	940	2.4%	911	-4.7%	954	-4.4%	966	-4.3%	54.0
2011	865	-8.0%	908	-0.3%	949	-0.5%	961	-0.5%	45.3
2012	906	4.8%	895	-1.4%	931	-1.9%	942	-2.0%	53.6
2013	926	2.2%	898	0.3%	937	0.6%	948	0.7%	54.0
2014	886	-4.4%	874	-2.6%	911	-2.8%	922	-2.8%	52.3
2015	840	-5.2%	833	-4.7%	869	-4.7%	879	-4.6%	57.7
2016	836	-0.5%	835	0.2%	877	0.9%	888	1.1%	46.5
2017	887	6.2%	828	-0.8%	882	0.6%	897	1.0%	57.4
2018	897	1.0%	887	7.1%	936	6.2%	950	5.9%	50.0
2019	791	-11.8%	832	-6.2%	876	-6.4%	889	-6.5%	39.7
2020	818	3.5%	882	6.0%	929	6.0%	942	6.0%	40.1
2021	846	3.4%	844	-4.3%	889	-4.3%	902	-4.2%	45.4
2022	-	-	885	4.9%	935	5.2%	949	5.2%	-
2023		-	903	2.0%	954	2.0%	968	2.0%	
2024		-	921	2.0%	973	2.0%	987	2.0%	
2025	-	-	937	1.8%	990	1.8%	1,005	1.8%	-
2026	-	-	968	3.2%	1,019	2.9%	1,033	2.8%	-
2027	-	-	1,001	3.4%	1,052	3.3%	1,067	3.3%	-
2028	-	-	1,047	4.6%	1,099	4.4%	1,114	4.4%	-
2029	-	-	1,093	4.5%	1,146	4.3%	1,161	4.3%	-
2030	-	-	1,154	5.5%	1,208	5.4%	1,223	5.3%	-
2031	-	-	1,228	6.5%	1,283	6.2%	1,298	6.2%	-
2032	-	-	1,314	7.0%	1,369	6.7%	1,385	6.7%	-
2033	-	-	1,411	7.4%	1,467	7.1%	1,483	7.1%	-
2034	-	-	1,517	7.5%	1,574	7.3%	1,590	7.2%	-
2035	-	-	1,632	7.6%	1,690	7.4%	1,706	7.3%	-
2036	-	-	1,752	7.3%	1,810	7.1%	1,827	7.1%	-
2037	-		1,878	7.2%	1,937	7.0%	1,954	7.0%	-
2038	-		1,990	6.0%	2,050	5.8%	2,067	5.8%	-
2039	-		2,107	5.9%	2,167	5.7%	2,185	5.7%	-
2040	-		2,235	6.0%	2,295	5.9%	2,313	5.9%	-
2041	-		2,331	4.3%	2,393	4.2%	2,410	4.2%	-
2042	-		2,427	4.1%	2,489	4.0%	2,507	4.0%	-
2043	-		2,514	3.6%	2,578	3.6%	2,597	3.6%	-
2044	-		2,598	3.3%	2,664	3.3%	2,683	3.3%	-
2045	-		2,669	2.7%	2,736	2.7%	2,754	2.7%	-
2046	-		2,732	2.4%	2,799	2.3%	2,818	2.3%	-
2047	-		2,793	2.2%	2,861	2.2%	2,880	2.2%	-
2048	-		2,853	2.1%	2,921	2.1%	2,941	2.1%	-
2049	-		2,884	1.1%	2,953	1.1%	2,972	1.1%	-
2050	-		2,903	0.7%	2,972	0.6%	2,992	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-1.1%	-1.0%	-1.0%
Avg. last 10 yrs	-0.7%	-0.7%	-0.6%
Avg. last 5 yrs	0.2%	0.3%	0.3%
Base 2021			
Avg. next 5 yrs	2.8%	2.8%	2.8%
Avg. next 10 yrs	3.8%	3.7%	3.7%
Avg. next 15 yrs	5.0%	4.9%	4.8%
Avg. next 20 yrs	5.2%	5.1%	5.0%
Avg. next 25 yrs	4.8%	4.7%	4.7%

HDD_wtd

NORMAL	47.7
EXTREME 90/10	56.5
EXTREME 95/5	59.0

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)***

NEMA	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,035	991	1,035	1,035	1,035	1,035	1,035	**991**	(44)	0	0.0	0.0	0.0	0.0	(44)
2007	1,003	945	1,003	1,003	1,003	1,003	1,003	**945**	(58)	0	0.0	0.0	0.0	0.0	(58)
2008	1,003	937	1,003	1,003	1,003	1,003	1,003	**937**	(66)	0	0.0	0.0	0.0	0.0	(66)
2009	1,037	955	1,037	1,037	1,037	1,037	1,037	**955**	(82)	0	0.0	0.0	0.0	0.0	(82)
2010	1,007	911	1,007	1,007	1,007	1,007	1,007	**911**	(96)	0	0.0	0.0	0.0	0.0	(96)
2011	1,018	908	1,018	1,018	1,018	1,018	1,018	**908**	(110)	0	0.0	0.0	0.0	0.0	(110)
2012	1,021	895	1,021	1,021	1,021	1,021	1,021	**895**	(126)	0	0.1	0.0	0.0	0.0	(126)
2013	1,045	898	1,045	1,045	1,045	1,045	1,045	**898**	(148)	0	0.1	0.0	0.0	0.0	(147)
2014	1,045	874	1,045	1,045	1,045	1,045	1,045	**874**	(171)	0	0.3	0.0	0.0	0.0	(171)
2015	1,030	833	1,030	1,030	1,030	1,030	1,030	**833**	(197)	0	0.5	0.0	0.0	0.0	(197)
2016	1,058	835	1,058	1,059	1,058	1,058	1,058	**835**	(224)	0	0.5	0.0	0.0	0.0	(223)
2017	1,079	827	1,079	1,080	1,079	1,079	1,079	**828**	(251)	0	0.8	0.0	(0.1)	0.0	(251)
2018	1,168	886	1,168	1,169	1,168	1,167	1,168	**887**	(282)	0	1.3	0.0	(0.4)	0.0	(281)
2019	1,146	834	1,146	1,148	1,146	1,141	1,146	**832**	(312)	0	1.8	0.0	(4.5)	0.2	(314)
2020	1,231	889	1,231	1,233	1,231	1,221	1,231	**882**	(342)	0	2.3	0.0	(10.3)	0.5	(349)
2021	1,221	861	1,221	1,225	1,221	1,200	1,222	**844**	(361)	0	3.4	0.0	(21.5)	1.0	(378)
2022	1,281	910	1,281	1,286	1,281	1,248	1,283	**885**	(371)	0	5.5	0.0	(32.7)	2.4	(396)
2023	1,312	932	1,312	1,322	1,312	1,268	1,317	**903**	(380)	0	9.2	0.0	(43.9)	5.0	(410)
2024	1,341	953	1,341	1,355	1,341	1,286	1,350	**921**	(388)	0	14.5	0.0	(55.2)	8.6	(420)
2025	1,363	968	1,363	1,385	1,363	1,299	1,376	**937**	(396)	0	21.3	0.0	(64.1)	12.2	(426)
2026	1,312	911	1,312	1,353	1,312	1,314	1,327	**968**	(402)	0	40.5	0.0	2.0	14.5	(345)
2027	1,329	923	1,329	1,386	1,329	1,332	1,349	**1,001**	(407)	0	56.9	0.0	2.1	19.0	(329)
2028	1,353	942	1,353	1,431	1,353	1,355	1,377	**1,047**	(411)	0	78.3	0.0	2.3	24.0	(307)
2029	1,368	953	1,368	1,476	1,368	1,371	1,398	**1,093**	(415)	0	108.1	0.0	2.4	29.4	(275)
2030	1,389	971	1,389	1,534	1,389	1,391	1,424	**1,154**	(418)	0	145.4	0.0	2.4	35.1	(235)
2031	1,409	988	1,409	1,602	1,409	1,412	1,453	**1,228**	(421)	0	193.2	0.0	2.5	44.3	(181)
2032	1,429	1,006	1,429	1,675	1,429	1,432	1,489	**1,314**	(423)	0	245.4	0.0	2.6	60.0	(115)
2033	1,449	1,024	1,449	1,752	1,449	1,452	1,531	**1,411**	(425)	0	302.4	0.0	2.6	81.8	(38)
2034	1,468	1,042	1,468	1,832	1,468	1,471	1,578	**1,517**	(427)	0	363.3	0.0	2.6	109.2	48
2035	1,490	1,061	1,490	1,916	1,490	1,492	1,631	**1,632**	(428)	0	426.7	0.0	2.7	141.4	143
2036	1,511	1,081	1,511	2,001	1,511	1,513	1,688	**1,752**	(430)	0	490.4	0.0	2.7	177.7	241
2037	1,537	1,106	1,537	2,089	1,537	1,539	1,754	**1,878**	(431)	0	552.6	0.0	2.7	217.2	342
2038	1,548	1,116	1,548	2,161	1,548	1,551	1,807	**1,990**	(432)	0	612.7	0.0	2.7	258.9	442
2039	1,562	1,128	1,562	2,237	1,562	1,565	1,864	**2,107**	(434)	0	674.5	0.0	2.7	301.7	545
2040	1,580	1,145	1,580	2,322	1,580	1,583	1,925	**2,235**	(435)	0	741.8	0.0	2.7	344.7	654
2041	1,596	1,159	1,596	2,378	1,596	1,599	1,983	**2,331**	(437)	0	782.3	0.0	2.7	386.9	735
2042	1,616	1,178	1,616	2,435	1,616	1,619	2,043	**2,427**	(438)	0	819.0	0.0	2.8	427.3	811
2043	1,634	1,195	1,634	2,486	1,634	1,637	2,100	**2,514**	(439)	0	851.6	0.0	2.8	465.0	880
2044	1,708	1,267	1,708	2,568	1,708	1,608	2,278	**2,598**	(441)	0	860.4	0.0	(99.7)	570.7	891
2045	1,722	1,279	1,722	2,606	1,722	1,622	2,327	**2,669**	(442)	0	884.9	0.0	(99.9)	605.2	948
2046	1,736	1,292	1,736	2,642	1,736	1,636	2,370	**2,732**	(444)	0	906.0	0.0	(99.9)	634.2	997
2047	1,757	1,312	1,757	2,681	1,757	1,657	2,414	**2,793**	(445)	0	923.9	0.0	(99.9)	657.4	1,036
2048	1,786	1,339	1,786	2,725	1,786	1,686	2,460	**2,853**	(447)	0	939.2	0.0	(99.9)	674.2	1,067
2049	1,795	1,347	1,795	2,747	1,795	1,695	2,480	**2,884**	(448)	0	952.2	0.0	(99.9)	684.4	1,089
2050	1,801	1,352	1,801	2,764	1,801	1,701	2,489	**2,903**	(449)	0	963.4	0.0	(99.9)	687.8	1,102

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Avg. last 15 yrs	1.1%	-0.9%	1.1%	1.1%	1.1%	1.0%	1.1%	-1.1%
Avg. last 10 yrs	1.8%	-0.5%	1.8%	1.9%	1.8%	1.7%	1.8%	-0.7%
Avg. last 5 yrs	2.9%	0.6%	2.9%	3.0%	2.9%	2.5%	2.9%	0.2%
Base 2021								
Avg. next 5 yrs	1.4%	1.1%	1.4%	2.0%	1.4%	1.8%	1.7%	2.8%
Avg. next 10 yrs	1.4%	1.4%	1.4%	2.7%	1.4%	1.6%	1.7%	3.8%
Avg. next 15 yrs	1.4%	1.5%	1.4%	3.3%	1.4%	1.6%	2.2%	5.0%
Avg. next 20 yrs	1.3%	1.5%	1.3%	3.4%	1.3%	1.4%	2.4%	5.2%
Avg. next 25 yrs	1.4%	1.6%	1.4%	3.1%	1.4%	1.2%	2.7%	4.8%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

SEMA Zone (Southeast Massachusetts)

SEMA
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	1,705		1,575		1,695		1,729		S
2007	1,522	-10.7%	1,589	0.9%	1,703	0.5%	1,735	0.4%	S
2008	1,549	1.8%	1,574	-0.9%	1,688	-0.9%	1,720	-0.9%	S
2009	1,456	-6.0%	1,588	0.9%	1,708	1.2%	1,742	1.3%	S
2010	1,586	8.9%	1,584	-0.3%	1,711	0.2%	1,747	0.3%	S
2011	1,658	4.5%	1,581	-0.2%	1,701	-0.6%	1,734	-0.7%	S
2012	1,551	-6.5%	1,587	0.4%	1,695	-0.3%	1,726	-0.5%	S
2013	1,659	7.0%	1,570	-1.1%	1,688	-0.4%	1,722	-0.2%	S
2014	1,417	-14.6%	1,585	0.9%	1,707	1.1%	1,742	1.2%	S
2015	1,473	4.0%	1,566	-1.1%	1,691	-1.0%	1,726	-0.9%	S
2016	1,519	3.1%	1,536	-2.0%	1,658	-1.9%	1,692	-1.9%	S
2017	1,419	-6.6%	1,523	-0.8%	1,645	-0.8%	1,679	-0.8%	S
2018	1,549	9.1%	1,494	-1.9%	1,613	-1.9%	1,647	-1.9%	S
2019	1,446	-6.6%	1,451	-2.8%	1,567	-2.9%	1,600	-2.9%	S
2020	1,506	4.1%	1,528	5.3%	1,651	5.4%	1,686	5.4%	S
2021	1,549	2.9%	1,454	-4.8%	1,591	-3.7%	1,629	-3.4%	S
2022	1,538	-0.7%	1,440	-1.0%	1,572	-1.1%	1,610	-1.2%	S
2023	-	-	1,427	-0.9%	1,560	-0.8%	1,598	-0.7%	S
2024	-	-	1,448	1.5%	1,587	1.7%	1,626	1.8%	S
2025	-	-	1,464	1.1%	1,604	1.1%	1,643	1.0%	S
2026	-	-	1,469	0.3%	1,609	0.3%	1,649	0.3%	S
2027	-	-	1,489	1.4%	1,631	1.3%	1,671	1.3%	S
2028	-	-	1,504	1.0%	1,647	1.0%	1,687	1.0%	S
2029	-	-	1,525	1.4%	1,663	1.0%	1,703	1.0%	S
2030	-	-	1,562	2.4%	1,698	2.1%	1,736	1.9%	S
2031	-	-	1,606	2.9%	1,743	2.7%	1,782	2.6%	S
2032	-	-	1,657	3.2%	1,795	3.0%	1,833	2.9%	S
2033	-	-	1,713	3.4%	1,851	3.1%	1,890	3.1%	S
2034	-	-	1,771	3.4%	1,910	3.2%	1,950	3.1%	S
2035	-	-	1,824	2.9%	1,963	2.8%	2,002	2.7%	S
2036	-	-	1,949	6.9%	2,031	3.5%	2,071	3.4%	W
2037	-	-	2,086	7.0%	2,140	5.4%	2,155	4.1%	W
2038	-		2,208	5.9%	2,263	5.7%	2,278	5.7%	W
2039	-		2,336	5.8%	2,391	5.7%	2,407	5.7%	W
2040	-		2,475	5.9%	2,530	5.8%	2,546	5.8%	W
2041	-		2,584	4.4%	2,640	4.3%	2,656	4.3%	W
2042	-		2,692	4.2%	2,749	4.1%	2,766	4.2%	W
2043	-		2,798	3.9%	2,857	3.9%	2,873	3.9%	W
2044	-		2,895	3.5%	2,955	3.4%	2,972	3.4%	W
2045	-		2,978	2.8%	3,038	2.8%	3,055	2.8%	W
2046	-		3,050	2.4%	3,110	2.4%	3,128	2.4%	W
2047	-		3,119	2.3%	3,180	2.2%	3,198	2.2%	W
2048	-		3,186	2.1%	3,248	2.1%	3,265	2.1%	W
2049	-		3,220	1.1%	3,282	1.1%	3,300	1.1%	W
2050	-		3,239	0.6%	3,302	0.6%	3,319	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.7%	-0.5%	-0.5%
Avg. last 10 yrs	-1.0%	-0.7%	-0.7%
Avg. last 5 yrs	-1.1%	-0.9%	-0.8%
Base 2022			
Avg. next 5 yrs	0.7%	0.7%	0.7%
Avg. next 10 yrs	1.4%	1.3%	1.3%
Avg. next 15 yrs	2.5%	2.1%	2.0%
Avg. next 20 yrs	3.2%	2.8%	2.7%
Avg. next 25 yrs	3.1%	2.9%	2.8%

*** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response***

SEMA
SUMMER Peaks **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	1,705		1,575		1,695		1,729		84.9
2007	1,522	-10.7%	1,589	0.9%	1,703	0.5%	1,735	0.4%	81.1
2008	1,549	1.8%	1,574	-0.9%	1,688	-0.9%	1,720	-0.9%	82.5
2009	1,456	-6.0%	1,588	0.9%	1,708	1.2%	1,742	1.3%	80.5
2010	1,586	8.9%	1,584	-0.3%	1,711	0.2%	1,747	0.3%	83.4
2011	1,658	4.5%	1,581	-0.2%	1,701	-0.6%	1,734	-0.7%	84.9
2012	1,551	-6.5%	1,587	0.4%	1,695	-0.3%	1,726	-0.5%	81.7
2013	1,659	7.0%	1,570	-1.1%	1,688	-0.4%	1,722	-0.2%	84.2
2014	1,417	-14.6%	1,585	0.9%	1,707	1.1%	1,742	1.2%	80.2
2015	1,473	4.0%	1,566	-1.1%	1,691	-1.0%	1,726	-0.9%	80.0
2016	1,519	3.1%	1,536	-2.0%	1,658	-1.9%	1,692	-1.9%	83.0
2017	1,419	-6.6%	1,523	-0.8%	1,645	-0.8%	1,679	-0.8%	81.9
2018	1,549	9.1%	1,494	-1.9%	1,613	-1.9%	1,647	-1.9%	83.5
2019	1,446	-6.6%	1,451	-2.8%	1,567	-2.9%	1,600	-2.9%	84.1
2020	1,506	4.1%	1,528	5.3%	1,651	5.4%	1,686	5.4%	82.0
2021	1,549	2.9%	1,454	-4.8%	1,591	-3.7%	1,629	-3.4%	84.5
2022	1,538	-0.7%	1,440	-1.0%	1,572	-1.1%	1,610	-1.2%	84.5
2023	-	-	1,427	-0.9%	1,560	-0.8%	1,598	-0.7%	-
2024	-	-	1,448	1.5%	1,587	1.7%	1,626	1.8%	-
2025	-	-	1,464	1.1%	1,604	1.1%	1,643	1.0%	-
2026	-	-	1,469	0.3%	1,609	0.3%	1,649	0.3%	-
2027	-	-	1,489	1.4%	1,631	1.3%	1,671	1.3%	-
2028	-	-	1,504	1.0%	1,647	1.0%	1,687	1.0%	-
2029	-	-	1,525	1.4%	1,663	1.0%	1,703	1.0%	-
2030	-	-	1,562	2.4%	1,698	2.1%	1,736	1.9%	-
2031	-	-	1,606	2.9%	1,743	2.7%	1,782	2.6%	-
2032	-	-	1,657	3.2%	1,795	3.0%	1,833	2.9%	-
2033	-	-	1,713	3.4%	1,851	3.1%	1,890	3.1%	-
2034	-	-	1,771	3.4%	1,910	3.2%	1,950	3.1%	-
2035	-	-	1,824	2.9%	1,963	2.8%	2,002	2.7%	-
2036	-	-	1,891	3.7%	2,031	3.5%	2,071	3.4%	-
2037	-	-	1,938	2.5%	2,079	2.3%	2,118	2.3%	-
2038	-		2,005	3.4%	2,146	3.2%	2,186	3.2%	-
2039	-		2,066	3.1%	2,208	2.9%	2,249	2.9%	-
2040	-		2,136	3.4%	2,279	3.2%	2,319	3.2%	-
2041	-		2,189	2.5%	2,333	2.3%	2,373	2.3%	-
2042	-		2,227	1.8%	2,372	1.7%	2,412	1.7%	-
2043	-		2,263	1.6%	2,407	1.5%	2,448	1.5%	-
2044	-		2,306	1.9%	2,451	1.8%	2,492	1.8%	-
2045	-		2,341	1.5%	2,487	1.5%	2,528	1.4%	-
2046	-		2,386	1.9%	2,533	1.9%	2,575	1.8%	-
2047	-		2,418	1.3%	2,566	1.3%	2,608	1.3%	-
2048	-		2,429	0.5%	2,577	0.4%	2,619	0.4%	-
2049	-		2,472	1.8%	2,621	1.7%	2,664	1.7%	-
2050	-		2,503	1.3%	2,653	1.2%	2,696	1.2%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.7%	-0.5%	-0.5%
Avg. last 10 yrs	-1.0%	-0.7%	-0.7%
Avg. last 5 yrs	-1.1%	-0.9%	-0.8%
Base 2022			
Avg. next 5 yrs	0.7%	0.7%	0.7%
Avg. next 10 yrs	1.4%	1.3%	1.3%
Avg. next 15 yrs	2.0%	1.9%	1.8%
Avg. next 20 yrs	2.2%	2.1%	2.0%
Avg. next 25 yrs	2.1%	2.0%	1.9%

WTHI

NORMAL	82.4
EXTREME 90/10	84.7
EXTREME 95/5	85.4

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

SEMA — SUMMER 50/50 Peaks (MW) (before & after DERs)

	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,608	1,575	1,608	1,608	1,608	1,608	1,608	**1,575**	(33)	(0)	0.0	0.0	0.0	0.0	(33)
2007	1,632	1,589	1,632	1,632	1,632	1,632	1,632	**1,589**	(43)	(0)	0.0	0.0	0.0	0.0	(44)
2008	1,627	1,574	1,627	1,627	1,627	1,627	1,627	**1,574**	(53)	(0)	0.0	0.0	0.0	0.0	(53)
2009	1,655	1,589	1,654	1,655	1,655	1,655	1,655	**1,588**	(65)	(1)	0.0	0.0	0.0	0.0	(66)
2010	1,665	1,584	1,664	1,665	1,665	1,665	1,665	**1,584**	(81)	(1)	0.0	0.0	0.0	0.0	(81)
2011	1,681	1,584	1,678	1,681	1,681	1,681	1,681	**1,581**	(97)	(3)	0.0	0.0	0.0	0.0	(100)
2012	1,711	1,595	1,703	1,711	1,711	1,711	1,711	**1,587**	(116)	(8)	0.0	0.0	0.0	0.0	(124)
2013	1,737	1,598	1,709	1,737	1,737	1,737	1,737	**1,570**	(139)	(28)	0.1	0.0	0.0	0.0	(167)
2014	1,785	1,619	1,751	1,785	1,785	1,785	1,785	**1,585**	(166)	(35)	0.1	0.0	0.0	0.0	(201)
2015	1,775	1,579	1,763	1,776	1,775	1,775	1,775	**1,566**	(196)	(13)	0.2	0.0	0.0	0.0	(209)
2016	1,842	1,611	1,766	1,842	1,842	1,842	1,842	**1,536**	(231)	(76)	0.2	(0.2)	0.0	0.0	(307)
2017	1,858	1,592	1,791	1,858	1,856	1,858	1,858	**1,523**	(266)	(67)	0.4	(2.4)	(0.1)	0.0	(335)
2018	1,839	1,537	1,807	1,840	1,828	1,839	1,839	**1,494**	(302)	(32)	0.8	(11.4)	(0.4)	0.0	(345)
2019	1,849	1,510	1,813	1,850	1,828	1,845	1,849	**1,451**	(339)	(35)	1.1	(20.7)	(3.7)	0.1	(397)
2020	1,971	1,596	1,931	1,972	1,951	1,960	1,971	**1,528**	(374)	(39)	1.5	(19.9)	(10.5)	0.2	(443)
2021	1,943	1,539	1,898	1,945	1,924	1,921	1,944	**1,454**	(404)	(45)	2.1	(19.5)	(22.5)	0.4	(489)
2022	2,178	1,755	1,917	2,180	2,158	2,140	2,179	**1,440**	(423)	(261)	2.3	(19.8)	(37.5)	0.8	(738)
2023	1,993	1,556	1,936	1,998	1,965	1,940	1,994	**1,427**	(436)	(57)	5.5	(27.2)	(52.6)	1.4	(566)
2024	2,090	1,641	1,837	2,095	2,075	2,155	2,092	**1,448**	(448)	(253)	5.8	(14.5)	65.4	2.5	(642)
2025	2,123	1,664	1,847	2,131	2,107	2,201	2,126	**1,464**	(459)	(275)	8.7	(15.4)	78.2	3.7	(659)
2026	2,144	1,676	1,846	2,156	2,128	2,232	2,149	**1,469**	(468)	(297)	12.6	(16.1)	88.4	5.1	(675)
2027	2,180	1,704	1,860	2,197	2,163	2,276	2,187	**1,489**	(475)	(320)	17.8	(16.7)	96.7	7.0	(690)
2028	2,209	1,727	1,866	2,234	2,192	2,312	2,218	**1,504**	(482)	(343)	24.6	(17.5)	103.3	9.2	(705)
2029	2,102	1,614	2,090	2,162	2,065	1,989	2,112	**1,525**	(487)	(12)	60.5	(36.7)	(112.3)	10.5	(577)
2030	2,126	1,634	2,114	2,208	2,088	2,009	2,139	**1,562**	(492)	(12)	82.2	(38.2)	(116.7)	12.8	(564)
2031	2,150	1,654	2,137	2,260	2,111	2,030	2,165	**1,606**	(496)	(13)	109.8	(39.3)	(120.1)	15.5	(543)
2032	2,173	1,674	2,159	2,315	2,133	2,051	2,192	**1,657**	(499)	(14)	141.7	(40.4)	(122.9)	18.8	(516)
2033	2,197	1,695	2,182	2,374	2,156	2,072	2,220	**1,713**	(502)	(15)	176.7	(41.6)	(125.2)	22.8	(484)
2034	2,220	1,715	2,204	2,434	2,177	2,093	2,247	**1,771**	(505)	(16)	214.3	(42.7)	(127.0)	27.4	(449)
2035	2,233	1,726	2,216	2,487	2,189	2,105	2,265	**1,824**	(507)	(17)	254.1	(43.9)	(128.4)	32.3	(409)
2036	2,260	1,751	2,242	2,555	2,214	2,130	2,297	**1,891**	(509)	(18)	294.9	(45.2)	(129.5)	37.6	(369)
2037	2,267	1,756	2,248	2,601	2,220	2,136	2,310	**1,938**	(511)	(19)	334.8	(46.5)	(130.4)	43.0	(328)
2038	2,294	1,782	2,275	2,668	2,246	2,163	2,343	**2,005**	(513)	(19)	373.5	(48.0)	(131.2)	48.5	(289)
2039	2,316	1,801	2,295	2,729	2,266	2,184	2,369	**2,066**	(515)	(20)	413.2	(49.4)	(131.8)	53.8	(249)
2040	2,342	1,826	2,321	2,798	2,292	2,210	2,401	**2,136**	(517)	(22)	456.1	(50.4)	(132.3)	58.8	(206)
2041	2,367	1,849	2,345	2,850	2,316	2,235	2,431	**2,189**	(518)	(23)	482.9	(51.2)	(132.7)	63.6	(178)
2042	2,381	1,861	2,358	2,888	2,329	2,248	2,449	**2,227**	(520)	(23)	507.1	(51.8)	(133.0)	67.9	(154)
2043	2,394	1,872	2,370	2,923	2,342	2,261	2,466	**2,263**	(522)	(24)	528.7	(52.5)	(133.2)	71.7	(132)
2044	2,419	1,895	2,394	2,967	2,366	2,285	2,494	**2,306**	(524)	(25)	547.9	(53.1)	(133.5)	74.9	(113)
2045	2,438	1,912	2,412	3,002	2,384	2,304	2,515	**2,341**	(526)	(25)	564.6	(53.8)	(133.7)	77.7	(97)
2046	2,470	1,942	2,444	3,049	2,415	2,336	2,550	**2,386**	(528)	(26)	579.1	(54.6)	(133.9)	79.9	(84)
2047	2,491	1,961	2,465	3,082	2,436	2,357	2,573	**2,418**	(530)	(26)	591.4	(55.4)	(133.9)	81.6	(73)
2048	2,494	1,962	2,467	3,096	2,437	2,360	2,576	**2,429**	(532)	(27)	602.0	(56.2)	(133.9)	82.8	(64)
2049	2,530	1,996	2,503	3,141	2,473	2,396	2,613	**2,472**	(534)	(27)	610.9	(56.9)	(133.9)	83.6	(57)
2050	2,556	2,020	2,528	3,174	2,498	2,422	2,640	**2,503**	(536)	(27)	618.6	(57.7)	(133.9)	84.0	(52)

Avg. last 15 yrs	1.9%	0.7%	1.1%	1.9%	1.9%	1.8%	1.9%	-0.7%
Avg. last 10 yrs	2.4%	1.0%	1.2%	2.5%	2.3%	2.3%	2.4%	-1.0%
Avg. last 5 yrs	3.2%	2.0%	1.4%	3.2%	3.1%	2.9%	3.2%	-1.1%
Base 2022								
Avg. next 5 yrs	0.0%	-0.6%	-0.6%	0.2%	0.0%	1.2%	0.1%	0.7%
Avg. next 10 yrs	0.0%	-0.5%	1.2%	0.6%	-0.1%	-0.4%	0.1%	1.4%
Avg. next 15 yrs	0.3%	0.0%	1.1%	1.2%	0.2%	0.0%	0.4%	2.0%
Avg. next 20 yrs	0.4%	0.3%	1.0%	1.4%	0.4%	0.2%	0.6%	2.2%
Avg. next 25 yrs	0.5%	0.4%	1.0%	1.4%	0.5%	0.4%	0.7%	2.1%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

SEMA
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	1,194		1,193		1,230		1,240		46.9
2007	1,181	-1.1%	1,165	-2.4%	1,200	-2.4%	1,209	-2.5%	46.7
2008	1,138	-3.7%	1,134	-2.6%	1,172	-2.3%	1,182	-2.2%	47.3
2009	1,143	0.4%	1,182	4.2%	1,223	4.3%	1,234	4.4%	36.7
2010	1,151	0.8%	1,109	-6.2%	1,150	-5.9%	1,162	-5.8%	54.9
2011	1,084	-5.8%	1,118	0.8%	1,158	0.7%	1,169	0.6%	45.4
2012	1,165	7.4%	1,147	2.6%	1,184	2.3%	1,195	2.2%	49.8
2013	1,218	4.6%	1,228	7.1%	1,269	7.2%	1,281	7.2%	44.4
2014	1,132	-7.0%	1,112	-9.5%	1,150	-9.4%	1,160	-9.4%	52.4
2015	1,058	-6.6%	1,082	-2.7%	1,118	-2.8%	1,128	-2.8%	42.3
2016	1,100	4.0%	1,095	1.2%	1,141	2.1%	1,154	2.3%	46.0
2017	1,155	4.9%	1,108	1.2%	1,162	1.9%	1,178	2.1%	52.6
2018	1,138	-1.4%	1,107	0.0%	1,153	-0.8%	1,166	-1.0%	51.3
2019	1,016	-10.7%	1,043	-5.8%	1,085	-5.8%	1,097	-5.8%	41.7
2020	1,042	2.5%	1,102	5.6%	1,147	5.7%	1,160	5.7%	39.7
2021	1,061	1.9%	1,053	-4.4%	1,095	-4.5%	1,107	-4.6%	45.1
2022	-	-	1,075	2.1%	1,122	2.5%	1,136	2.6%	-
2023		-	1,081	0.5%	1,129	0.6%	1,143	0.6%	
2024		-	1,096	1.4%	1,145	1.4%	1,159	1.4%	
2025	-	-	1,110	1.3%	1,160	1.3%	1,174	1.3%	-
2026	-	-	1,135	2.2%	1,186	2.2%	1,200	2.2%	-
2027	-	-	1,166	2.7%	1,214	2.4%	1,227	2.3%	-
2028	-	-	1,213	4.0%	1,261	3.9%	1,275	3.9%	-
2029	-	-	1,260	3.8%	1,308	3.7%	1,322	3.7%	-
2030	-	-	1,320	4.8%	1,370	4.7%	1,384	4.6%	-
2031	-	-	1,395	5.7%	1,445	5.5%	1,459	5.5%	-
2032	-	-	1,483	6.3%	1,534	6.1%	1,548	6.1%	-
2033	-	-	1,585	6.8%	1,636	6.6%	1,651	6.6%	-
2034	-	-	1,697	7.1%	1,749	6.9%	1,763	6.8%	-
2035	-	-	1,820	7.3%	1,872	7.1%	1,887	7.0%	-
2036	-	-	1,949	7.1%	2,002	6.9%	2,017	6.9%	-
2037	-		2,086	7.0%	2,140	6.9%	2,155	6.8%	-
2038	-		2,208	5.9%	2,263	5.7%	2,278	5.7%	-
2039	-		2,336	5.8%	2,391	5.7%	2,407	5.7%	-
2040	-		2,475	5.9%	2,530	5.8%	2,546	5.8%	-
2041	-		2,584	4.4%	2,640	4.3%	2,656	4.3%	-
2042	-		2,692	4.2%	2,749	4.1%	2,766	4.2%	-
2043	-		2,798	3.9%	2,857	3.9%	2,873	3.9%	-
2044	-		2,895	3.5%	2,955	3.4%	2,972	3.4%	-
2045	-		2,978	2.8%	3,038	2.8%	3,055	2.8%	-
2046	-		3,050	2.4%	3,110	2.4%	3,128	2.4%	-
2047	-		3,119	2.3%	3,180	2.2%	3,198	2.2%	-
2048	-		3,186	2.1%	3,248	2.1%	3,265	2.1%	-
2049	-		3,220	1.1%	3,282	1.1%	3,300	1.1%	-
2050	-		3,239	0.6%	3,302	0.6%	3,319	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.8%	-0.8%	-0.8%
Avg. last 10 yrs	-0.6%	-0.6%	-0.5%
Avg. last 5 yrs	-0.8%	-0.8%	-0.8%
Base 2021			
Avg. next 5 yrs	1.5%	1.6%	1.6%
Avg. next 10 yrs	2.9%	2.8%	2.8%
Avg. next 15 yrs	4.2%	4.1%	4.1%
Avg. next 20 yrs	4.6%	4.5%	4.5%
Avg. next 25 yrs	4.3%	4.3%	4.2%

HDD_wtd

NORMAL	46.3
EXTREME 90/10	53.6
EXTREME 95/5	55.7

*** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

SEMA — WINTER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
	SYSTEM PEAK								DER IMPACTS						
2006	1,249	1,193	1,249	1,249	1,249	1,249	1,249	**1,193**	(56)	0	0.0	0.0	0.0	0.0	(56)
2007	1,238	1,165	1,238	1,238	1,238	1,238	1,238	**1,165**	(73)	0	0.0	0.0	0.0	0.0	(73)
2008	1,218	1,134	1,218	1,218	1,218	1,218	1,218	**1,134**	(84)	0	0.0	0.0	0.0	0.0	(84)
2009	1,285	1,182	1,285	1,285	1,285	1,285	1,285	**1,182**	(103)	0	0.0	0.0	0.0	0.0	(103)
2010	1,229	1,109	1,229	1,229	1,229	1,229	1,229	**1,109**	(120)	0	0.0	0.0	0.0	0.0	(120)
2011	1,257	1,118	1,257	1,257	1,257	1,257	1,257	**1,118**	(139)	0	0.0	0.0	0.0	0.0	(139)
2012	1,306	1,147	1,306	1,306	1,306	1,306	1,306	**1,147**	(159)	0	0.1	0.0	0.0	0.0	(159)
2013	1,416	1,228	1,416	1,416	1,416	1,416	1,416	**1,228**	(188)	0	0.1	0.0	0.0	0.0	(187)
2014	1,330	1,112	1,330	1,330	1,330	1,330	1,330	**1,112**	(218)	0	0.3	0.0	0.0	0.0	(217)
2015	1,333	1,082	1,333	1,333	1,333	1,333	1,333	**1,082**	(251)	0	0.4	0.0	0.0	0.0	(251)
2016	1,381	1,094	1,381	1,381	1,381	1,381	1,381	**1,095**	(286)	0	0.5	0.0	0.0	0.0	(286)
2017	1,429	1,107	1,429	1,430	1,429	1,429	1,429	**1,108**	(322)	0	0.8	0.0	(0.1)	0.0	(321)
2018	1,467	1,107	1,467	1,469	1,467	1,467	1,467	**1,107**	(361)	0	1.1	0.0	(0.6)	0.0	(360)
2019	1,446	1,047	1,446	1,447	1,446	1,440	1,446	**1,043**	(399)	0	1.9	0.0	(6.0)	0.2	(403)
2020	1,550	1,113	1,550	1,552	1,550	1,536	1,551	**1,102**	(437)	0	2.0	0.0	(13.8)	0.7	(448)
2021	1,539	1,078	1,539	1,542	1,539	1,510	1,540	**1,053**	(461)	0	3.0	0.0	(29.0)	1.4	(486)
2022	1,585	1,111	1,585	1,590	1,585	1,541	1,588	**1,075**	(474)	0	4.9	0.0	(44.2)	3.2	(510)
2023	1,610	1,125	1,610	1,619	1,610	1,551	1,617	**1,081**	(485)	0	8.4	0.0	(59.3)	6.8	(530)
2024	1,642	1,146	1,642	1,655	1,642	1,567	1,653	**1,096**	(496)	0	13.2	0.0	(74.5)	11.6	(546)
2025	1,666	1,161	1,666	1,686	1,666	1,580	1,683	**1,110**	(505)	0	19.5	0.0	(86.5)	16.5	(556)
2026	1,694	1,181	1,694	1,722	1,694	1,598	1,717	**1,135**	(513)	0	28.0	0.0	(96.1)	22.4	(559)
2027	1,605	1,085	1,605	1,657	1,605	1,608	1,631	**1,166**	(520)	0	52.3	0.0	2.9	25.7	(439)
2028	1,631	1,105	1,631	1,703	1,631	1,634	1,663	**1,213**	(525)	0	72.0	0.0	3.1	32.4	(418)
2029	1,647	1,117	1,647	1,747	1,647	1,650	1,687	**1,260**	(530)	0	99.4	0.0	3.2	39.7	(388)
2030	1,670	1,136	1,670	1,804	1,670	1,673	1,717	**1,320**	(534)	0	133.8	0.0	3.3	47.4	(349)
2031	1,692	1,154	1,692	1,869	1,692	1,695	1,751	**1,395**	(537)	0	177.9	0.0	3.4	59.8	(296)
2032	1,713	1,173	1,713	1,939	1,713	1,717	1,794	**1,483**	(540)	0	226.0	0.0	3.5	80.9	(230)
2033	1,735	1,192	1,735	2,014	1,735	1,739	1,845	**1,585**	(543)	0	278.6	0.0	3.5	110.4	(150)
2034	1,756	1,211	1,756	2,091	1,756	1,760	1,903	**1,697**	(545)	0	334.8	0.0	3.6	147.3	(59)
2035	1,779	1,232	1,779	2,172	1,779	1,783	1,970	**1,820**	(547)	0	393.2	0.0	3.6	190.9	41
2036	1,802	1,254	1,802	2,254	1,802	1,806	2,042	**1,949**	(549)	0	451.9	0.0	3.6	239.9	147
2037	1,830	1,280	1,830	2,339	1,830	1,834	2,123	**2,086**	(550)	0	509.3	0.0	3.7	293.1	256
2038	1,843	1,291	1,843	2,407	1,843	1,846	2,192	**2,208**	(552)	0	564.7	0.0	3.7	349.4	366
2039	1,858	1,304	1,858	2,480	1,858	1,862	2,265	**2,336**	(554)	0	621.6	0.0	3.7	407.2	479
2040	1,878	1,322	1,878	2,562	1,878	1,882	2,343	**2,475**	(556)	0	683.7	0.0	3.7	465.2	597
2041	1,895	1,337	1,895	2,616	1,895	1,899	2,417	**2,584**	(558)	0	721.0	0.0	3.7	522.1	689
2042	1,917	1,357	1,917	2,671	1,917	1,920	2,493	**2,692**	(559)	0	754.8	0.0	3.7	576.7	776
2043	2,009	1,448	2,009	2,776	2,009	1,874	2,726	**2,798**	(561)	0	767.1	0.0	(134.3)	717.3	789
2044	2,030	1,467	2,030	2,823	2,030	1,895	2,800	**2,895**	(563)	0	793.0	0.0	(134.5)	770.2	866
2045	2,045	1,480	2,045	2,860	2,045	1,910	2,862	**2,978**	(565)	0	815.6	0.0	(134.8)	816.7	933
2046	2,060	1,494	2,060	2,895	2,060	1,926	2,916	**3,050**	(567)	0	835.0	0.0	(134.8)	856.0	990
2047	2,084	1,515	2,084	2,935	2,084	1,949	2,971	**3,119**	(568)	0	851.6	0.0	(134.8)	887.2	1,036
2048	2,115	1,545	2,115	2,981	2,115	1,980	3,025	**3,186**	(570)	0	865.7	0.0	(134.8)	909.9	1,071
2049	2,125	1,553	2,125	3,003	2,125	1,990	3,049	**3,220**	(572)	0	877.7	0.0	(134.8)	923.7	1,095
2050	2,132	1,558	2,132	3,020	2,132	1,997	3,060	**3,239**	(574)	0	887.9	0.0	(134.8)	928.3	1,108

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
	-							
Avg. last 15 yrs	1.4%	-0.7%	1.4%	1.4%	1.4%	1.3%	1.4%	-0.8%
Avg. last 10 yrs	2.0%	-0.4%	2.0%	2.1%	2.0%	1.9%	2.1%	-0.6%
Avg. last 5 yrs	2.2%	-0.3%	2.2%	2.2%	2.2%	1.8%	2.2%	-0.8%
Base 2021								
Avg. next 5 yrs	1.9%	1.9%	1.9%	2.2%	1.9%	1.1%	2.2%	1.5%
Avg. next 10 yrs	1.0%	0.7%	1.0%	1.9%	1.0%	1.2%	1.3%	2.9%
Avg. next 15 yrs	1.1%	1.0%	1.1%	2.6%	1.1%	1.2%	1.9%	4.2%
Avg. next 20 yrs	0.8%	0.8%	0.8%	1.9%	0.8%	0.9%	1.4%	3.1%
Avg. next 25 yrs	1.2%	1.3%	1.2%	2.6%	1.2%	1.0%	2.6%	4.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

WCMA Zone (Western/Central Massachusetts)

WCMA
Annual Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	2,229		2,092		2,197		2,226		S
2007	2,088	-6.3%	2,104	0.5%	2,206	0.4%	2,235	0.4%	S
2008	2,167	3.8%	2,107	0.2%	2,204	-0.1%	2,232	-0.1%	S
2009	1,984	-8.4%	2,064	-2.0%	2,161	-1.9%	2,189	-1.9%	S
2010	2,137	7.7%	2,089	1.2%	2,192	1.4%	2,221	1.5%	S
2011	2,182	2.1%	2,112	1.1%	2,212	0.9%	2,240	0.9%	S
2012	2,073	-5.0%	2,078	-1.6%	2,178	-1.5%	2,207	-1.5%	S
2013	2,165	4.5%	2,059	-0.9%	2,161	-0.8%	2,190	-0.8%	S
2014	1,935	-10.6%	2,049	-0.5%	2,154	-0.3%	2,184	-0.3%	S
2015	1,935	0.0%	2,034	-0.7%	2,139	-0.7%	2,168	-0.7%	S
2016	1,983	2.4%	2,029	-0.3%	2,129	-0.5%	2,157	-0.5%	S
2017	1,879	-5.2%	1,998	-1.5%	2,117	-0.5%	2,151	-0.3%	S
2018	2,026	7.8%	1,986	-0.6%	2,086	-1.5%	2,115	-1.7%	S
2019	1,882	-7.1%	1,929	-2.9%	2,025	-2.9%	2,053	-2.9%	S
2020	1,904	1.2%	1,946	0.9%	2,060	1.7%	2,092	1.9%	S
2021	1,978	3.9%	1,925	-1.0%	2,021	-1.9%	2,048	-2.1%	S
2022	2,006	1.4%	1,960	1.8%	2,070	2.4%	2,101	2.6%	S
2023	-	-	1,967	0.4%	2,070	0.0%	2,099	-0.1%	S
2024	-	-	1,992	1.3%	2,095	1.2%	2,124	1.2%	S
2025	-	-	2,023	1.5%	2,125	1.5%	2,155	1.5%	S
2026	-	-	2,045	1.1%	2,148	1.1%	2,177	1.1%	S
2027	-	-	2,090	2.2%	2,193	2.1%	2,222	2.1%	S
2028	-	-	2,133	2.1%	2,237	2.0%	2,266	2.0%	S
2029	-	-	2,183	2.3%	2,287	2.2%	2,316	2.2%	S
2030	-	-	2,239	2.6%	2,343	2.5%	2,372	2.4%	S
2031	-	-	2,305	2.9%	2,409	2.8%	2,438	2.8%	S
2032	-	-	2,378	3.2%	2,482	3.1%	2,512	3.0%	S
2033	-	-	2,458	3.3%	2,562	3.2%	2,592	3.2%	S
2034	-	-	2,541	3.4%	2,645	3.2%	2,675	3.2%	S
2035	-	-	2,617	3.0%	2,721	2.9%	2,751	2.8%	S
2036	-	-	2,754	5.2%	2,830	4.0%	2,851	3.7%	W
2037	-	-	2,939	6.7%	3,016	6.6%	3,038	6.5%	W
2038	-		3,105	5.7%	3,183	5.5%	3,205	5.5%	W
2039	-		3,279	5.6%	3,358	5.5%	3,380	5.5%	W
2040	-		3,467	5.7%	3,546	5.6%	3,569	5.6%	W
2041	-		3,614	4.2%	3,694	4.2%	3,717	4.2%	W
2042	-		3,759	4.0%	3,840	4.0%	3,863	3.9%	W
2043	-		3,892	3.5%	3,974	3.5%	3,998	3.5%	W
2044	-		4,021	3.3%	4,105	3.3%	4,129	3.3%	W
2045	-		4,130	2.7%	4,216	2.7%	4,240	2.7%	W
2046	-		4,227	2.3%	4,313	2.3%	4,337	2.3%	W
2047	-		4,319	2.2%	4,406	2.1%	4,430	2.1%	W
2048	-		4,406	2.0%	4,494	2.0%	4,519	2.0%	W
2049	-		4,451	1.0%	4,540	1.0%	4,565	1.0%	W
2050	-		4,477	0.6%	4,567	0.6%	4,592	0.6%	W

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.5%	-0.4%	-0.4%
Avg. last 10 yrs	-0.6%	-0.5%	-0.5%
Avg. last 5 yrs	-0.4%	-0.4%	-0.5%
BASE 2022			
Avg. next 5 yrs	1.3%	1.2%	1.1%
Avg. next 10 yrs	2.0%	1.8%	1.8%
Avg. next 15 yrs	2.7%	2.5%	2.5%
Avg. next 20 yrs	3.3%	3.1%	3.1%
Avg. next 25 yrs	3.2%	3.1%	3.0%

*** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response**

WCMA
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2006	2,229		2,092		2,197		2,226		82.7
2007	2,088	-6.3%	2,104	0.5%	2,206	0.4%	2,235	0.4%	80.7
2008	2,167	3.8%	2,107	0.2%	2,204	-0.1%	2,232	-0.1%	81.6
2009	1,984	-8.4%	2,064	-2.0%	2,161	-1.9%	2,189	-1.9%	79.2
2010	2,137	7.7%	2,089	1.2%	2,192	1.4%	2,221	1.5%	81.3
2011	2,182	2.1%	2,112	1.1%	2,212	0.9%	2,240	0.9%	82.5
2012	2,073	-5.0%	2,078	-1.6%	2,178	-1.5%	2,207	-1.5%	80.5
2013	2,165	4.5%	2,059	-0.9%	2,161	-0.8%	2,190	-0.8%	82.3
2014	1,935	-10.6%	2,049	-0.5%	2,154	-0.3%	2,184	-0.3%	79.5
2015	1,935	0.0%	2,034	-0.7%	2,139	-0.7%	2,168	-0.7%	79.4
2016	1,983	2.4%	2,029	-0.3%	2,129	-0.5%	2,157	-0.5%	80.5
2017	1,879	-5.2%	1,998	-1.5%	2,117	-0.5%	2,151	-0.3%	79.4
2018	2,026	7.8%	1,986	-0.6%	2,086	-1.5%	2,115	-1.7%	81.2
2019	1,882	-7.1%	1,929	-2.9%	2,025	-2.9%	2,053	-2.9%	79.8
2020	1,904	1.2%	1,946	0.9%	2,060	1.7%	2,092	1.9%	80.0
2021	1,978	3.9%	1,925	-1.0%	2,021	-1.9%	2,048	-2.1%	82.1
2022	2,006	1.4%	1,960	1.8%	2,070	2.4%	2,101	2.6%	80.0
2023	-	-	1,967	0.4%	2,070	0.0%	2,099	-0.1%	-
2024	-	-	1,992	1.3%	2,095	1.2%	2,124	1.2%	-
2025	-	-	2,023	1.5%	2,125	1.5%	2,155	1.5%	-
2026	-	-	2,045	1.1%	2,148	1.1%	2,177	1.1%	-
2027	-	-	2,090	2.2%	2,193	2.1%	2,222	2.1%	-
2028	-	-	2,133	2.1%	2,237	2.0%	2,266	2.0%	-
2029	-	-	2,183	2.3%	2,287	2.2%	2,316	2.2%	-
2030	-	-	2,239	2.6%	2,343	2.5%	2,372	2.4%	-
2031	-	-	2,305	2.9%	2,409	2.8%	2,438	2.8%	-
2032	-	-	2,378	3.2%	2,482	3.1%	2,512	3.0%	-
2033	-	-	2,458	3.3%	2,562	3.2%	2,592	3.2%	-
2034	-	-	2,541	3.4%	2,645	3.2%	2,675	3.2%	-
2035	-	-	2,617	3.0%	2,721	2.9%	2,751	2.8%	-
2036	-	-	2,711	3.6%	2,815	3.5%	2,845	3.4%	-
2037	-	-	2,780	2.6%	2,885	2.5%	2,915	2.4%	-
2038	-		2,872	3.3%	2,977	3.2%	3,007	3.2%	-
2039	-		2,958	3.0%	3,063	2.9%	3,093	2.9%	-
2040	-		3,055	3.3%	3,160	3.2%	3,190	3.1%	-
2041	-		3,126	2.3%	3,232	2.3%	3,261	2.2%	-
2042	-		3,180	1.7%	3,285	1.7%	3,315	1.6%	-
2043	-		3,229	1.5%	3,334	1.5%	3,364	1.5%	-
2044	-		3,286	1.8%	3,392	1.7%	3,422	1.7%	-
2045	-		3,333	1.4%	3,439	1.4%	3,469	1.4%	-
2046	-		3,391	1.7%	3,497	1.7%	3,527	1.7%	-
2047	-		3,433	1.2%	3,539	1.2%	3,569	1.2%	-
2048	-		3,449	0.5%	3,555	0.5%	3,585	0.5%	-
2049	-		3,502	1.5%	3,609	1.5%	3,639	1.5%	-
2050	-		3,541	1.1%	3,648	1.1%	3,678	1.1%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.5%	-0.4%	-0.4%
Avg. last 10 yrs	-0.6%	-0.5%	-0.5%
Avg. last 5 yrs	-0.4%	-0.4%	-0.5%
BASE 2022			
Avg. next 5 yrs	1.3%	1.2%	1.1%
Avg. next 10 yrs	2.0%	1.8%	1.8%
Avg. next 15 yrs	2.4%	2.2%	2.2%
Avg. next 20 yrs	1.8%	1.7%	1.6%
Avg. next 25 yrs	2.0%	1.9%	1.8%

WTHI

NORMAL	80.6
EXTREME 90/10	82.2
EXTREME 95/5	82.7

impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response

WCMA — SUMMER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
	SYSTEM PEAK								DER IMPACTS						
2006	2,138	2,092	2,138	2,138	2,138	2,138	2,138	**2,092**	(45)	(0)	0.0	0.0	0.0	0.0	(46)
2007	2,163	2,104	2,162	2,163	2,163	2,163	2,163	**2,104**	(59)	(0)	0.0	0.0	0.0	0.0	(59)
2008	2,180	2,108	2,180	2,180	2,180	2,180	2,180	**2,107**	(73)	(0)	0.0	0.0	0.0	0.0	(73)
2009	2,155	2,066	2,154	2,155	2,155	2,155	2,155	**2,064**	(90)	(1)	0.0	0.0	0.0	0.0	(91)
2010	2,202	2,092	2,199	2,202	2,202	2,202	2,202	**2,089**	(110)	(3)	0.0	0.0	0.0	0.0	(113)
2011	2,252	2,120	2,245	2,252	2,252	2,252	2,252	**2,112**	(132)	(7)	0.0	0.0	0.0	0.0	(140)
2012	2,243	2,086	2,235	2,243	2,243	2,243	2,243	**2,078**	(157)	(8)	0.0	0.0	0.0	0.0	(165)
2013	2,288	2,100	2,247	2,288	2,288	2,288	2,288	**2,059**	(188)	(41)	0.1	0.0	0.0	0.0	(228)
2014	2,355	2,131	2,273	2,356	2,355	2,355	2,355	**2,049**	(224)	(83)	0.2	0.0	0.0	0.0	(306)
2015	2,362	2,098	2,297	2,362	2,362	2,362	2,362	**2,034**	(264)	(64)	0.3	0.0	0.0	0.0	(328)
2016	2,529	2,220	2,337	2,529	2,528	2,529	2,529	**2,029**	(309)	(192)	0.4	(0.2)	0.0	0.0	(500)
2017	2,485	2,130	2,356	2,486	2,482	2,485	2,485	**1,998**	(355)	(129)	0.6	(3.2)	(0.1)	0.0	(487)
2018	2,463	2,061	2,402	2,464	2,448	2,463	2,463	**1,986**	(403)	(61)	1.3	(15.0)	(0.5)	0.0	(478)
2019	2,418	1,968	2,409	2,420	2,391	2,413	2,418	**1,929**	(450)	(9)	2.2	(27.3)	(5.0)	0.1	(489)
2020	2,561	2,064	2,479	2,563	2,535	2,547	2,561	**1,946**	(496)	(82)	2.4	(26.2)	(13.8)	0.2	(615)
2021	2,609	2,074	2,512	2,612	2,583	2,579	2,609	**1,925**	(535)	(97)	3.3	(25.8)	(29.7)	0.5	(683)
2022	2,707	2,149	2,597	2,712	2,672	2,658	2,708	**1,960**	(558)	(110)	5.0	(34.8)	(49.5)	1.0	(747)
2023	2,556	1,981	2,556	2,566	2,529	2,558	2,558	**1,967**	(575)	0	9.9	(26.9)	1.8	1.5	(589)
2024	2,591	2,000	2,591	2,606	2,562	2,593	2,593	**1,992**	(591)	0	15.6	(28.6)	2.4	2.6	(599)
2025	2,627	2,023	2,627	2,650	2,597	2,630	2,631	**2,023**	(604)	0	23.1	(30.4)	2.8	3.9	(605)
2026	2,651	2,035	2,651	2,684	2,619	2,654	2,656	**2,045**	(616)	0	33.2	(31.8)	3.2	5.4	(606)
2027	2,691	2,065	2,691	2,738	2,658	2,694	2,698	**2,090**	(626)	0	46.8	(33.1)	3.5	7.4	(601)
2028	2,724	2,090	2,724	2,788	2,689	2,727	2,733	**2,133**	(634)	0	64.8	(34.7)	3.7	9.7	(590)
2029	2,755	2,114	2,755	2,844	2,718	2,759	2,767	**2,183**	(641)	0	89.2	(36.3)	3.9	12.2	(572)
2030	2,784	2,137	2,784	2,905	2,746	2,788	2,799	**2,239**	(647)	0	121.1	(37.7)	4.1	15.0	(544)
2031	2,812	2,160	2,812	2,973	2,773	2,816	2,830	**2,305**	(652)	0	161.5	(38.9)	4.2	18.2	(507)
2032	2,840	2,184	2,840	3,048	2,800	2,844	2,862	**2,378**	(656)	0	208.3	(39.9)	4.3	22.1	(461)
2033	2,868	2,208	2,868	3,128	2,827	2,872	2,895	**2,458**	(660)	0	259.6	(41.1)	4.4	26.7	(410)
2034	2,895	2,232	2,895	3,210	2,853	2,899	2,927	**2,541**	(663)	0	314.8	(42.2)	4.4	32.0	(354)
2035	2,910	2,245	2,910	3,284	2,867	2,915	2,948	**2,617**	(666)	0	373.2	(43.4)	4.5	37.9	(294)
2036	2,942	2,274	2,942	3,375	2,897	2,946	2,986	**2,711**	(668)	0	433.1	(44.7)	4.5	44.0	(231)
2037	2,950	2,280	2,950	3,442	2,904	2,955	3,001	**2,780**	(671)	0	491.6	(46.0)	4.6	50.4	(170)
2038	2,983	2,310	2,983	3,531	2,935	2,987	3,040	**2,872**	(673)	0	548.5	(47.4)	4.6	56.8	(111)
2039	3,008	2,333	3,008	3,615	2,959	3,013	3,071	**2,958**	(676)	0	606.8	(48.8)	4.6	63.0	(50)
2040	3,040	2,361	3,040	3,709	2,990	3,044	3,108	**3,055**	(678)	0	669.7	(49.8)	4.6	68.9	15
2041	3,069	2,389	3,069	3,778	3,019	3,074	3,144	**3,126**	(681)	0	709.0	(50.6)	4.6	74.5	57
2042	3,086	2,403	3,086	3,830	3,035	3,090	3,165	**3,180**	(683)	0	744.3	(51.2)	4.7	79.5	94
2043	3,101	2,416	3,101	3,877	3,050	3,106	3,185	**3,229**	(686)	0	775.8	(51.9)	4.7	84.0	127
2044	3,130	2,442	3,130	3,934	3,078	3,135	3,218	**3,286**	(688)	0	803.7	(52.5)	4.7	87.8	156
2045	3,153	2,463	3,153	3,981	3,100	3,158	3,244	**3,333**	(690)	0	827.9	(53.2)	4.7	91.0	180
2046	3,191	2,498	3,191	4,040	3,137	3,196	3,285	**3,391**	(693)	0	848.8	(54.0)	4.7	93.6	200
2047	3,216	2,521	3,216	4,083	3,161	3,221	3,312	**3,433**	(695)	0	866.6	(54.7)	4.7	95.6	217
2048	3,219	2,521	3,219	4,101	3,163	3,224	3,316	**3,449**	(698)	0	881.7	(55.5)	4.7	97.0	230
2049	3,262	2,562	3,262	4,156	3,206	3,267	3,360	**3,502**	(700)	0	894.5	(56.3)	4.7	97.9	240
2050	3,293	2,590	3,293	4,198	3,236	3,297	3,391	**3,541**	(703)	0	905.3	(57.1)	4.7	98.4	248

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
Avg. last 15 yrs	1.5%	0.1%	1.2%	1.5%	1.4%	1.4%	1.5%	-0.5%
Avg. last 10 yrs	1.9%	0.3%	1.5%	1.9%	1.8%	1.7%	1.9%	-0.6%
Avg. last 5 yrs	1.7%	0.2%	2.0%	1.8%	1.5%	1.4%	1.7%	-0.4%
BASE 2022								
Avg. next 5 yrs	-0.1%	-0.8%	0.7%	0.2%	-0.1%	0.3%	-0.1%	1.3%
Avg. next 10 yrs	0.5%	0.2%	0.9%	1.2%	0.5%	0.7%	0.6%	2.0%
Avg. next 15 yrs	0.6%	0.4%	0.9%	1.6%	0.6%	0.7%	0.7%	2.4%
Avg. next 20 yrs	0.7%	0.6%	0.9%	1.7%	0.6%	0.8%	0.8%	2.4%
Avg. next 25 yrs	0.7%	0.6%	0.9%	1.6%	0.7%	0.8%	0.8%	2.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

WCMA
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	1,764		1,756		1,804		1,818		51.9
2007	1,778	0.8%	1,748	-0.4%	1,796	-0.4%	1,810	-0.4%	51.3
2008	1,717	-3.4%	1,746	-0.1%	1,797	0.0%	1,811	0.1%	44.7
2009	1,701	-0.9%	1,741	-0.3%	1,793	-0.2%	1,808	-0.2%	42.5
2010	1,740	2.3%	1,676	-3.7%	1,731	-3.5%	1,746	-3.4%	59.2
2011	1,637	-5.9%	1,671	-0.3%	1,726	-0.3%	1,741	-0.3%	45.9
2012	1,719	5.0%	1,692	1.2%	1,743	1.0%	1,758	1.0%	54.1
2013	1,776	3.3%	1,780	5.2%	1,834	5.2%	1,850	5.2%	49.8
2014	1,677	-5.6%	1,669	-6.2%	1,722	-6.1%	1,737	-6.1%	54.3
2015	1,589	-5.2%	1,627	-2.6%	1,678	-2.6%	1,692	-2.6%	46.2
2016	1,595	0.3%	1,596	-1.9%	1,655	-1.3%	1,672	-1.2%	52.8
2017	1,673	4.9%	1,594	-0.1%	1,665	0.6%	1,685	0.8%	59.0
2018	1,691	1.1%	1,633	2.5%	1,695	1.8%	1,712	1.6%	57.3
2019	1,515	-10.4%	1,545	-5.4%	1,604	-5.4%	1,621	-5.3%	46.6
2020	1,501	-1.0%	1,584	2.6%	1,648	2.7%	1,666	2.8%	43.9
2021	1,621	8.0%	1,604	1.2%	1,665	1.0%	1,682	1.0%	49.5
2022	-	-	1,604	0.0%	1,671	0.4%	1,690	0.5%	-
2023		-	1,572	-2.0%	1,639	-1.9%	1,658	-1.9%	
2024		-	1,589	1.1%	1,658	1.1%	1,677	1.1%	
2025	-	-	1,606	1.1%	1,676	1.1%	1,695	1.1%	-
2026	-	-	1,648	2.6%	1,715	2.4%	1,734	2.3%	-
2027	-	-	1,692	2.7%	1,760	2.6%	1,779	2.6%	-
2028	-	-	1,754	3.7%	1,823	3.6%	1,842	3.6%	-
2029	-	-	1,817	3.6%	1,887	3.5%	1,906	3.5%	-
2030	-	-	1,899	4.5%	1,970	4.4%	1,990	4.4%	-
2031	-	-	2,001	5.4%	2,073	5.2%	2,093	5.2%	-
2032	-	-	2,121	6.0%	2,193	5.8%	2,214	5.8%	-
2033	-	-	2,259	6.5%	2,332	6.3%	2,353	6.3%	-
2034	-	-	2,411	6.7%	2,485	6.6%	2,506	6.5%	-
2035	-	-	2,579	6.9%	2,654	6.8%	2,675	6.7%	-
2036	-	-	2,754	6.8%	2,830	6.6%	2,851	6.6%	-
2037	-		2,939	6.7%	3,016	6.6%	3,038	6.5%	-
2038	-		3,105	5.7%	3,183	5.5%	3,205	5.5%	-
2039	-		3,279	5.6%	3,358	5.5%	3,380	5.5%	-
2040	-		3,467	5.7%	3,546	5.6%	3,569	5.6%	-
2041	-		3,614	4.2%	3,694	4.2%	3,717	4.2%	-
2042	-		3,759	4.0%	3,840	4.0%	3,863	3.9%	-
2043	-		3,892	3.5%	3,974	3.5%	3,998	3.5%	-
2044	-		4,021	3.3%	4,105	3.3%	4,129	3.3%	-
2045	-		4,130	2.7%	4,216	2.7%	4,240	2.7%	-
2046	-		4,227	2.3%	4,313	2.3%	4,337	2.3%	-
2047	-		4,319	2.2%	4,406	2.1%	4,430	2.1%	-
2048	-		4,406	2.0%	4,494	2.0%	4,519	2.0%	-
2049	-		4,451	1.0%	4,540	1.0%	4,565	1.0%	-
2050	-		4,477	0.6%	4,567	0.6%	4,592	0.6%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.6%	-0.5%	-0.5%
Avg. last 10 yrs	-0.4%	-0.4%	-0.3%
Avg. last 5 yrs	0.1%	0.1%	0.1%
BASE 2020			
Avg. next 5 yrs	0.5%	0.6%	0.6%
Avg. next 10 yrs	2.2%	2.2%	2.2%
Avg. next 15 yrs	3.7%	3.6%	3.6%
Avg. next 20 yrs	4.1%	4.1%	4.0%
Avg. next 25 yrs	4.0%	3.9%	3.9%

HDD_wtd

NORMAL	50.4
EXTREME 90/10	58.2
EXTREME 95/5	60.4

***impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response**

WCMA	WINTER 50/50 Peaks (MW) (before & after DERs)															
	SYSTEM PEAK								DER IMPACTS							
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	1,838	1,756	1,838	1,838	1,838	1,838	1,838	**1,756**	(82)	0	0.0	0.0	0.0	0.0	(82)
2007	1,856	1,748	1,856	1,856	1,856	1,856	1,856	**1,748**	(108)	0	0.0	0.0	0.0	0.0	(108)
2008	1,870	1,746	1,870	1,870	1,870	1,870	1,870	**1,746**	(124)	0	0.0	0.0	0.0	0.0	(124)
2009	1,894	1,741	1,894	1,894	1,894	1,894	1,894	**1,741**	(152)	0	0.0	0.0	0.0	0.0	(152)
2010	1,854	1,676	1,854	1,854	1,854	1,854	1,854	**1,676**	(178)	0	0.0	0.0	0.0	0.0	(178)
2011	1,877	1,671	1,877	1,877	1,877	1,877	1,877	**1,671**	(206)	0	0.0	0.0	0.0	0.0	(206)
2012	1,928	1,692	1,928	1,928	1,928	1,928	1,928	**1,692**	(236)	0	0.1	0.0	0.0	0.0	(236)
2013	2,057	1,780	2,057	2,057	2,057	2,057	2,057	**1,780**	(277)	0	0.2	0.0	0.0	0.0	(277)
2014	1,991	1,669	1,991	1,991	1,991	1,991	1,991	**1,669**	(322)	0	0.4	0.0	0.0	0.0	(322)
2015	1,998	1,626	1,998	1,999	1,998	1,998	1,998	**1,627**	(372)	0	0.6	0.0	0.0	0.0	(371)
2016	2,018	1,595	2,018	2,019	2,018	2,018	2,018	**1,596**	(423)	0	0.8	0.0	0.0	0.0	(422)
2017	2,067	1,592	2,067	2,069	2,067	2,067	2,067	**1,594**	(475)	0	1.2	0.0	(0.2)	0.0	(474)
2018	2,164	1,632	2,164	2,166	2,164	2,163	2,164	**1,633**	(532)	0	2.0	0.0	(0.8)	0.0	(531)
2019	2,139	1,550	2,139	2,142	2,139	2,131	2,139	**1,545**	(589)	0	2.6	0.0	(7.9)	0.3	(594)
2020	2,243	1,598	2,243	2,246	2,243	2,224	2,244	**1,584**	(645)	0	3.4	0.0	(18.3)	1.0	(658)
2021	2,317	1,635	2,317	2,321	2,317	2,278	2,318	**1,604**	(681)	0	4.7	0.0	(38.2)	1.8	(713)
2022	2,351	1,650	2,351	2,358	2,351	2,293	2,355	**1,604**	(700)	0	7.4	0.0	(58.2)	4.2	(747)
2023	2,346	1,629	2,346	2,359	2,346	2,268	2,355	**1,572**	(717)	0	12.4	0.0	(78.2)	9.0	(774)
2024	2,386	1,653	2,386	2,405	2,386	2,288	2,401	**1,589**	(733)	0	19.2	0.0	(98.1)	15.3	(797)
2025	2,417	1,670	2,417	2,445	2,417	2,303	2,439	**1,606**	(747)	0	28.1	0.0	(114.0)	21.7	(811)
2026	2,324	1,566	2,324	2,377	2,324	2,327	2,350	**1,648**	(758)	0	53.4	0.0	3.5	25.9	(676)
2027	2,348	1,580	2,348	2,423	2,348	2,352	2,382	**1,692**	(768)	0	74.8	0.0	3.8	33.8	(656)
2028	2,381	1,605	2,381	2,484	2,381	2,385	2,424	**1,754**	(776)	0	102.9	0.0	4.0	42.7	(627)
2029	2,402	1,619	2,402	2,544	2,402	2,406	2,454	**1,817**	(784)	0	142.0	0.0	4.2	52.3	(585)
2030	2,431	1,641	2,431	2,622	2,431	2,435	2,493	**1,899**	(790)	0	190.9	0.0	4.4	62.5	(532)
2031	2,459	1,664	2,459	2,713	2,459	2,463	2,538	**2,001**	(795)	0	253.6	0.0	4.5	78.8	(458)
2032	2,487	1,688	2,487	2,809	2,487	2,491	2,594	**2,121**	(799)	0	322.1	0.0	4.6	106.7	(366)
2033	2,515	1,712	2,515	2,912	2,515	2,519	2,660	**2,259**	(803)	0	396.9	0.0	4.6	145.5	(256)
2034	2,542	1,736	2,542	3,018	2,542	2,546	2,736	**2,411**	(806)	0	476.7	0.0	4.7	194.2	(130)
2035	2,571	1,763	2,571	3,131	2,571	2,576	2,823	**2,579**	(808)	0	559.8	0.0	4.7	251.5	8
2036	2,601	1,789	2,601	3,244	2,601	2,605	2,917	**2,754**	(811)	0	643.4	0.0	4.8	316.1	153
2037	2,637	1,823	2,637	3,362	2,637	2,641	3,023	**2,939**	(814)	0	725.0	0.0	4.8	386.4	302
2038	2,653	1,836	2,653	3,456	2,653	2,657	3,113	**3,105**	(816)	0	803.8	0.0	4.8	460.5	453
2039	2,672	1,853	2,672	3,557	2,672	2,677	3,209	**3,279**	(819)	0	884.8	0.0	4.9	536.7	607
2040	2,698	1,876	2,698	3,671	2,698	2,703	3,311	**3,467**	(822)	0	973.1	0.0	4.9	613.2	769
2041	2,720	1,895	2,720	3,746	2,720	2,724	3,408	**3,614**	(824)	0	1,026.2	0.0	4.9	688.2	895
2042	2,747	1,920	2,747	3,821	2,747	2,752	3,507	**3,759**	(827)	0	1,074.2	0.0	4.9	760.1	1,012
2043	2,773	1,943	2,773	3,890	2,773	2,778	3,600	**3,892**	(830)	0	1,117.0	0.0	4.9	827.2	1,119
2044	2,887	2,054	2,887	4,015	2,887	2,709	3,902	**4,021**	(832)	0	1,128.6	0.0	(177.3)	1,015.2	1,134
2045	2,906	2,071	2,906	4,067	2,906	2,728	3,982	**4,130**	(835)	0	1,160.7	0.0	(177.7)	1,076.5	1,224
2046	2,926	2,088	2,926	4,114	2,926	2,748	4,054	**4,227**	(838)	0	1,188.3	0.0	(177.7)	1,128.2	1,301
2047	2,955	2,115	2,955	4,167	2,955	2,778	4,125	**4,319**	(840)	0	1,211.8	0.0	(177.7)	1,169.4	1,363
2048	2,995	2,152	2,995	4,227	2,995	2,818	4,195	**4,406**	(843)	0	1,231.9	0.0	(177.7)	1,199.3	1,410
2049	3,008	2,163	3,008	4,257	3,008	2,831	4,226	**4,451**	(846)	0	1,249.0	0.0	(177.7)	1,217.4	1,443
2050	3,016	2,168	3,016	4,280	3,016	2,839	4,240	**4,477**	(848)	0	1,263.6	0.0	(177.7)	1,223.5	1,461

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Avg. last 15 yrs	1.6%	-0.5%	1.6%	1.6%	1.6%	1.4%	1.6%	-0.6%
Avg. last 10 yrs	2.1%	-0.2%	2.1%	2.1%	2.1%	2.0%	2.1%	-0.4%
Avg. last 5 yrs	2.8%	0.5%	2.8%	2.8%	2.8%	2.5%	2.8%	0.1%
BASE 2020								
Avg. next 5 yrs	0.1%	-0.9%	0.1%	0.5%	0.1%	0.4%	0.3%	0.5%
Avg. next 10 yrs	0.6%	0.2%	0.6%	1.6%	0.6%	0.8%	0.9%	2.2%
Avg. next 15 yrs	0.8%	0.6%	0.8%	2.3%	0.8%	0.9%	1.5%	3.7%
Avg. next 20 yrs	0.8%	0.7%	0.8%	2.4%	0.8%	0.9%	1.9%	4.1%
Avg. next 25 yrs	0.9%	1.0%	0.9%	2.3%	0.9%	0.8%	2.3%	4.0%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Nantucket (COMPANY)

NANT
Annual Peaks **AFTER DER Impacts ***

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	Peak Season (50-50)
2006	39		37		39		39		S
2007	39	-1.2%	41	10.5%	43	11.9%	44	12.2%	S
2008	39	-0.5%	40	-1.5%	42	-2.2%	43	-2.4%	S
2009	39	1.3%	40	1.2%	43	1.5%	44	1.6%	S
2010	40	2.7%	39	-3.2%	42	-1.9%	43	-1.6%	S
2011	41	0.8%	41	5.4%	44	5.1%	45	5.0%	S
2012	44	8.2%	45	8.2%	47	6.5%	48	6.1%	S
2013	45	3.7%	45	0.2%	47	0.7%	48	0.8%	S
2014	41	-10.9%	45	0.1%	48	1.0%	49	1.3%	S
2015	46	12.5%	44	-2.5%	47	-1.3%	48	-1.0%	S
2016	50	10.3%	49	12.1%	53	11.8%	54	11.7%	S
2017	46	-8.7%	46	-6.9%	49	-7.9%	50	-8.2%	S
2018	50	8.9%	49	7.2%	53	9.1%	54	9.6%	S
2019	51	1.2%	47	-3.5%	51	-4.6%	52	-4.8%	S
2020	52	2.5%	48	2.4%	54	7.3%	56	8.5%	S
2021	53	2.4%	51	6.3%	56	2.0%	57	1.0%	S
2022	58	9.4%	52	1.0%	58	3.9%	59	4.7%	S
2023	-	-	53	2.1%	59	2.2%	61	2.2%	S
2024	-	-	54	1.7%	60	1.8%	62	1.9%	S
2025	-	-	55	1.7%	61	1.7%	63	1.8%	S
2026	-	-	56	1.9%	62	2.0%	64	2.0%	S
2027	-	-	57	2.2%	64	2.3%	66	2.3%	S
2028	-	-	58	2.3%	65	2.3%	67	2.3%	S
2029	-	-	60	2.4%	67	2.2%	69	2.2%	S
2030	-	-	61	2.3%	68	2.2%	70	2.2%	S
2031	-	-	63	2.5%	70	2.4%	72	2.4%	S
2032	-	-	64	2.5%	72	2.4%	74	2.4%	S
2033	-	-	66	2.5%	73	2.4%	75	2.4%	S
2034	-	-	67	2.6%	75	2.5%	77	2.5%	S
2035	-	-	69	2.5%	77	2.4%	79	2.4%	S
2036	-	-	71	2.4%	79	2.4%	81	2.4%	S
2037	-	-	72	2.3%	81	2.3%	83	2.3%	S
2038	-		74	2.2%	82	2.2%	85	2.1%	S
2039	-		76	2.2%	84	2.1%	86	2.1%	S
2040	-		77	2.1%	86	2.1%	88	2.1%	S
2041	-		79	1.7%	87	1.7%	90	1.6%	S
2042	-		80	1.5%	88	1.5%	91	1.5%	S
2043	-		81	1.4%	90	1.4%	92	1.4%	S
2044	-		82	1.2%	91	1.2%	93	1.2%	S
2045	-		83	1.1%	92	1.1%	94	1.1%	S
2046	-		84	1.0%	93	1.0%	95	1.0%	S
2047	-		84	0.9%	94	0.9%	96	0.9%	S
2048	-		85	0.8%	94	0.8%	97	0.8%	S
2049	-		86	0.7%	95	0.7%	98	0.7%	S
2050	-		86	0.6%	96	0.6%	98	0.6%	S

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	1.7%	1.9%	2.0%
Avg. last 10 yrs	1.5%	2.0%	2.2%
Avg. last 5 yrs	2.6%	3.4%	3.7%
Base 2022			
Avg. next 5 yrs	1.9%	2.0%	2.0%
Avg. next 10 yrs	2.1%	2.2%	2.2%
Avg. next 15 yrs	2.3%	2.2%	2.2%
Avg. next 20 yrs	2.2%	2.2%	2.2%
Avg. next 25 yrs	2.0%	2.0%	1.9%

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps, and company demand response*

NANT	Annual 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	37	37	37	37	37	37	37	**37**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2007	41	41	41	41	41	41	41	**41**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2008	41	40	41	41	41	41	41	**40**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2009	41	40	41	41	41	41	41	**40**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2010	40	39	40	40	40	40	40	**39**	(1)	(0)	0.0	0.0	0.0	0.0	(1)
2011	43	41	43	43	43	43	43	**41**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2012	46	45	46	46	46	46	46	**45**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2013	47	45	47	47	47	47	47	**45**	(2)	(0)	0.0	0.0	0.0	0.0	(2)
2014	47	45	47	47	47	47	47	**45**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2015	47	44	47	47	47	47	47	**44**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2016	53	49	52	53	53	53	53	**49**	(4)	(0)	0.0	(0.0)	0.0	0.0	(4)
2017	50	46	50	50	50	50	50	**46**	(4)	(0)	0.0	(0.0)	0.0	0.0	(4)
2018	54	49	53	54	54	54	54	**49**	(5)	(1)	0	(0)	0	0	(5)
2019	53	48	52	53	53	53	53	**47**	(5)	(1)	0	(0)	0	0	(6)
2020	54	48	54	54	54	54	54	**48**	(6)	(0)	0	(0)	0	0	(6)
2021	58	52	57	58	58	58	58	**51**	(6)	(1)	0	(0)	0	0	(7)
2022	64	58	58	64	64	64	64	**52**	(6)	(6)	0	0	0	0	(12)
2023	61	54	60	61	60	61	61	**53**	(7)	(1)	0	(0)	0	0	(8)
2024	62	55	61	62	62	62	62	**54**	(7)	(1)	0	(0)	0	0	(8)
2025	63	56	62	63	63	63	63	**55**	(7)	(1)	0	(0)	0	0	(8)
2026	64	57	63	64	64	64	64	**56**	(7)	(1)	0	(0)	0	0	(8)
2027	65	58	64	66	65	65	65	**57**	(7)	(1)	0	(0)	0	0	(8)
2028	65	58	65	66	65	65	65	**58**	(7)	(0)	1	(0)	0	0	(7)
2029	66	59	66	67	66	66	66	**60**	(7)	(0)	1	(0)	0	0	(7)
2030	67	60	67	69	67	67	68	**61**	(8)	(0)	1	(0)	0	0	(6)
2031	68	61	68	70	68	68	69	**63**	(8)	(0)	2	(0)	0	0	(6)
2032	69	62	69	72	69	69	70	**64**	(8)	(0)	2	(0)	0	0	(5)
2033	70	63	70	74	70	70	71	**66**	(8)	(0)	3	(0)	0	0	(5)
2034	71	64	71	75	71	71	72	**67**	(8)	(0)	4	(0)	0	0	(4)
2035	72	65	72	77	72	72	73	**69**	(8)	(0)	4	(0)	0	0	(3)
2036	73	66	73	79	73	73	74	**71**	(8)	(0)	5	(0)	0	1	(3)
2037	74	66	74	80	74	74	75	**72**	(8)	(0)	6	(0)	0	1	(2)
2038	75	67	75	82	75	75	76	**74**	(8)	(0)	7	(0)	0	1	(1)
2039	76	68	76	83	76	76	77	**76**	(8)	(0)	7	(0)	0	1	(1)
2040	77	69	77	85	77	77	78	**77**	(8)	(0)	8	(0)	0	1	0
2041	78	70	77	86	77	78	79	**79**	(8)	(0)	8	(0)	0	1	1
2042	79	71	78	87	78	79	80	**80**	(8)	(0)	9	(0)	0	1	1
2043	79	71	79	89	79	79	80	**81**	(8)	(0)	9	(0)	0	1	2
2044	80	72	79	90	80	80	81	**82**	(8)	(0)	10	(0)	0	1	2
2045	81	72	80	90	80	81	82	**83**	(8)	(0)	10	(0)	0	1	2
2046	81	73	81	91	81	81	82	**84**	(8)	(0)	10	(0)	0	1	2
2047	82	74	81	92	81	82	83	**84**	(8)	(0)	10	(0)	0	1	3
2048	82	74	82	93	82	82	83	**85**	(8)	(0)	11	(0)	0	1	3
2049	83	74	82	93	82	83	84	**86**	(8)	(0)	11	(0)	0	1	3
2050	83	75	83	94	83	83	84	**86**	(8)	(0)	11	(0)	0	1	3

Avg. last 15 yrs	3.0%	2.4%	2.3%	3.0%	3.0%	3.0%	3.0%	1.7%
Avg. last 10 yrs	3.3%	2.6%	2.3%	3.3%	3.3%	3.3%	3.3%	1.5%
Avg. last 5 yrs	5.3%	4.8%	3.2%	5.3%	5.3%	5.3%	5.3%	2.6%
Base 2022								
Avg. next 5 yrs	0.3%	0.1%	1.9%	0.5%	0.3%	0.3%	0.4%	1.9%
Avg. next 10 yrs	0.8%	0.7%	1.7%	1.1%	0.8%	0.8%	0.8%	2.1%
Avg. next 15 yrs	1.0%	0.9%	1.6%	1.5%	1.0%	1.0%	1.0%	2.3%
Avg. next 20 yrs	1.0%	1.0%	1.5%	1.6%	1.0%	1.0%	1.1%	2.2%
Avg. next 25 yrs	1.0%	1.0%	1.3%	1.4%	0.9%	1.0%	1.0%	2.0%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (Adds load)

NANT
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2006	28		30		32		33		41.0
2007	28	0.9%	33	9.8%	35	7.6%	35	7.1%	27.3
2008	25	-9.4%	25	-23.2%	27	-22.3%	27	-22.1%	43.9
2009	26	1.4%	27	8.4%	29	8.0%	29	7.9%	35.0
2010	25	-3.2%	26	-4.9%	28	-5.0%	28	-5.1%	37.4
2011	24	-4.6%	25	-3.8%	27	-3.6%	27	-3.6%	39.1
2012	27	14.5%	26	6.0%	28	7.3%	29	7.6%	50.0
2013	29	7.9%	30	13.1%	32	12.2%	33	12.0%	36.2
2014	30	1.1%	28	-4.6%	30	-4.6%	31	-4.6%	48.8
2015	30	1.6%	28	-1.2%	30	0.1%	31	0.5%	52.9
2016	29	-4.4%	29	3.2%	32	3.8%	32	4.0%	42.1
2017	32	12.0%	31	7.0%	34	8.2%	35	8.6%	47.9
2018	33	3.6%	33	5.6%	36	3.9%	36	3.5%	44.0
2019	29	-12.6%	31	-4.7%	34	-4.0%	35	-3.8%	36.7
2020	33	11.6%	33	5.9%	36	4.1%	36	3.7%	41.2
2021	32	-2.1%	33	0.9%	36	2.3%	37	2.7%	38.6
2022	-	-	34	1.8%	37	1.9%	38	1.9%	-
2023		-	35	2.4%	38	2.4%	39	2.4%	
2024		-	35	2.2%	39	2.2%	40	2.1%	
2025	-	-	36	2.1%	40	2.1%	41	2.1%	-
2026	-	-	37	2.5%	41	2.5%	42	2.5%	-
2027	-	-	38	2.9%	42	2.8%	43	2.8%	-
2028	-	-	39	3.1%	43	3.0%	44	3.0%	-
2029	-	-	41	3.2%	44	3.1%	45	3.1%	-
2030	-	-	42	3.2%	46	3.1%	47	3.1%	-
2031	-	-	44	3.7%	47	3.6%	48	3.5%	-
2032	-	-	45	4.0%	49	3.9%	50	3.8%	-
2033	-	-	47	4.3%	51	4.1%	52	4.1%	-
2034	-	-	49	4.6%	53	4.4%	55	4.3%	-
2035	-	-	52	4.6%	56	4.4%	57	4.3%	-
2036	-	-	54	4.6%	58	4.4%	59	4.3%	-
2037	-		57	4.5%	61	4.3%	62	4.2%	-
2038	-		59	4.4%	63	4.2%	64	4.1%	-
2039	-		62	4.3%	66	4.1%	67	4.0%	-
2040	-		64	4.2%	69	4.0%	70	4.0%	-
2041	-		66	3.3%	71	3.2%	72	3.2%	-
2042	-		68	3.0%	73	2.9%	74	2.9%	-
2043	-		70	2.7%	75	2.6%	76	2.6%	-
2044	-		72	2.4%	76	2.3%	78	2.3%	-
2045	-		73	2.1%	78	2.0%	79	2.0%	-
2046	-		75	1.8%	79	1.7%	80	1.7%	-
2047	-		76	1.5%	80	1.4%	82	1.4%	-
2048	-		77	1.2%	81	1.2%	83	1.2%	-
2049	-		77	0.9%	82	0.9%	83	0.9%	-
2050	-		78	0.7%	83	0.7%	84	0.7%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	0.8%	0.8%	0.9%
Avg. last 10 yrs	3.0%	3.2%	3.3%
Avg. last 5 yrs	2.8%	2.8%	2.8%
Base 2021			
Avg. next 5 yrs	2.2%	2.2%	2.2%
Avg. next 10 yrs	2.7%	2.7%	2.6%
Avg. next 14 yrs	3.5%	3.4%	3.4%

HDD_wtd

NORMAL	42.6
EXTREME 90/10	51.5
EXTREME 95/5	54.1

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response*
(solar and demand response are zero at times of winter peak)

NANT	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2006	31	30	31	31	31	31	31	**30**	(1)	0	0.0	0.0	0.0	0.0	(1)
2007	34	33	34	34	34	34	34	**33**	(1)	0	0.0	0.0	0.0	0.0	(1)
2008	26	25	26	26	26	26	26	**25**	(1)	0	0.0	0.0	0.0	0.0	(1)
2009	29	27	29	29	29	29	29	**27**	(2)	0	0.0	0.0	0.0	0.0	(2)
2010	28	26	28	28	28	28	28	**26**	(2)	0	0.0	0.0	0.0	0.0	(2)
2011	27	25	27	27	27	27	27	**25**	(2)	0	0.0	0.0	0.0	0.0	(2)
2012	29	26	29	29	29	29	29	**26**	(3)	0	0.0	0.0	0.0	0.0	(3)
2013	33	30	33	33	33	33	33	**30**	(3)	0	0.0	0.0	0.0	0.0	(3)
2014	32	28	32	32	32	32	32	**28**	(4)	0	0.0	0.0	0.0	0.0	(4)
2015	32	29	31	32	32	32	32	**28**	(3)	(1)	0.0	0.0	0.0	0.0	(4)
2016	32	29	32	32	32	32	32	**29**	(3)	(0)	0.0	0.0	0.0	0.0	(3)
2017	36	31	36	36	36	36	36	**31**	(5)	0	0.0	0.0	0.0	0.0	(5)
2018	39	33	39	39	39	39	39	**33**	(6)	0	0.0	0.0	0.0	0.0	(6)
2019	38	31	38	38	38	38	38	**31**	(6)	0	0.0	0.0	0.0	0.0	(6)
2020	40	33	40	40	40	40	40	**33**	(7)	0	0.0	0.0	0.0	0.0	(7)
2021	45	37	41	45	45	45	45	**33**	(8)	(4)	0.0	0.0	0.0	0.0	(12)
2022	41	34	41	42	41	41	42	**34**	(8)	0	0.1	0.0	0.0	0.0	(8)
2023	42	34	42	43	42	42	42	**35**	(8)	0	0.2	0.0	0.0	0.1	(8)
2024	43	35	43	43	43	43	43	**35**	(8)	0	0.3	0.0	0.0	0.2	(8)
2025	44	36	44	44	44	44	44	**36**	(8)	0	0.4	0.0	0.0	0.3	(8)
2026	45	36	45	45	45	45	45	**37**	(8)	0	0.6	0.0	0.0	0.3	(7)
2027	45	37	45	46	45	45	46	**38**	(8)	0	0.8	0.0	0.0	0.4	(7)
2028	46	38	46	47	46	46	47	**39**	(9)	0	1.1	0.0	0.0	0.6	(7)
2029	47	38	47	49	47	47	48	**41**	(9)	0	1.6	0.0	0.0	0.7	(6)
2030	48	39	48	50	48	48	49	**42**	(9)	0	2.1	0.0	0.0	0.8	(6)
2031	48	40	48	51	48	48	50	**44**	(9)	0	2.8	0.0	0.0	1.0	(5)
2032	49	40	49	53	49	49	51	**45**	(9)	0	3.6	0.0	0.0	1.4	(4)
2033	50	41	50	54	50	50	52	**47**	(9)	0	4.4	0.0	0.0	1.9	(3)
2034	50	42	50	56	50	50	53	**49**	(9)	0	5.3	0.0	0.0	2.6	(1)
2035	51	42	51	57	51	51	54	**52**	(9)	0	6.2	0.0	0.0	3.3	1
2036	52	43	52	59	52	52	56	**54**	(9)	0	7.2	0.0	0.0	4.2	2
2037	52	43	52	60	52	52	57	**57**	(9)	0	8.7	0.0	0.0	5.1	5
2038	52	43	52	62	52	52	58	**59**	(9)	0	9.7	0.0	0.0	6.1	7
2039	53	44	53	64	53	53	60	**62**	(9)	0	10.7	0.0	0.0	7.1	9
2040	53	44	53	65	53	53	62	**64**	(9)	0	11.7	0.0	0.0	8.1	11
2041	54	45	54	66	54	54	63	**66**	(9)	0	12.4	0.0	0.0	9.1	12
2042	55	45	55	67	55	55	65	**68**	(9)	0	12.9	0.0	0.0	10.1	14
2043	55	46	55	68	55	55	66	**70**	(9)	0	13.5	0.0	0.0	11.0	15
2044	55	46	55	69	55	55	67	**72**	(9)	0	13.9	0.0	0.0	11.8	17
2045	56	47	56	70	56	56	68	**73**	(9)	0	14.3	0.0	0.0	12.5	18
2046	56	47	56	71	56	56	69	**75**	(9)	0	14.6	0.0	0.0	13.1	18
2047	57	47	57	72	57	57	70	**76**	(9)	0	14.9	0.0	0.0	13.6	19
2048	57	48	57	72	57	57	71	**77**	(9)	0	15.2	0.0	0.0	13.9	20
2049	57	48	57	73	57	57	71	**77**	(9)	0	15.4	0.0	0.0	14.1	20
2050	58	48	58	73	58	58	72	**78**	(9)	0	15.6	0.0	0.0	14.2	20

	-							
Avg. last 15 yrs	2.6%	1.5%	1.9%	2.6%	2.6%	2.6%	2.6%	0.8%
Avg. last 10 yrs	5.2%	4.2%	4.2%	5.2%	5.2%	5.2%	5.2%	3.0%
Avg. last 5 yrs	6.8%	5.1%	4.8%	6.8%	6.8%	6.8%	6.8%	2.8%
Base 2021								
Avg. next 5 yrs	-0.1%	-0.6%	1.8%	0.1%	-0.1%	-0.1%	0.0%	2.2%
Avg. next 10 yrs	0.8%	0.6%	1.7%	1.3%	0.8%	0.8%	1.0%	2.7%
Avg. next 15 yrs	1.0%	0.9%	1.6%	1.8%	1.0%	1.0%	1.5%	3.3%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Appendix B: Power Supply Areas

The Company provides peak load growth forecast for the 18 power supply areas in its Massachusetts service territory. The forecasting process leverages regional information to allocates the system-level load growth projection and outlook on distributed energy resources (DER) to the feeder level. The allocations of load growth, energy efficiency, and medium- and heavy-duty electric vehicle growth use regional energy growth information. The allocations on solar PV, light-duty electric vehicles, and electric heat pumps use demographic information, heating fuel type information, and land availability. The feeder level forecasts are then aggregated to the power supply area level, and a year-over-year peak load growth rate is generated and presented in the tables below.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) — **after EE, PV, EV, and EH impacts**

			2022 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	_2023	_2024	_2025	_2026	_2027	'23 to '27	'28 to '32	'33 to '37	'38 to '42	'43 to '47
MA	Adams	WCMA	97.7%	103.2%	104.8%	2.0	1.8	2.0	1.4	2.4	1.9	3.6	3.9	3.6	2.1
MA	Athol	WCMA	97.7%	103.2%	104.8%	1.7	3.3	0.8	3.2	4.0	2.6	3.9	4.3	2.5	1.1
MA	Attleboro	SEMA	93.6%	102.3%	104.7%	0.1	0.2	0.8	0.3	0.1	0.3	2.5	3.1	2.4	1.1
MA	Brockton	SEMA	93.6%	102.3%	104.7%	0.0	0.3	1.0	0.6	1.5	0.7	2.4	3.5	2.3	1.1
MA	Essex	NEMA	94.7%	102.4%	104.6%	0.6	1.3	1.5	1.2	2.0	1.3	2.6	3.7	2.9	1.3
MA	Fall River	SEMA	93.6%	102.3%	104.7%	0.4	0.5	0.7	0.3	1.5	0.7	2.0	2.9	2.1	1.2
MA	Gardner	WCMA	97.7%	103.2%	104.8%	1.7	2.1	1.8	-0.3	3.0	1.7	2.9	3.5	2.0	0.8
MA	Leominster	WCMA	97.7%	103.2%	104.8%	1.2	1.9	1.8	0.9	1.9	1.5	2.2	2.6	2.8	1.7
MA	Marlboro	WCMA	97.7%	103.2%	104.8%	1.3	1.5	1.5	1.2	1.9	1.5	1.6	2.6	2.5	1.3
MA	Merrimack	NEMA/WCMA	96.0%	102.7%	104.6%	1.0	0.8	1.2	0.8	1.6	1.1	2.0	2.9	2.5	1.4
MA	North Hampton	WCMA	97.7%	103.2%	104.8%	1.9	1.9	1.9	0.7	2.4	1.8	2.5	3.4	3.4	1.5
MA	Palmer	WCMA	97.7%	103.2%	104.8%	1.9	0.0	1.3	1.9	3.1	1.6	3.7	3.9	2.2	1.1
MA	South Berkshire	WCMA	97.7%	103.2%	104.8%	1.8	1.9	2.1	0.7	2.4	1.8	2.7	4.1	3.3	1.2
MA	Surburban	NEMA	94.7%	102.4%	104.6%	1.0	1.2	1.4	1.1	1.8	1.3	2.2	2.8	3.2	2.0
MA	Uxbridge	SEMA/WCMA	93.6%	102.3%	104.7%	0.3	1.5	1.5	1.7	2.5	1.5	3.4	3.6	2.7	1.0
MA	Webster	WCMA	97.7%	103.2%	104.8%	0.6	2.6	0.3	1.1	2.1	1.3	3.3	3.8	2.3	1.2
MA	Weymouth	SEMA	93.6%	102.3%	104.7%	0.4	0.4	0.9	0.5	1.3	0.7	1.8	3.3	3.8	1.9
MA	Worcester	WCMA	97.7%	103.2%	104.8%	1.4	2.1	1.7	1.5	2.3	1.8	2.4	2.6	2.4	1.6

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current summer peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) **after EE, EV, and EH impacts**

			2022 Weather-Adjustments (2)				Annual Growth Rates (percents) (3)				5-yr avg	5-yr avg	5-yr avg	5-yr avg	5-yr avg
State	**PSA**	**Zone (1)**	**for 50/50**	**for 90/10**	**for 95/5**	**_2023**	**_2024**	**_2025**	**_2026**	**_2027**	**'23 to '27**	**'28 to '32**	**'33 to '37**	**'38 to '42**	**'43 to '47**
MA	Adams	WCMA	97.7%	103.2%	104.8%	2.2	2.0	2.1	1.7	2.5	2.1	3.8	3.8	3.6	2.1
MA	Athol	WCMA	97.7%	103.2%	104.8%	3.9	3.1	3.2	3.2	3.7	3.4	4.2	4.0	2.4	1.1
MA	Attleboro	SEMA	93.6%	102.3%	104.7%	0.8	0.7	1.0	0.7	1.6	0.9	2.3	2.8	2.4	1.2
MA	Brockton	SEMA	93.6%	102.3%	104.7%	0.6	0.8	1.1	0.9	1.8	1.0	2.4	3.2	2.4	1.1
MA	Essex	NEMA	94.7%	102.4%	104.6%	1.2	1.4	1.6	1.3	2.2	1.6	2.7	3.4	2.9	1.3
MA	Fall River	SEMA	93.6%	102.3%	104.7%	0.6	0.6	0.9	0.6	1.6	0.9	2.2	2.5	2.2	1.2
MA	Gardner	WCMA	97.7%	103.2%	104.8%	1.9	1.7	1.9	2.0	2.3	2.0	3.0	3.3	2.3	1.1
MA	Leominster	WCMA	97.7%	103.2%	104.8%	2.0	1.9	2.0	1.5	2.3	1.9	2.5	2.5	2.7	1.7
MA	Marlboro	WCMA	97.7%	103.2%	104.8%	1.3	1.5	1.7	1.3	2.1	1.6	2.0	2.4	2.2	1.4
MA	Merrimack	NEMA/WCMA	96.0%	102.7%	104.6%	1.1	1.3	1.5	1.1	1.9	1.4	2.2	2.6	2.5	1.4
MA	North Hampton	WCMA	97.7%	103.2%	104.8%	2.0	2.0	2.1	1.7	2.5	2.0	2.7	3.0	3.5	1.6
MA	Palmer	WCMA	97.7%	103.2%	104.8%	2.2	2.0	2.2	2.1	2.8	2.3	3.4	3.7	2.3	1.1
MA	South Berkshire	WCMA	97.7%	103.2%	104.8%	1.9	2.0	2.1	1.9	2.5	2.1	3.3	3.9	3.3	1.2
MA	Surburban	NEMA	94.7%	102.4%	104.6%	1.2	1.4	1.6	1.2	2.0	1.5	2.3	2.7	3.2	2.0
MA	Uxbridge	SEMA/WCMA	93.6%	102.3%	104.7%	1.8	2.2	2.3	2.1	2.9	2.2	3.1	3.5	2.8	1.1
MA	Webster	WCMA	97.7%	103.2%	104.8%	1.9	1.8	1.9	1.9	2.4	2.0	3.1	3.6	2.6	1.3
MA	Weymouth	SEMA	93.6%	102.3%	104.7%	0.5	0.7	1.0	0.7	1.5	0.9	2.0	2.9	3.9	1.9
MA	Worcester	WCMA	97.7%	103.2%	104.8%	1.8	2.0	2.1	1.7	2.3	2.0	2.4	2.6	2.2	1.7

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current summer peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER)								after EE, PV, EV, and EH impacts							
			2021/22 Weather-Adjustments (2)					Annual Growth Rates (percent			5-yr avg	5-yr avg	5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 10/90	for 05/95	2022	2023	2024	2025	2026	'22 to '26	'27 to '31	'32 to '36	'37 to '41	'42 to '46
MA	Adams	WCMA	98.9%	102.7%	103.8%	2.2	2.3	2.5	2.3	3.1	2.5	6.0	7.0	6.0	4.0
MA	Athol	WCMA	98.9%	102.7%	103.8%	4.0	3.5	3.5	3.7	4.4	3.8	6.9	7.5	3.4	1.5
MA	Attleboro	SEMA	99.2%	103.2%	104.3%	1.1	1.2	1.9	1.5	2.7	1.7	4.4	6.4	5.3	2.2
MA	Brockton	SEMA	99.2%	103.2%	104.3%	0.6	1.1	1.9	1.9	2.7	1.6	4.9	7.3	5.4	2.7
MA	Essex	NEMA	99.7%	105.1%	106.6%	1.6	2.0	2.4	2.3	3.5	2.4	4.7	6.9	5.9	2.1
MA	Fall River	SEMA	99.2%	103.2%	104.3%	0.5	0.6	1.2	1.1	2.2	1.1	4.2	6.6	5.3	3.1
MA	Gardner	WCMA	98.9%	102.7%	103.8%	2.3	2.0	2.3	2.5	2.8	2.4	4.6	5.8	4.4	1.6
MA	Leominster	WCMA	98.9%	102.7%	103.8%	2.6	2.9	2.9	2.6	3.7	3.0	5.8	7.8	7.0	2.8
MA	Marlboro	WCMA	98.9%	102.7%	103.8%	1.6	1.9	2.2	2.6	3.8	2.4	2.9	5.0	4.4	1.9
MA	Merrimack	NEMA/WCMA	99.3%	104.0%	105.3%	0.8	1.5	1.9	1.9	2.7	1.7	4.0	6.2	5.4	3.2
MA	Northampton	WCMA	98.9%	102.7%	103.8%	2.1	2.3	2.6	2.3	3.2	2.5	4.4	6.6	6.7	3.2
MA	Palmer	WCMA	98.9%	102.7%	103.8%	2.4	2.3	2.7	2.8	3.6	2.7	5.4	6.7	4.2	1.8
MA	South Berkshire	WCMA	98.9%	102.7%	103.8%	2.0	2.2	2.6	2.7	3.2	2.6	5.5	7.2	5.6	2.0
MA	Surburban	NEMA	99.7%	105.1%	106.6%	1.3	1.7	2.1	2.0	2.8	2.0	4.0	6.6	6.8	4.2
MA	Uxbridge	SEMA/WCMA	99.2%	103.2%	104.3%	2.5	3.3	3.7	4.0	5.8	3.9	5.2	7.3	5.1	1.8
MA	Webster	WCMA	98.9%	102.7%	103.8%	2.3	2.2	2.7	2.8	3.5	2.7	4.7	6.3	4.6	1.8
MA	Weymouth	SEMA	99.2%	103.2%	104.3%	0.4	0.9	1.6	1.5	2.1	1.3	4.1	7.4	8.1	3.7
MA	Worcester	WCMA	98.9%	102.7%	103.8%	1.8	2.0	2.4	2.1	2.7	2.2	3.7	5.6	5.2	3.1

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents are under the 90/10 weather scenario and can be applied to the current summer peaks to determine what the growth for each area is.

Appendix C: Study Areas

The Company provides peak load growth forecast for the 46 study areas in its Massachusetts service territory. The forecasting process leverages regional information to allocates the system-level load growth projection and outlook on distributed energy resources (DER) to the feeder level. The allocations of load growth, energy efficiency, and medium- and heavy-duty electric vehicle growth use regional energy growth information. The allocations on solar PV, light-duty electric vehicles, and electric heat pumps use demographic information, heating fuel type information, and land availability. The feeder level forecasts are then aggregated to the study area level, and a year-over-year peak load growth rate is generated and presented in the tables below.

Year One Weather-Adjustment (90/10) and Multi-Year Annual Growth Percentage (Summer), after EE, PV, EV, and EH impacts																													
Study Area	Weather Adjustment	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	103.2%	2.0%	1.8%	2.0%	1.4%	2.4%	2.6%	3.3%	4.2%	3.3%	4.3%	4.6%	4.8%	2.9%	3.6%	3.4%	3.8%	3.3%	4.0%	3.5%	2.9%	2.7%	2.9%	1.8%	1.8%	1.2%	0.6%	1.2%	0.7%
Amesbury Newburyport	102.4%	0.9%	0.1%	0.1%	0.3%	2.0%	1.9%	2.2%	2.4%	3.0%	3.0%	3.0%	3.0%	3.5%	3.2%	1.9%	3.2%	3.5%	2.9%	2.0%	1.2%	1.1%	1.3%	1.0%	1.3%	0.9%	0.3%	1.2%	0.9%
Attleboro	102.3%	0.4%	0.1%	0.8%	0.3%	0.4%	1.7%	1.9%	2.1%	3.5%	4.2%	4.0%	2.5%	3.5%	3.6%	3.1%	2.9%	2.6%	2.9%	2.2%	1.5%	1.2%	1.4%	0.8%	1.3%	1.0%	0.4%	1.3%	0.9%
Ayer Clinton	103.2%	-0.1%	2.1%	1.7%	-0.4%	2.0%	3.5%	1.7%	-0.2%	3.3%	2.9%	3.5%	3.7%	3.1%	2.6%	2.3%	2.9%	3.1%	3.9%	2.7%	1.8%	1.5%	1.7%	1.3%	1.6%	0.9%	0.4%	1.2%	0.9%
Barre-Athol	103.2%	1.7%	2.8%	-0.3%	3.1%	3.7%	3.9%	4.4%	3.0%	5.0%	4.3%	5.4%	6.3%	3.7%	3.6%	3.6%	3.5%	2.9%	3.0%	1.8%	1.3%	1.1%	1.3%	1.1%	1.3%	1.0%	0.4%	1.3%	1.0%
Beverly	102.4%	-0.4%	1.2%	1.5%	0.9%	1.8%	0.3%	2.0%	2.0%	2.6%	3.1%	3.3%	3.2%	2.7%	4.2%	2.3%	4.3%	3.0%	2.9%	2.0%	1.6%	1.5%	1.6%	1.4%	1.7%	1.1%	0.4%	1.2%	0.9%
Billerica	103.2%	1.2%	0.3%	1.4%	1.1%	1.7%	1.8%	2.2%	2.4%	2.6%	2.5%	2.7%	3.1%	3.0%	3.2%	2.9%	2.8%	3.4%	3.0%	2.1%	1.2%	1.0%	1.2%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Bridgewater	102.3%	0.1%	-0.9%	0.8%	0.8%	1.5%	1.7%	2.2%	2.7%	3.7%	4.0%	4.3%	4.5%	3.7%	4.1%	2.9%	3.0%	2.5%	3.5%	1.7%	1.1%	1.0%	1.2%	1.0%	1.2%	0.9%	0.3%	1.2%	0.9%
Brockton	102.3%	0.1%	0.4%	0.8%	0.4%	0.7%	1.6%	1.7%	2.1%	2.5%	2.7%	3.5%	3.9%	3.0%	3.9%	2.7%	3.0%	2.9%	2.9%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.4%	1.3%	0.9%
Brockton NW / Randolph	102.3%	-0.8%	0.3%	0.8%	0.5%	1.5%	1.5%	1.8%	2.0%	2.9%	3.6%	3.9%	3.6%	3.1%	3.9%	3.0%	3.0%	2.7%	3.2%	2.3%	1.6%	1.3%	1.4%	1.1%	1.3%	0.9%	0.4%	1.2%	0.9%
Cape Ann	102.4%	1.2%	1.3%	1.5%	1.2%	2.1%	2.1%	3.0%	3.1%	3.4%	3.9%	4.2%	4.0%	4.0%	4.4%	3.6%	4.7%	3.9%	3.1%	1.7%	1.3%	1.1%	1.2%	1.0%	1.2%	0.9%	0.4%	1.1%	0.8%
Chelmsford Westford	103.2%	1.0%	0.4%	1.4%	1.1%	1.9%	1.9%	2.0%	2.2%	2.5%	2.5%	2.3%	2.6%	2.7%	3.9%	2.7%	3.5%	2.6%	2.7%	1.7%	1.7%	1.4%	1.5%	1.3%	1.3%	1.5%	0.8%	1.6%	0.8%
Dracut	102.7%	1.1%	1.2%	1.4%	1.0%	2.0%	-2.2%	2.8%	3.2%	3.4%	3.4%	3.5%	4.2%	3.2%	3.7%	3.4%	2.4%	3.2%	3.3%	1.7%	1.5%	1.4%	1.5%	1.3%	1.3%	1.0%	0.4%	1.2%	0.9%
Everett Malden Medford	102.4%	1.0%	1.2%	1.5%	1.1%	1.8%	1.7%	1.9%	2.0%	2.4%	2.2%	2.2%	2.6%	2.6%	2.7%	2.8%	4.6%	3.5%	4.6%	3.2%	2.7%	2.6%	2.5%	2.0%	2.0%	1.4%	0.8%	1.3%	1.0%
Fall River	102.3%	0.4%	0.4%	0.6%	0.3%	1.2%	1.2%	1.5%	1.7%	1.9%	1.8%	2.0%	2.6%	1.5%	2.3%	2.6%	2.6%	2.4%	2.6%	2.0%	1.3%	1.2%	1.4%	1.2%	1.5%	1.0%	0.4%	1.4%	1.0%
Gardner Winchendon	103.2%	-2.2%	1.6%	1.3%	1.6%	2.1%	5.7%	0.6%	2.1%	3.8%	4.0%	3.7%	5.6%	2.9%	3.4%	3.0%	2.9%	1.1%	3.3%	1.3%	1.3%	1.4%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	1.2%
Hanover	102.3%	0.5%	0.3%	1.1%	0.7%	1.3%	1.6%	1.9%	2.0%	3.0%	4.3%	4.2%	3.4%	4.0%	3.8%	2.7%	2.9%	2.9%	3.5%	1.9%	1.4%	1.0%	1.1%	0.9%	1.3%	0.9%	0.4%	1.0%	0.9%
Haverhill	102.4%	1.0%	0.4%	1.1%	0.8%	-0.3%	1.7%	2.0%	2.1%	2.2%	2.4%	3.1%	3.7%	2.4%	2.9%	2.5%	2.8%	2.5%	3.3%	1.9%	2.8%	2.3%	2.9%	2.3%	2.3%	1.7%	0.9%	1.6%	1.1%
Hopedale East	102.3%	-0.3%	-0.1%	0.7%	0.3%	-0.7%	1.7%	1.6%	2.0%	3.0%	3.0%	3.0%	3.1%	3.3%	2.7%	2.6%	3.6%	2.6%	2.9%	1.9%	0.6%	1.1%	1.3%	1.1%	1.2%	1.0%	0.1%	1.3%	1.1%
Hopedale West	102.3%	0.1%	1.5%	1.4%	1.7%	2.4%	2.9%	2.5%	3.3%	4.0%	4.1%	4.2%	3.8%	3.2%	3.6%	3.3%	3.0%	2.5%	4.2%	2.2%	1.4%	1.0%	1.4%	1.0%	1.2%	0.9%	0.4%	1.2%	1.1%
Lawrence	102.7%	1.0%	1.2%	1.3%	0.8%	1.6%	1.7%	1.7%	1.7%	1.8%	1.8%	1.8%	2.1%	1.5%	2.7%	1.6%	2.2%	1.8%	2.4%	1.7%	1.2%	1.1%	1.4%	1.0%	1.5%	1.1%	0.4%	1.3%	1.1%
Leominster	103.2%	1.8%	1.8%	1.9%	1.4%	1.5%	2.5%	1.4%	2.5%	2.7%	2.6%	2.7%	3.2%	2.1%	2.4%	2.0%	2.6%	2.8%	2.9%	3.4%	2.5%	2.3%	2.3%	1.7%	1.9%	1.3%	0.7%	1.5%	1.3%
Lowell	103.2%	1.1%	1.0%	1.1%	0.8%	1.5%	1.5%	1.5%	1.6%	1.7%	1.7%	2.1%	2.0%	1.4%	3.8%	1.7%	2.2%	2.0%	2.3%	1.7%	3.0%	3.7%	3.1%	2.6%	2.6%	2.2%	1.6%	2.5%	1.6%
Lynn	102.4%	1.0%	1.2%	1.4%	1.0%	1.7%	1.7%	1.8%	1.9%	2.0%	2.0%	2.2%	2.2%	1.6%	2.5%	1.7%	2.4%	2.1%	2.3%	1.8%	1.4%	2.3%	1.6%	1.4%	1.6%	1.2%	0.6%	1.4%	1.1%
Marlboro	103.2%	1.3%	1.5%	1.5%	1.2%	1.8%	1.9%	1.4%	2.0%	1.2%	1.4%	2.4%	3.9%	2.4%	2.8%	1.5%	3.4%	1.9%	3.4%	2.3%	1.7%	1.5%	1.7%	1.0%	1.4%	1.0%	0.4%	1.3%	1.4%
Melrose Saugus	102.4%	1.1%	1.2%	1.5%	1.2%	1.9%	1.8%	2.1%	2.2%	2.5%	2.6%	2.8%	3.0%	3.2%	3.9%	2.8%	3.9%	3.1%	4.0%	2.3%	1.7%	1.7%	1.9%	1.5%	1.7%	1.3%	0.7%	1.3%	0.9%
Methuen	102.7%	1.1%	0.8%	1.4%	-1.4%	1.8%	1.6%	0.0%	2.7%	2.8%	2.8%	3.0%	3.5%	2.9%	3.1%	2.8%	3.0%	2.8%	3.0%	3.5%	2.6%	1.9%	1.7%	1.4%	1.8%	1.5%	0.9%	1.6%	1.0%
Millbury-Grafton	103.2%	0.6%	2.7%	-0.1%	1.5%	2.1%	5.1%	0.9%	2.5%	3.8%	4.1%	3.6%	3.9%	3.3%	4.1%	3.2%	3.6%	2.4%	3.5%	1.7%	1.0%	1.1%	1.2%	0.8%	1.5%	1.1%	0.6%	1.3%	2.0%
Monson-Palmer-Longmeadow	103.2%	1.7%	-0.1%	0.6%	2.2%	2.9%	3.1%	3.5%	3.7%	4.0%	4.1%	5.0%	3.9%	3.4%	4.2%	3.2%	3.2%	2.6%	2.5%	1.5%	1.0%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Nantucket	99.2%	2.2%	1.9%	1.8%	2.0%	2.3%	2.3%	2.2%	2.2%	2.4%	2.4%	2.4%	2.5%	2.4%	2.4%	2.3%	2.2%	2.1%	2.1%	1.7%	1.5%	1.4%	1.2%	1.1%	1.0%	0.9%	0.8%	0.7%	0.7%
North Andover	102.7%	1.1%	1.2%	1.4%	1.1%	1.7%	1.6%	1.8%	2.0%	2.3%	0.8%	2.3%	2.7%	2.5%	2.5%	2.4%	2.4%	2.4%	2.6%	1.7%	1.3%	1.1%	1.3%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
North Lowell	103.2%	1.2%	1.2%	1.4%	1.1%	1.9%	1.8%	2.0%	2.2%	2.4%	2.5%	2.5%	2.8%	2.2%	3.1%	3.2%	3.1%	2.9%	3.8%	2.6%	2.1%	1.8%	1.5%	1.2%	1.5%	1.3%	0.5%	1.7%	1.4%
Northampton-S berkshire	103.2%	1.9%	1.9%	1.9%	0.5%	2.5%	1.7%	2.7%	3.3%	2.3%	3.0%	3.7%	4.6%	2.7%	4.3%	3.1%	4.4%	3.6%	3.3%	2.6%	2.0%	1.8%	1.7%	1.4%	1.3%	0.9%	0.4%	1.2%	0.9%
Pepperell Dunstable	103.2%	0.9%	1.3%	1.7%	-2.9%	2.9%	3.2%	3.8%	4.0%	4.0%	4.0%	3.6%	2.9%	6.4%	4.2%	2.1%	3.5%	3.5%	2.4%	1.2%	0.9%	0.8%	1.0%	0.9%	1.2%	0.8%	0.4%	1.1%	0.8%
Quincy	102.3%	0.3%	0.3%	0.8%	0.4%	1.2%	1.2%	1.4%	1.5%	1.9%	2.1%	2.3%	2.8%	2.3%	3.3%	2.5%	3.4%	5.6%	4.9%	3.9%	3.2%	2.8%	2.5%	2.2%	2.2%	1.4%	0.7%	1.2%	0.9%
Revere Winthrop	102.4%	0.9%	1.2%	1.4%	1.1%	2.0%	1.9%	2.4%	2.4%	2.7%	2.2%	2.1%	2.7%	1.8%	2.3%	3.2%	3.0%	3.9%	3.8%	3.0%	2.4%	3.6%	3.8%	3.4%	3.5%	2.6%	1.7%	2.2%	1.6%
Salem Swampscott	102.4%	1.1%	1.3%	1.5%	1.1%	1.8%	1.8%	2.0%	2.1%	2.5%	2.7%	3.0%	3.6%	3.0%	3.6%	2.7%	3.3%	4.0%	4.0%	3.0%	2.4%	2.2%	2.3%	1.8%	1.7%	1.1%	0.5%	1.2%	0.8%
Scituate	102.3%	0.5%	0.9%	1.5%	1.2%	2.1%	1.8%	2.2%	2.3%	3.1%	3.1%	2.0%	2.7%	5.8%	3.2%	1.4%	1.9%	1.9%	2.2%	1.3%	0.9%	0.8%	1.1%	0.9%	1.2%	0.9%	0.3%	1.2%	0.9%
Somerset	102.3%	0.2%	0.5%	0.8%	0.5%	2.0%	0.9%	2.9%	3.5%	4.1%	4.7%	4.8%	3.3%	3.2%	5.3%	2.6%	2.2%	2.1%	2.6%	1.4%	1.0%	0.9%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Spencer-Rutland	103.2%	0.9%	1.7%	-0.6%	-0.1%	1.7%	5.2%	-1.1%	4.1%	5.2%	4.8%	4.7%	5.8%	3.8%	4.5%	4.3%	3.6%	3.2%	3.6%	1.4%	1.2%	1.0%	1.0%	0.9%	1.1%	0.8%	0.4%	1.1%	0.9%
Tewksbury	102.7%	1.1%	1.2%	0.8%	0.8%	1.9%	1.9%	2.1%	2.3%	2.5%	2.7%	2.8%	2.8%	3.1%	3.8%	2.3%	2.3%	2.6%	2.7%	2.0%	1.4%	1.3%	1.1%	0.9%	1.3%	0.9%	0.4%	1.2%	0.9%
Topsfield	102.4%	1.0%	1.6%	2.0%	2.3%	2.9%	2.9%	3.1%	2.9%	3.0%	2.1%	1.8%	1.6%	5.5%	0.6%	1.6%	2.1%	2.1%	2.4%	1.3%	1.0%	0.9%	1.2%	0.9%	1.2%	0.8%	0.4%	1.2%	0.9%
Webster Southbridge Charlton	103.2%	1.0%	2.4%	-1.4%	1.0%	2.1%	3.9%	1.1%	3.4%	4.0%	4.0%	3.4%	5.7%	2.8%	3.7%	3.3%	3.1%	1.7%	3.6%	1.3%	1.8%	1.5%	1.9%	1.4%	1.5%	1.1%	0.5%	1.3%	1.6%
Weymouth Holbrook	102.3%	0.5%	0.6%	1.0%	0.6%	1.5%	1.5%	1.7%	2.1%	1.6%	4.2%	4.1%	4.0%	4.3%	4.2%	3.3%	3.2%	3.9%	4.4%	2.8%	2.1%	1.7%	1.6%	1.2%	1.4%	0.8%	0.3%	1.1%	0.9%
Worcester North	103.2%	1.3%	2.1%	1.5%	1.5%	2.3%	2.7%	1.8%	2.3%	2.4%	2.5%	2.9%	3.4%	2.1%	2.9%	2.0%	2.4%	3.2%	3.2%	2.3%	1.7%	1.4%	1.7%	1.6%	1.7%	1.2%	0.6%	1.4%	0.9%
Worcester South	103.2%	1.5%	2.1%	1.9%	1.6%	2.2%	2.2%	2.0%	2.3%	2.3%	2.2%	2.4%	2.6%	2.3%	2.4%	1.8%	2.3%	2.0%	2.3%	1.7%	1.5%	1.3%	1.7%	1.7%	1.9%	2.5%	0.9%	1.7%	1.3%

Year One Weather-Adjustment and Multi-Year Annual Growth Percentage (Summer), after EE, EV, and EH impacts

Study Area	Weather Adjustment (90/10)	Weather Adjustment (50/50)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	103.2%	97.7%	2.3%	2.0%	2.1%	1.7%	2.5%	2.7%	3.4%	4.3%	4.2%	4.0%	4.1%	4.4%	2.7%	4.1%	3.4%	3.8%	3.4%	3.9%	3.5%	3.1%	2.8%	2.9%	1.8%	1.8%	1.2%	0.7%	1.2%	0.9%
Amesbury Newburyport	102.4%	94.7%	1.1%	1.3%	1.6%	1.2%	2.0%	1.9%	2.2%	2.3%	2.7%	2.6%	2.6%	2.7%	3.0%	3.2%	1.7%	2.9%	3.9%	3.2%	2.0%	1.3%	1.1%	1.3%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Attleboro	102.3%	93.6%	0.7%	0.6%	1.0%	0.7%	1.7%	1.8%	2.0%	2.2%	3.2%	3.6%	3.5%	2.8%	3.0%	3.7%	3.1%	2.9%	2.9%	2.9%	2.2%	1.5%	1.2%	1.4%	1.1%	1.3%	1.0%	0.4%	1.2%	0.9%
Ayer Clinton	103.2%	97.7%	2.2%	2.0%	2.0%	1.5%	2.2%	2.2%	2.5%	2.7%	2.8%	2.5%	3.0%	3.0%	2.6%	2.3%	2.2%	2.5%	2.6%	4.4%	2.6%	1.8%	1.5%	1.7%	1.3%	1.5%	0.9%	0.4%	1.2%	0.9%
Barre-Athol	103.2%	97.7%	3.9%	3.1%	3.2%	3.3%	3.7%	3.5%	4.2%	4.9%	4.4%	3.9%	4.8%	5.2%	3.2%	3.2%	3.7%	3.4%	2.8%	2.9%	1.8%	1.3%	1.1%	1.3%	1.1%	1.3%	1.0%	0.4%	1.3%	1.0%
Beverly	102.4%	94.7%	1.2%	1.3%	1.5%	1.2%	1.9%	1.8%	2.0%	2.0%	2.2%	2.7%	2.8%	2.8%	2.3%	3.7%	2.0%	3.7%	3.4%	2.9%	2.0%	1.6%	1.5%	1.6%	1.4%	1.7%	1.1%	0.4%	1.2%	0.9%
Billerica	103.2%	97.7%	1.2%	1.2%	1.5%	1.2%	2.0%	1.9%	2.2%	2.5%	2.6%	2.6%	2.7%	3.2%	2.4%	2.9%	2.4%	2.6%	4.1%	3.1%	2.1%	1.3%	1.0%	1.2%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Bridgewater	102.3%	93.6%	0.6%	0.8%	1.0%	1.0%	1.8%	1.8%	2.3%	2.6%	3.2%	3.4%	3.7%	3.9%	3.9%	4.4%	2.9%	3.0%	2.6%	3.5%	1.8%	1.2%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Brockton	102.3%	93.6%	0.5%	0.6%	0.9%	0.6%	1.5%	1.7%	1.8%	2.2%	2.5%	2.8%	2.9%	3.3%	2.6%	3.5%	3.1%	3.0%	2.9%	3.0%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.4%	1.3%	0.9%
Brockton NW / Randolph	102.3%	93.6%	0.6%	0.8%	1.0%	0.7%	1.6%	1.6%	1.9%	2.1%	2.5%	3.1%	3.3%	3.2%	2.7%	4.0%	3.0%	3.0%	2.7%	3.3%	2.3%	1.6%	1.3%	1.4%	1.1%	1.3%	0.9%	0.4%	1.2%	0.9%
Cape Ann	102.4%	94.7%	1.3%	1.5%	1.7%	1.4%	2.2%	2.3%	3.1%	3.2%	3.5%	3.9%	3.8%	3.5%	4.1%	4.5%	3.6%	4.8%	3.9%	3.1%	1.8%	1.4%	1.1%	1.2%	1.0%	1.3%	0.9%	0.4%	1.1%	0.8%
Chelmsford Westford	103.2%	97.7%	1.1%	1.3%	1.5%	1.2%	1.9%	2.0%	2.1%	2.2%	2.5%	2.6%	2.3%	2.6%	2.7%	3.3%	2.3%	3.1%	3.2%	2.8%	1.8%	1.7%	1.4%	1.5%	1.3%	1.6%	1.5%	0.8%	1.6%	1.1%
Dracut	102.7%	95.9%	1.2%	1.3%	1.6%	1.3%	2.1%	2.1%	2.4%	2.7%	2.9%	2.9%	3.0%	3.7%	2.8%	3.3%	3.8%	3.4%	3.2%	3.3%	2.2%	1.4%	1.3%	1.5%	1.3%	1.3%	1.0%	0.4%	1.2%	0.9%
Everett Malden Medford	102.4%	94.7%	1.2%	1.4%	1.6%	1.2%	1.9%	1.8%	2.1%	2.1%	2.4%	2.3%	2.3%	2.7%	2.7%	2.8%	2.2%	4.0%	3.9%	4.6%	3.2%	2.7%	2.6%	2.5%	2.0%	2.0%	1.4%	0.8%	1.3%	1.0%
Fall River	102.3%	93.6%	0.6%	0.6%	0.8%	0.4%	1.3%	1.4%	1.6%	1.8%	2.0%	1.8%	2.0%	2.7%	1.6%	2.4%	1.8%	2.4%	2.1%	2.4%	1.8%	1.2%	1.1%	1.3%	1.1%	1.4%	1.0%	0.3%	1.3%	0.9%
Gardner Winchendon	103.2%	97.7%	2.1%	1.8%	1.9%	2.1%	2.3%	2.4%	2.7%	2.9%	3.3%	3.5%	3.8%	3.6%	2.6%	3.2%	2.6%	3.4%	2.8%	2.8%	1.7%	1.2%	1.4%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Hanover	102.3%	93.6%	0.6%	0.8%	1.3%	1.0%	1.9%	1.7%	2.0%	2.1%	3.1%	3.8%	3.6%	3.0%	4.0%	3.8%	2.7%	3.0%	3.0%	3.5%	1.9%	1.4%	1.0%	1.2%	0.9%	1.3%	0.9%	0.4%	1.2%	0.9%
Haverhill	102.4%	94.7%	1.1%	1.2%	1.4%	1.0%	1.7%	1.7%	2.0%	2.1%	2.2%	2.4%	2.6%	3.2%	2.1%	2.6%	2.2%	2.5%	2.2%	3.0%	2.9%	2.8%	2.3%	2.9%	2.3%	2.3%	1.7%	0.9%	1.6%	1.1%
Hopedale East	102.3%	93.6%	0.8%	0.7%	1.1%	0.6%	1.5%	1.4%	1.7%	2.1%	2.5%	2.5%	2.6%	2.6%	2.7%	2.3%	2.2%	3.9%	2.6%	2.9%	1.9%	1.3%	1.1%	1.3%	1.1%	1.4%	1.0%	0.3%	1.3%	0.9%
Hopedale West	102.3%	93.6%	1.8%	2.2%	2.3%	2.1%	2.9%	2.6%	2.7%	2.9%	3.5%	3.9%	3.7%	3.3%	3.4%	3.4%	3.7%	3.3%	3.1%	4.0%	2.2%	1.5%	1.3%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Lawrence	102.7%	95.9%	1.1%	1.2%	1.4%	0.9%	1.7%	1.7%	1.8%	1.7%	1.8%	1.8%	1.8%	2.1%	1.6%	2.8%	1.6%	2.3%	2.0%	2.2%	1.7%	1.2%	1.1%	1.4%	1.2%	1.5%	1.1%	0.4%	1.3%	1.0%
Leominster	103.2%	97.7%	1.8%	1.9%	2.1%	1.5%	2.3%	2.1%	2.3%	2.5%	2.7%	2.6%	2.8%	3.0%	2.2%	2.4%	2.0%	2.7%	2.3%	2.5%	3.0%	2.2%	3.1%	2.3%	1.8%	1.9%	1.3%	0.7%	1.5%	1.0%
Lowell	103.2%	97.7%	1.1%	1.1%	1.2%	0.9%	1.6%	1.5%	1.6%	1.6%	1.8%	1.7%	2.2%	2.1%	1.4%	3.8%	1.8%	2.3%	2.1%	2.3%	1.7%	3.0%	2.5%	2.7%	3.8%	2.6%	2.2%	1.6%	2.5%	1.6%
Lynn	102.4%	94.7%	1.1%	1.3%	1.5%	1.1%	1.8%	1.7%	1.9%	2.0%	2.0%	2.1%	2.3%	2.3%	1.6%	2.6%	1.8%	2.4%	2.1%	2.3%	1.9%	1.4%	1.3%	1.5%	1.3%	1.5%	1.1%	0.5%	1.3%	1.0%
Marlboro	103.2%	97.7%	1.4%	1.5%	1.7%	1.3%	2.1%	1.7%	1.8%	2.0%	2.3%	2.4%	2.4%	2.5%	2.4%	2.9%	1.8%	2.6%	2.3%	2.8%	2.0%	1.5%	1.3%	1.5%	2.2%	1.4%	1.0%	0.4%	1.3%	0.9%
Melrose Saugus	102.4%	94.7%	1.2%	1.4%	1.6%	1.3%	2.0%	2.0%	2.2%	2.3%	2.6%	2.7%	3.0%	3.1%	2.8%	3.5%	2.4%	4.3%	3.2%	4.0%	2.3%	1.7%	1.7%	1.9%	1.5%	1.8%	1.3%	0.7%	1.3%	0.9%
Methuen	102.7%	95.9%	1.2%	1.3%	1.5%	1.1%	1.9%	1.8%	2.1%	2.3%	2.5%	2.5%	2.6%	3.1%	2.5%	2.7%	2.4%	2.7%	2.5%	3.6%	3.4%	2.5%	1.9%	1.7%	1.4%	1.8%	1.4%	0.9%	1.6%	1.0%
Millbury-Grafton	103.2%	97.7%	1.9%	2.0%	2.2%	1.9%	2.5%	2.6%	2.9%	2.8%	3.3%	3.6%	3.5%	3.0%	2.9%	3.8%	3.4%	3.6%	3.4%	3.0%	1.7%	1.2%	1.1%	1.2%	1.2%	1.5%	1.1%	0.6%	1.3%	0.9%
Monson-Palmer-Longmeadow	103.2%	97.7%	2.2%	2.0%	2.2%	2.1%	2.8%	2.9%	3.2%	3.3%	3.7%	3.8%	4.4%	3.5%	3.0%	4.5%	3.3%	3.2%	2.7%	2.8%	1.6%	1.1%	1.0%	1.3%	1.0%	1.2%	0.9%	0.4%	1.2%	0.9%
Nantucket	99.2%	89.1%	2.3%	2.0%	1.8%	2.1%	2.3%	2.3%	2.2%	2.1%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%	2.0%	2.0%	1.9%	1.6%	1.5%	1.3%	1.2%	1.1%	1.0%	0.9%	0.8%	0.7%	0.6%
North Andover	102.7%	95.9%	1.2%	1.3%	1.5%	1.1%	1.8%	1.7%	1.8%	2.1%	2.3%	2.2%	2.3%	2.7%	2.5%	2.5%	1.7%	2.6%	2.1%	2.3%	1.6%	1.1%	1.0%	1.2%	0.9%	1.3%	0.9%	0.3%	1.2%	0.9%
North Lowell	103.2%	97.7%	1.3%	1.3%	1.5%	1.1%	2.0%	1.9%	2.1%	2.3%	2.5%	2.5%	2.6%	2.9%	2.3%	3.2%	2.5%	2.8%	3.5%	3.8%	2.6%	2.1%	1.9%	1.5%	1.3%	1.5%	1.3%	0.5%	1.7%	1.4%
Northampton-S berkshire	103.2%	97.7%	2.0%	2.0%	2.1%	1.8%	2.5%	2.6%	2.7%	3.3%	3.1%	3.3%	3.9%	4.0%	2.3%	3.8%	2.7%	5.6%	3.7%	3.7%	2.5%	1.9%	1.8%	1.7%	1.4%	1.3%	0.9%	0.4%	1.2%	0.9%
Pepperell Dunstable	103.2%	97.7%	1.0%	1.5%	1.9%	1.7%	2.6%	2.8%	3.3%	3.4%	3.4%	3.5%	3.2%	2.6%	6.2%	4.2%	3.7%	3.4%	3.3%	2.4%	1.2%	0.9%	0.8%	1.0%	0.9%	1.2%	0.8%	0.3%	1.1%	0.8%
Quincy	102.3%	93.6%	0.5%	0.6%	0.9%	0.6%	1.4%	1.4%	1.5%	1.6%	2.0%	2.2%	2.4%	2.9%	2.4%	2.8%	2.1%	3.0%	5.9%	4.9%	3.9%	3.2%	2.8%	2.5%	2.2%	2.2%	1.4%	0.7%	1.2%	0.9%
Revere Winthrop	102.4%	94.7%	1.1%	1.3%	1.6%	1.2%	2.1%	2.1%	2.5%	2.5%	2.8%	2.3%	2.3%	2.8%	1.9%	2.3%	2.4%	2.7%	3.5%	4.4%	3.0%	2.4%	3.6%	3.8%	3.4%	3.4%	2.6%	1.7%	2.2%	1.6%
Salem Swampscott	102.4%	94.7%	1.2%	1.4%	1.6%	1.3%	2.0%	1.9%	2.1%	2.2%	2.6%	2.7%	3.0%	3.6%	2.6%	3.3%	2.4%	3.6%	4.0%	4.0%	3.0%	2.4%	2.2%	2.3%	1.8%	1.7%	1.1%	0.5%	1.2%	0.8%
Scituate	102.3%	93.6%	0.6%	1.0%	1.6%	1.3%	2.2%	2.1%	2.2%	2.4%	3.2%	3.1%	2.1%	2.3%	5.6%	3.3%	1.5%	2.0%	1.9%	2.3%	1.3%	0.9%	0.8%	1.1%	0.9%	1.3%	0.9%	0.3%	1.2%	0.9%
Somerset	102.3%	93.6%	0.6%	0.7%	1.0%	0.9%	2.3%	2.3%	2.8%	2.9%	3.6%	4.0%	4.1%	3.5%	3.2%	5.3%	2.6%	2.4%	2.2%	2.6%	1.4%	1.1%	0.9%	1.2%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Spencer-Rutland	103.2%	97.7%	1.8%	1.3%	1.5%	2.0%	2.2%	2.4%	3.1%	3.3%	4.5%	4.1%	4.3%	4.4%	4.1%	4.4%	4.2%	3.9%	3.1%	3.3%	1.6%	1.1%	0.9%	1.0%	0.9%	1.1%	0.8%	0.4%	1.1%	0.9%
Tewksbury	102.7%	95.9%	1.1%	1.3%	1.5%	1.2%	1.9%	1.9%	2.1%	2.3%	2.5%	2.7%	2.8%	2.8%	3.1%	2.9%	2.0%	2.1%	3.3%	2.8%	2.1%	1.4%	1.3%	1.1%	1.0%	1.3%	0.9%	0.4%	1.2%	0.9%
Topsfield	102.4%	94.7%	1.0%	1.7%	2.1%	2.4%	3.0%	2.9%	3.2%	2.9%	3.1%	2.1%	1.8%	1.6%	4.9%	4.3%	1.6%	2.1%	2.1%	2.3%	1.4%	1.0%	0.9%	1.2%	0.9%	1.2%	0.8%	0.3%	1.2%	0.9%
Webster Southbridge Charlton	103.2%	97.7%	2.1%	1.9%	2.0%	1.7%	2.5%	2.5%	2.7%	3.0%	3.4%	3.5%	3.8%	3.6%	2.7%	3.4%	3.7%	3.3%	2.9%	3.0%	1.8%	1.7%	1.5%	1.8%	1.4%	1.5%	1.1%	0.5%	1.3%	0.9%
Weymouth Holbrook	102.3%	93.6%	0.7%	0.9%	1.2%	0.8%	1.6%	1.7%	1.9%	2.2%	2.7%	3.6%	3.6%	3.5%	4.2%	4.3%	3.3%	3.3%	3.9%	4.4%	2.8%	2.1%	1.7%	1.6%	1.2%	1.4%	0.8%	0.3%	1.1%	0.9%
Worcester North	103.2%	97.7%	1.7%	2.0%	2.1%	1.7%	2.4%	2.2%	2.3%	2.3%	2.4%	2.5%	3.0%	3.1%	2.1%	2.9%	2.1%	2.4%	2.6%	3.0%	2.1%	1.5%	2.1%	1.7%	1.4%	1.7%	1.2%	0.6%	1.4%	1.1%
Worcester South	103.2%	97.7%	1.8%	2.0%	2.1%	1.6%	2.3%	2.1%	2.2%	2.3%	2.3%	2.3%	2.4%	2.6%	2.3%	2.5%	1.9%	2.4%	2.1%	2.3%	1.7%	1.5%	1.3%	1.7%	1.7%	1.9%	1.4%	0.7%	1.6%	1.3%

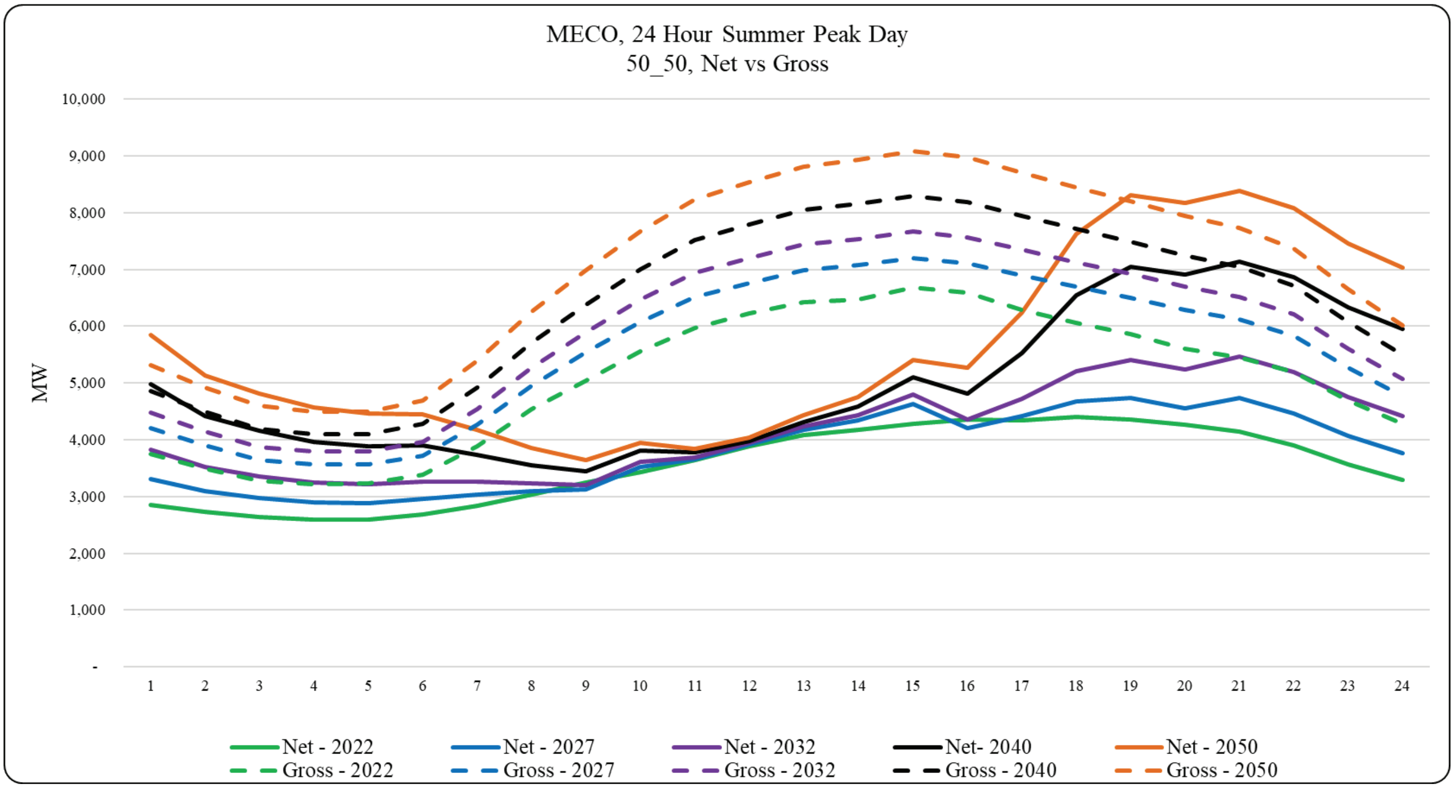
Year One Weather-Adjustment (90/10) and Multi-Year Annual Growth Percentage (Winter), after EE, PV, EV, and EH impacts																														
Study Area	Weather Adjustment	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adams/Deerfield	102.7%	2.3%	2.3%	2.5%	2.2%	3.1%	4.4%	5.2%	6.5%	6.7%	7.2%	8.0%	7.8%	5.3%	6.8%	6.9%	6.5%	6.1%	6.2%	5.8%	5.1%	4.7%	3.4%	5.4%	3.7%	2.7%	1.7%	-0.1%	2.0%	0.27%
Amesbury Newburyport	105.1%	1.3%	1.6%	2.2%	2.2%	3.0%	3.5%	4.0%	4.3%	5.2%	5.5%	5.9%	6.3%	7.2%	7.2%	5.2%	5.7%	8.0%	6.2%	4.5%	3.4%	3.0%	1.6%	4.3%	3.1%	2.3%	1.4%	0.0%	2.1%	0.33%
Attleboro	103.2%	0.9%	0.9%	1.6%	1.7%	2.9%	3.9%	4.1%	4.6%	6.8%	8.1%	8.3%	6.6%	7.5%	7.5%	7.6%	5.5%	7.6%	6.1%	5.1%	4.2%	3.0%	1.2%	3.5%	1.9%	1.5%	0.9%	-0.1%	2.1%	0.33%
Ayer Clinton	102.7%	2.6%	2.7%	2.6%	2.2%	3.0%	3.1%	3.7%	4.1%	4.5%	4.7%	5.8%	5.5%	5.7%	5.0%	5.2%	5.2%	5.5%	5.7%	4.4%	3.5%	2.9%	1.9%	2.1%	1.9%	1.2%	0.7%	0.7%	1.4%	0.27%
Barre-Athol	102.7%	4.0%	3.5%	3.5%	3.7%	4.4%	5.6%	6.5%	7.3%	7.3%	8.1%	10.2%	8.4%	5.8%	7.0%	6.2%	5.7%	3.1%	3.8%	2.5%	1.9%	1.7%	1.7%	1.5%	1.5%	1.2%	0.7%	1.0%	1.0%	0.27%
Beverly	105.1%	1.6%	1.7%	2.2%	2.1%	3.1%	2.9%	3.4%	3.5%	4.1%	5.6%	6.2%	6.1%	6.0%	7.9%	5.7%	7.6%	7.0%	6.2%	5.1%	4.4%	3.8%	1.4%	3.2%	2.1%	1.4%	0.8%	-0.3%	2.2%	0.33%
Billerica	102.7%	1.4%	1.4%	2.0%	2.0%	2.9%	3.5%	3.9%	4.6%	5.1%	5.2%	5.6%	7.5%	6.2%	6.5%	6.6%	4.6%	8.1%	6.0%	4.5%	3.5%	3.0%	1.3%	4.0%	2.4%	1.9%	1.2%	-0.2%	2.3%	0.27%
Bridgewater	103.2%	0.6%	1.2%	1.7%	2.3%	3.2%	3.9%	4.8%	5.4%	6.8%	7.9%	8.8%	8.5%	8.2%	8.8%	7.1%	4.9%	7.4%	6.7%	4.4%	3.9%	2.9%	1.6%	3.6%	2.3%	1.7%	1.1%	-0.1%	2.0%	0.33%
Brockton	103.2%	0.5%	0.8%	1.3%	1.2%	2.1%	3.0%	3.1%	3.8%	4.6%	5.4%	6.0%	6.8%	6.0%	7.1%	5.8%	5.4%	6.8%	5.7%	4.3%	3.8%	3.0%	2.0%	3.8%	2.5%	2.0%	1.3%	0.4%	1.8%	0.33%
Brockton NW / Randolph	103.2%	0.7%	1.0%	1.6%	1.5%	2.4%	3.2%	3.6%	3.9%	4.8%	6.4%	7.1%	7.1%	6.7%	7.6%	7.0%	5.2%	7.3%	6.6%	5.4%	4.6%	4.1%	2.3%	4.0%	2.3%	1.9%	1.4%	-0.1%	2.1%	0.33%
Cape Ann	105.1%	1.7%	2.1%	2.4%	2.2%	3.5%	3.2%	4.7%	4.7%	5.6%	6.9%	7.2%	5.6%	7.6%	8.0%	7.1%	6.2%	8.8%	5.8%	4.5%	3.7%	2.7%	0.4%	3.0%	1.6%	1.3%	0.7%	-0.3%	2.1%	0.33%
Chelmsford Westford	102.7%	1.3%	1.7%	2.1%	2.1%	2.8%	3.2%	3.4%	3.8%	4.5%	4.9%	4.6%	6.6%	6.6%	7.1%	6.0%	6.0%	6.6%	5.6%	4.1%	4.2%	3.6%	1.9%	4.8%	3.2%	2.9%	2.1%	0.7%	2.5%	0.27%
Dracut	104.0%	1.3%	1.5%	2.3%	2.3%	3.2%	4.0%	4.6%	5.3%	5.9%	6.1%	6.4%	9.4%	7.8%	8.2%	8.0%	5.5%	8.6%	6.7%	5.0%	4.1%	3.8%	2.2%	4.3%	2.5%	1.9%	1.3%	0.1%	2.0%	0.31%
Everett Malden Medford	105.1%	1.3%	1.6%	2.1%	1.9%	2.6%	3.0%	3.3%	3.5%	4.3%	4.4%	4.6%	6.4%	6.5%	6.4%	6.1%	7.9%	7.2%	7.9%	6.2%	5.4%	5.0%	3.4%	6.1%	4.2%	3.4%	2.3%	0.8%	2.1%	0.33%
Fall River	103.2%	0.5%	0.5%	1.0%	0.7%	1.5%	2.6%	2.8%	3.3%	3.6%	3.6%	4.1%	7.7%	5.4%	6.4%	6.0%	6.2%	5.8%	6.0%	5.1%	4.4%	4.0%	4.1%	2.7%	2.9%	2.2%	1.4%	2.0%	0.5%	0.33%
Gardner Winchendon	102.7%	2.3%	2.0%	2.3%	2.5%	2.8%	3.6%	3.9%	4.1%	5.1%	6.1%	7.1%	6.0%	5.5%	6.1%	4.6%	6.9%	4.5%	5.3%	3.4%	2.0%	2.0%	2.1%	1.1%	1.5%	1.2%	0.7%	1.4%	0.6%	0.27%
Hanover	103.2%	0.6%	1.3%	2.3%	2.3%	3.1%	4.0%	4.2%	4.4%	6.8%	8.7%	8.4%	7.2%	9.0%	8.0%	6.7%	4.7%	8.2%	6.9%	4.7%	4.1%	3.5%	1.7%	3.9%	2.9%	2.3%	1.6%	0.2%	1.9%	0.33%
Haverhill	105.1%	1.1%	1.3%	1.6%	1.5%	2.2%	3.1%	3.5%	3.7%	4.1%	4.7%	5.4%	8.3%	5.9%	6.5%	6.2%	5.7%	6.0%	6.9%	5.1%	6.0%	5.1%	3.7%	6.1%	4.0%	3.2%	2.2%	0.9%	2.4%	0.33%
Hopedale East	103.2%	1.4%	1.6%	2.2%	1.4%	2.6%	2.0%	2.8%	3.4%	4.4%	4.9%	5.2%	5.7%	6.1%	5.2%	5.5%	6.0%	5.5%	5.3%	4.1%	3.0%	2.6%	1.9%	3.1%	2.0%	1.6%	1.0%	0.4%	1.7%	0.33%
Hopedale West	103.2%	2.5%	3.1%	3.6%	3.7%	5.4%	3.0%	4.0%	4.3%	5.9%	7.2%	7.5%	6.4%	7.1%	6.8%	6.0%	6.4%	5.6%	6.3%	3.6%	2.7%	2.2%	0.7%	3.4%	1.5%	1.2%	0.7%	-0.4%	2.3%	0.33%
Lawrence	104.0%	1.1%	1.2%	1.4%	1.0%	1.6%	2.4%	2.2%	2.2%	2.7%	2.5%	2.8%	4.7%	3.9%	5.3%	-0.3%	9.5%	-3.6%	7.0%	3.5%	3.0%	10.3%	0.3%	2.3%	5.1%	1.9%	0.7%	4.1%	0.2%	0.31%
Leominster	102.7%	1.9%	2.0%	2.4%	2.0%	2.8%	3.1%	3.4%	3.8%	4.4%	4.7%	5.4%	5.5%	5.1%	5.2%	4.8%	5.4%	4.9%	5.1%	5.8%	4.8%	3.4%	2.9%	2.3%	2.2%	1.6%	1.1%	1.0%	1.5%	0.27%
Lowell	102.7%	1.1%	1.1%	1.2%	1.1%	1.7%	2.3%	2.2%	2.3%	2.6%	2.7%	3.5%	4.7%	3.8%	7.0%	4.7%	4.9%	5.1%	5.2%	4.5%	6.3%	5.0%	5.9%	4.8%	4.5%	3.4%	2.3%	1.0%	3.2%	0.27%
Lynn	105.1%	1.2%	1.4%	1.4%	1.4%	2.0%	2.2%	2.3%	2.5%	2.7%	3.0%	3.5%	4.1%	3.6%	4.7%	4.1%	4.7%	4.4%	4.7%	4.2%	3.8%	3.6%	4.0%	2.9%	2.6%	1.6%	1.0%	1.8%	0.6%	0.33%
Marlboro	102.7%	1.6%	2.0%	2.3%	2.6%	3.8%	1.8%	2.5%	2.8%	3.7%	4.1%	4.4%	5.1%	5.3%	5.8%	4.6%	5.0%	4.9%	5.3%	3.9%	3.2%	2.5%	2.6%	1.7%	1.7%	1.3%	0.8%	0.9%	1.2%	0.27%
Melrose Saugus	105.1%	1.4%	1.8%	2.2%	2.2%	3.0%	3.3%	3.7%	4.0%	4.7%	5.4%	6.1%	7.2%	6.9%	7.7%	6.6%	7.0%	7.7%	7.4%	5.4%	4.7%	4.6%	2.6%	4.9%	3.5%	2.7%	1.9%	0.3%	2.1%	0.33%
Methuen	104.0%	1.3%	1.4%	1.8%	1.8%	2.6%	3.5%	3.9%	4.5%	4.9%	5.2%	5.8%	8.3%	7.1%	6.9%	6.9%	6.2%	7.4%	6.6%	7.0%	5.8%	4.6%	2.4%	4.7%	3.3%	2.6%	1.9%	0.7%	2.2%	0.31%
Millbury-Grafton	102.7%	2.3%	2.6%	3.5%	3.3%	4.0%	3.6%	4.6%	4.5%	5.8%	6.9%	7.2%	6.2%	6.7%	7.8%	6.4%	6.7%	7.1%	6.0%	3.8%	2.7%	2.4%	1.4%	2.7%	1.8%	1.5%	1.0%	0.3%	1.9%	0.27%
Monson-Palmer-Longmeadow	102.7%	2.4%	2.3%	2.7%	2.8%	3.6%	4.3%	4.8%	4.9%	5.8%	6.7%	8.0%	6.2%	5.2%	7.2%	6.4%	5.8%	5.3%	4.7%	2.8%	2.2%	1.9%	1.5%	2.3%	1.7%	1.4%	0.8%	0.6%	1.4%	0.27%
Nantucket	114.0%	2.4%	2.2%	2.1%	2.5%	2.8%	3.0%	3.1%	3.1%	3.6%	3.9%	4.1%	4.4%	4.4%	4.4%	4.3%	4.2%	4.1%	4.0%	3.2%	2.9%	2.6%	2.3%	2.0%	1.7%	1.4%	1.2%	0.9%	0.7%	1.75%
North Andover	104.0%	1.4%	1.6%	1.9%	1.8%	2.6%	2.5%	3.0%	3.5%	4.1%	4.2%	4.6%	6.1%	5.9%	5.5%	4.7%	5.0%	5.4%	5.0%	4.0%	3.5%	3.2%	2.2%	2.9%	2.5%	1.9%	1.1%	0.9%	1.4%	0.31%
North Lowell	102.7%	1.5%	1.4%	2.0%	1.8%	2.7%	3.3%	3.6%	4.1%	4.7%	4.9%	5.2%	7.9%	6.4%	7.7%	7.4%	6.2%	7.9%	7.5%	6.2%	5.4%	5.1%	2.8%	5.1%	3.5%	3.2%	1.7%	0.6%	2.6%	0.27%
Northampton-S berkshire	102.7%	2.1%	2.3%	2.6%	2.5%	3.3%	4.0%	4.3%	5.2%	5.4%	6.2%	7.8%	7.6%	5.8%	7.5%	5.9%	8.5%	7.1%	6.7%	4.6%	3.7%	3.5%	1.6%	4.1%	2.0%	1.5%	1.0%	-0.2%	2.3%	0.27%
Pepperell Dunstable	102.7%	1.6%	2.4%	3.1%	3.6%	5.1%	4.4%	5.7%	5.9%	6.4%	7.3%	7.0%	6.3%	11.3%	8.1%	7.6%	5.1%	8.2%	4.8%	3.5%	3.2%	2.9%	1.2%	4.4%	3.1%	1.7%	0.8%	-0.2%	1.9%	0.27%
Quincy	103.2%	0.3%	0.6%	1.4%	1.1%	1.8%	2.6%	2.6%	2.9%	3.8%	4.5%	5.1%	6.8%	6.4%	6.8%	6.4%	7.0%	10.2%	9.2%	7.7%	6.9%	6.3%	4.1%	5.8%	2.9%	1.9%	1.2%	0.0%	2.1%	0.33%
Revere Winthrop	105.1%	1.2%	1.6%	2.0%	1.9%	2.9%	3.4%	4.0%	4.1%	4.7%	4.3%	4.6%	6.8%	5.4%	6.2%	6.7%	7.0%	7.5%	7.0%	6.7%	6.0%	7.1%	5.3%	7.8%	5.7%	3.7%	2.6%	1.4%	2.6%	0.33%
Salem Swampscott	105.1%	1.4%	1.8%	2.2%	2.1%	2.9%	3.1%	3.4%	3.7%	4.6%	5.4%	6.2%	7.9%	6.5%	7.0%	6.9%	6.9%	8.5%	7.6%	6.4%	5.6%	5.3%	3.9%	5.0%	2.8%	1.9%	1.0%	-0.1%	2.0%	0.33%
Scituate	103.2%	0.5%	1.8%	3.4%	3.4%	4.0%	5.5%	5.1%	5.3%	7.4%	7.6%	5.7%	6.1%	13.3%	7.4%	4.8%	3.2%	6.4%	5.1%	3.6%	3.3%	3.1%	1.6%	4.2%	2.9%	2.2%	1.4%	-0.8%	2.8%	0.33%
Somerset	103.2%	0.6%	0.9%	1.6%	2.0%	3.8%	4.9%	5.7%	5.8%	7.2%	8.2%	8.8%	7.4%	7.4%	10.0%	6.2%	3.6%	6.7%	5.4%	3.8%	3.5%	3.1%	1.7%	4.0%	2.7%	1.9%	1.2%	0.0%	2.0%	0.33%
Spencer-Rutland	102.7%	1.7%	1.8%	1.9%	2.5%	2.8%	3.3%	3.9%	4.1%	5.8%	6.0%	6.7%	3.9%	6.4%	6.7%	6.5%	4.0%	7.0%	4.9%	2.6%	1.8%	1.6%	-0.1%	3.1%	1.4%	1.1%	0.7%	-0.6%	2.5%	0.27%
Tewksbury	104.0%	1.3%	1.6%	1.9%	1.8%	2.6%	3.0%	3.4%	3.8%	4.3%	4.9%	5.2%	5.9%	6.5%	5.8%	4.5%	4.1%	5.7%	5.1%	4.1%	3.4%	3.2%	1.4%	3.5%	2.3%	1.8%	1.2%	0.5%	1.9%	0.31%
Topsfield	105.1%	1.6%	3.0%	4.2%	5.3%	5.9%	5.6%	6.2%	5.7%	6.2%	4.8%	4.7%	4.3%	11.8%	8.7%	5.1%	3.7%	7.3%	4.8%	3.4%	3.1%	2.8%	1.7%	3.1%	1.5%	1.2%	0.8%	-0.4%	2.3%	0.33%
Webster Southbridge Charlton	102.7%	2.4%	2.4%	2.6%	2.5%	3.4%	3.3%	3.8%	4.1%	5.1%	5.9%	6.8%	6.2%	5.6%	6.3%	5.0%	6.6%	4.4%	4.8%	3.4%	2.8%	2.3%	2.2%	2.1%	1.8%	1.3%	0.8%	-0.4%	2.6%	0.27%
Weymouth Holbrook	103.2%	0.7%	1.3%	1.9%	1.7%	2.5%	3.3%	3.6%	4.2%	5.4%	7.4%	7.7%	7.6%	8.5%	8.6%	7.6%	5.2%	9.6%	8.2%	6.1%	5.4%	4.8%	2.5%	3.3%	2.0%	1.4%	0.8%	-0.1%	2.0%	0.33%
Worcester North	102.7%	1.7%	2.0%	2.4%	2.1%	2.6%	3.1%	3.1%	3.2%	3.5%	3.9%	4.9%	5.5%	4.4%	5.5%	4.7%	4.5%	5.6%	5.6%	3.9%	4.0%	3.7%	3.9%	2.9%	2.4%	1.9%	1.1%	1.3%	1.2%	0.27%
Worcester South	102.7%	1.8%	1.9%	2.3%	1.9%	2.4%	2.8%	2.8%	3.0%	3.3%	3.4%	3.9%	4.7%	4.7%	4.8%	4.4%	4.7%	4.7%	4.9%	4.2%	4.0%	3.7%	4.0%	3.3%	3.0%	2.0%	1.2%	1.8%	1.2%	0.27%

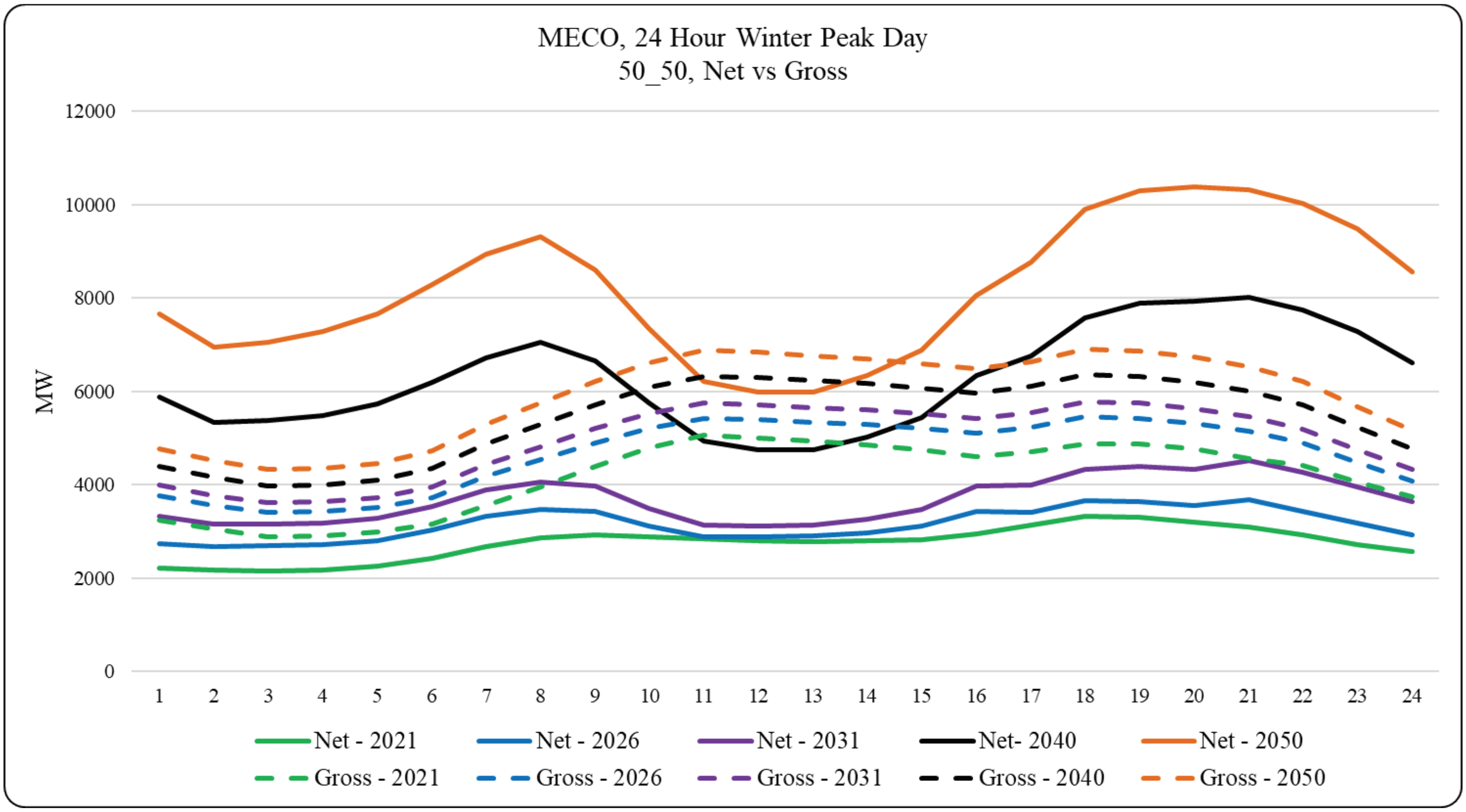
Appendix D: Historical Summer Peaks Days and Hours

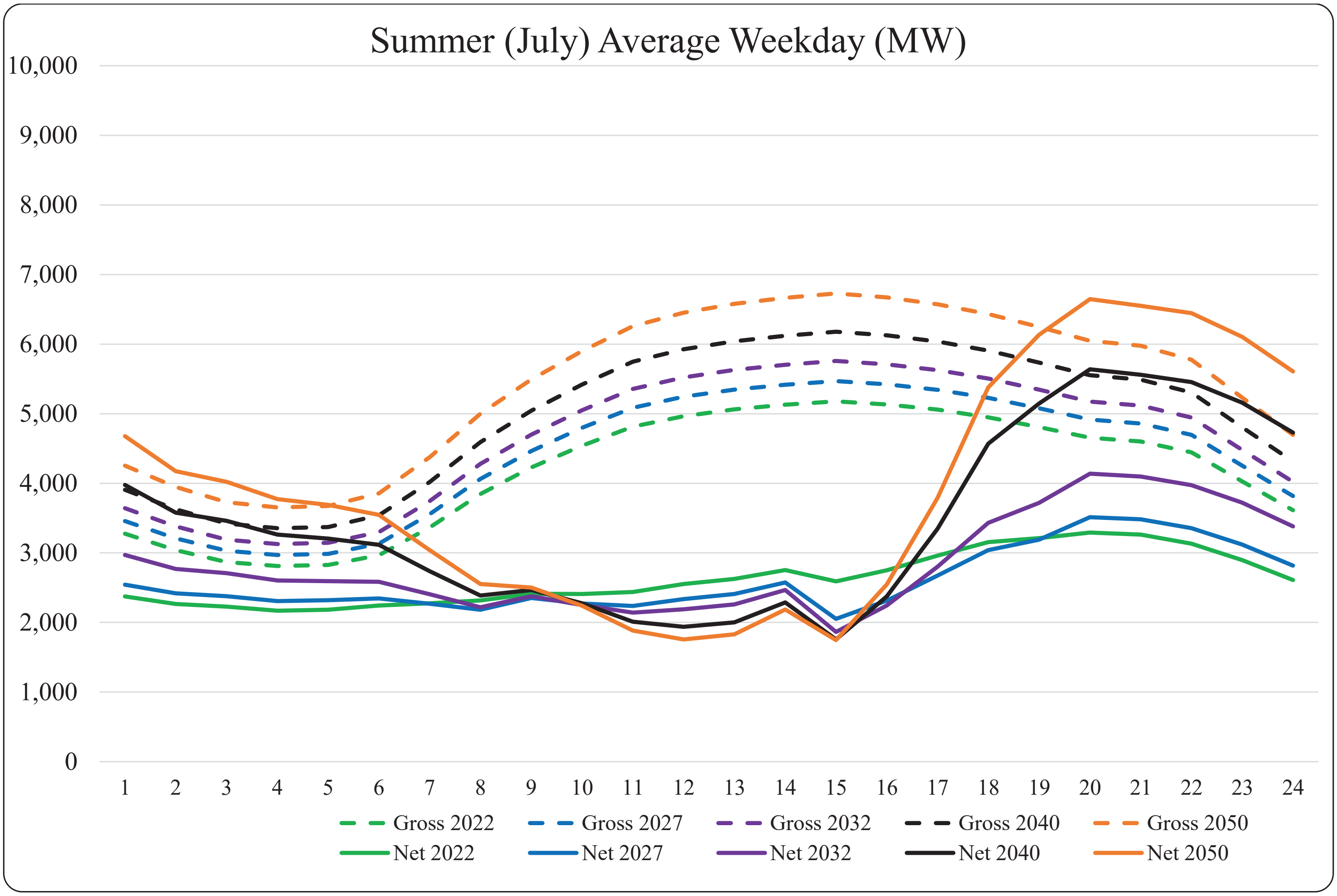
year	dt_wcma	hr_wcma	dt_nema	hr_nema	dt_sema	hr_sema	dt_ma	hr_ma	dt_nant	hr_nant	dt_meco	hr_meco
2003	6/27/2003	14	8/22/2003	16	8/22/2003	15	8/22/2003	15	8/8/2003	19	6/27/2003	14
2004	8/30/2004	16	8/3/2004	17	8/30/2004	16	8/30/2004	16	8/20/2004	20	8/30/2004	16
2005	7/27/2005	15	7/27/2005	17	7/27/2005	16	7/27/2005	16	8/5/2005	19	7/27/2005	16
2006	8/2/2006	15	8/2/2006	17	8/2/2006	16	8/2/2006	16	8/3/2006	19	8/2/2006	16
2007	6/27/2007	15	6/27/2007	16	8/3/2007	15	6/27/2007	15	8/3/2007	19	6/27/2007	15
2008	6/10/2008	17	6/10/2008	18	6/10/2008	17	6/10/2008	17	8/2/2008	19	6/10/2008	17
2009	8/18/2009	14	8/18/2009	14	8/18/2009	15	8/18/2009	14	8/21/2009	19	8/18/2009	14
2010	7/7/2010	15	7/6/2010	15	7/6/2010	17	7/6/2010	15	8/6/2010	18	7/6/2010	15
2011	7/22/2011	14	7/22/2011	15	7/22/2011	16	7/22/2011	15	7/22/2011	19	7/22/2011	15
2012	7/17/2012	17	7/17/2012	18	7/17/2012	16	7/17/2012	17	8/4/2012	19	7/17/2012	17
2013	7/19/2013	15	7/19/2013	17	7/19/2013	15	7/19/2013	15	7/19/2013	18	7/19/2013	15
2014	7/2/2014	15	7/2/2014	16	9/2/2014	16	7/2/2014	16	7/3/2014	19	7/2/2014	16
2015	9/8/2015	17	9/9/2015	17	7/20/2015	18	7/20/2015	17	7/29/2015	18	7/20/2015	17
2016	8/12/2016	15	8/12/2016	16	8/12/2016	16	8/12/2016	15	8/14/2016	18	8/12/2016	15
2017	6/13/2017	17	6/13/2017	17	6/13/2017	18	6/13/2017	17	7/20/2017	19	6/13/2017	17
2018	8/29/2018	18	8/29/2018	18	8/29/2018	18	8/29/2018	18	8/6/2018	18	8/29/2018	18
2019	7/30/2019	19	7/30/2019	18	7/21/2019	18	7/30/2019	18	7/21/2019	18	7/30/2019	18
2020	7/27/2020	18	7/27/2020	18	7/27/2020	18	7/27/2020	18	7/28/2020	19	7/27/2020	18
2021	6/29/2021	18	6/30/2021	17	6/30/2021	18	6/29/2021	18	8/13/2021	18	6/29/2021	18
2022	8/4/2022	18	8/8/2022	18	8/9/2022	15	8/8/2022	18	8/6/2022	18	8/8/2022	18

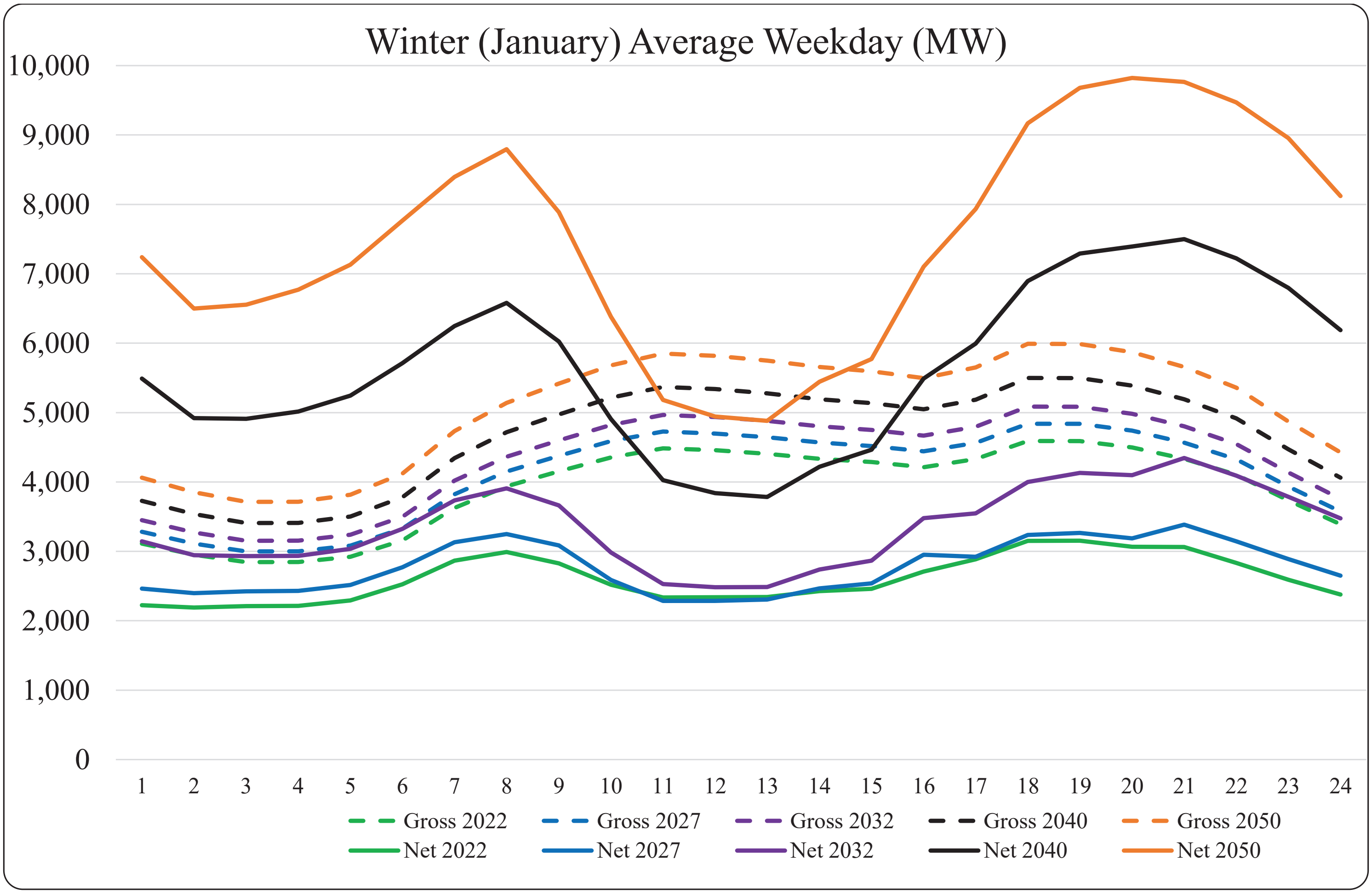
Appendix E: Load Shapes for Typical Day Types

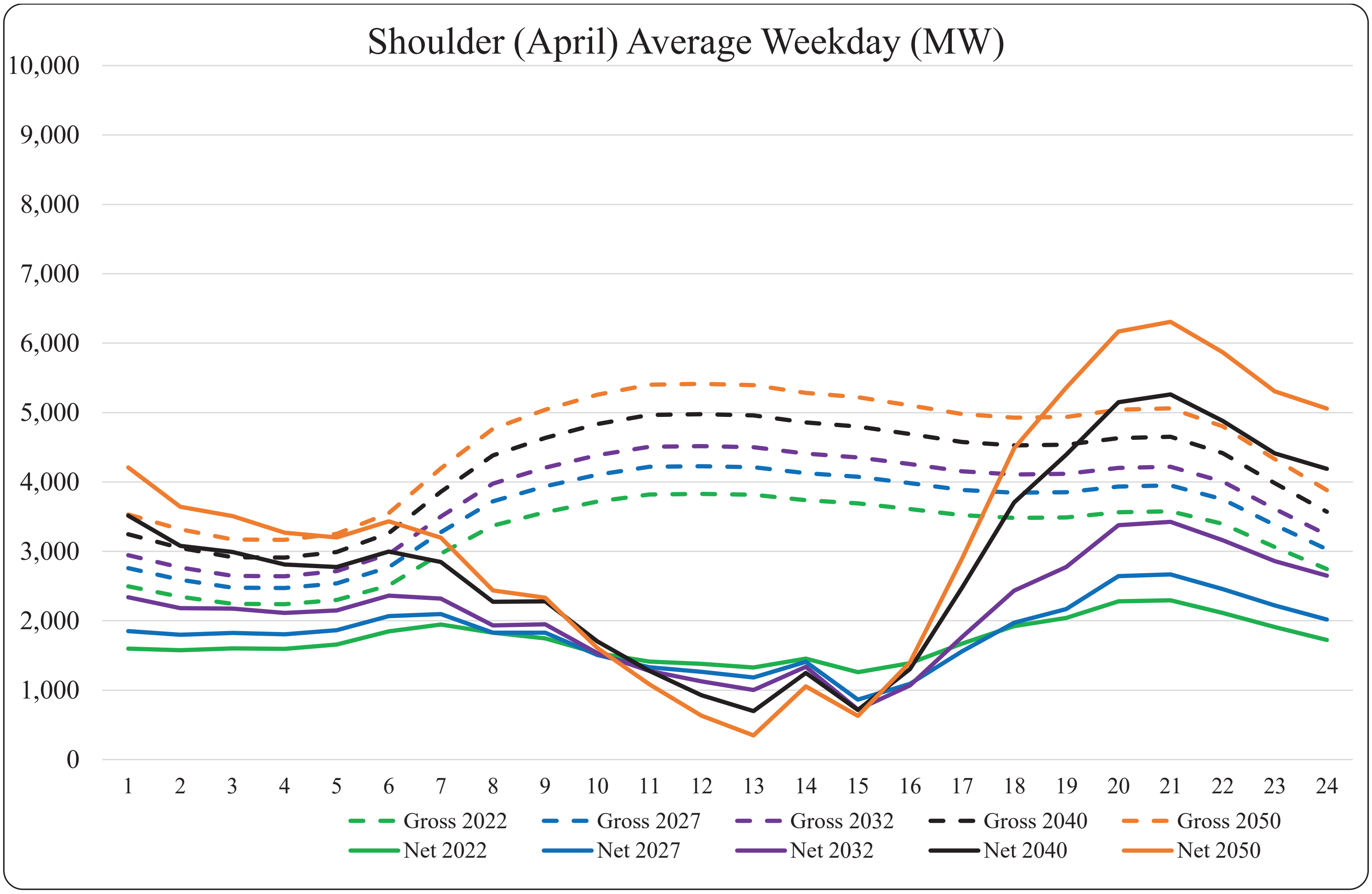
(for Base Case)


MECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2022
Gross - 2022
Net - 2027
Gross - 2027
Net - 2032
Gross - 2032
Net- 2040
Gross - 2040
Net - 2050
Gross - 2050

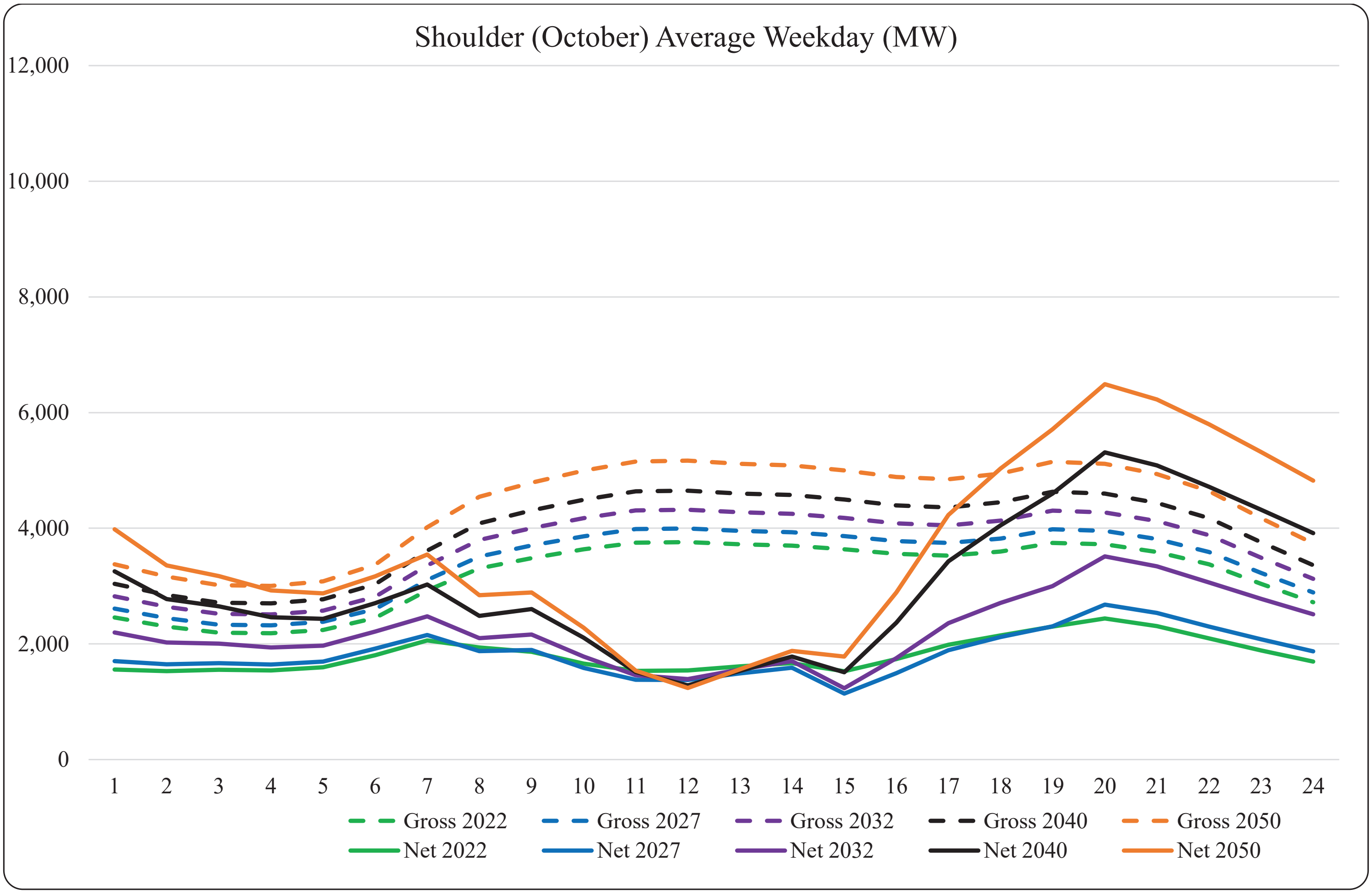

MECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
12000
10000
8000
6000
4000
2000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2021
Net - 2026
Net - 2031
Net- 2040
Net - 2050
Gross - 2021
Gross - 2026
Gross - 2031
Gross - 2040
Gross - 2050


Summer (July) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

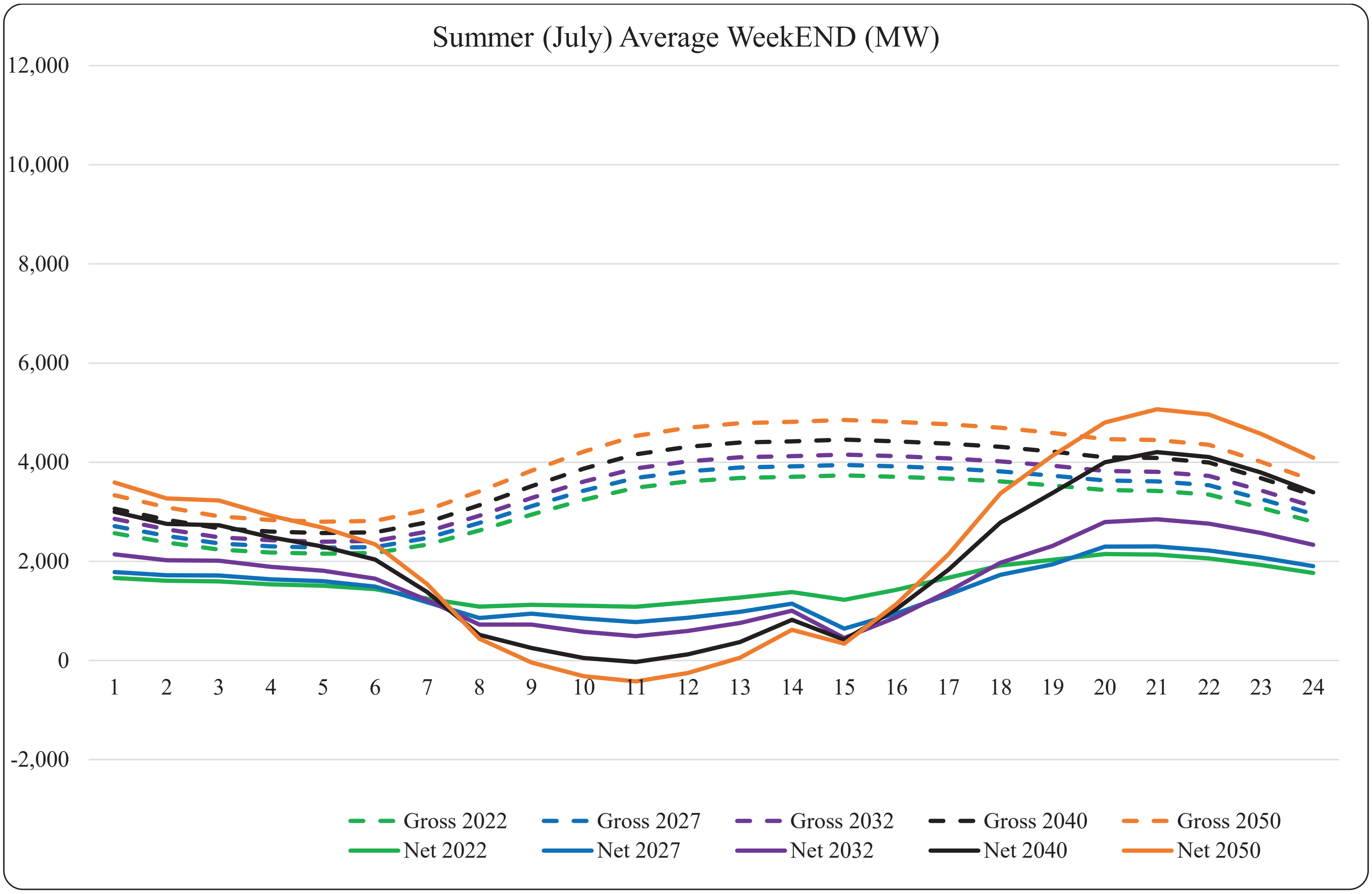

Winter (January) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

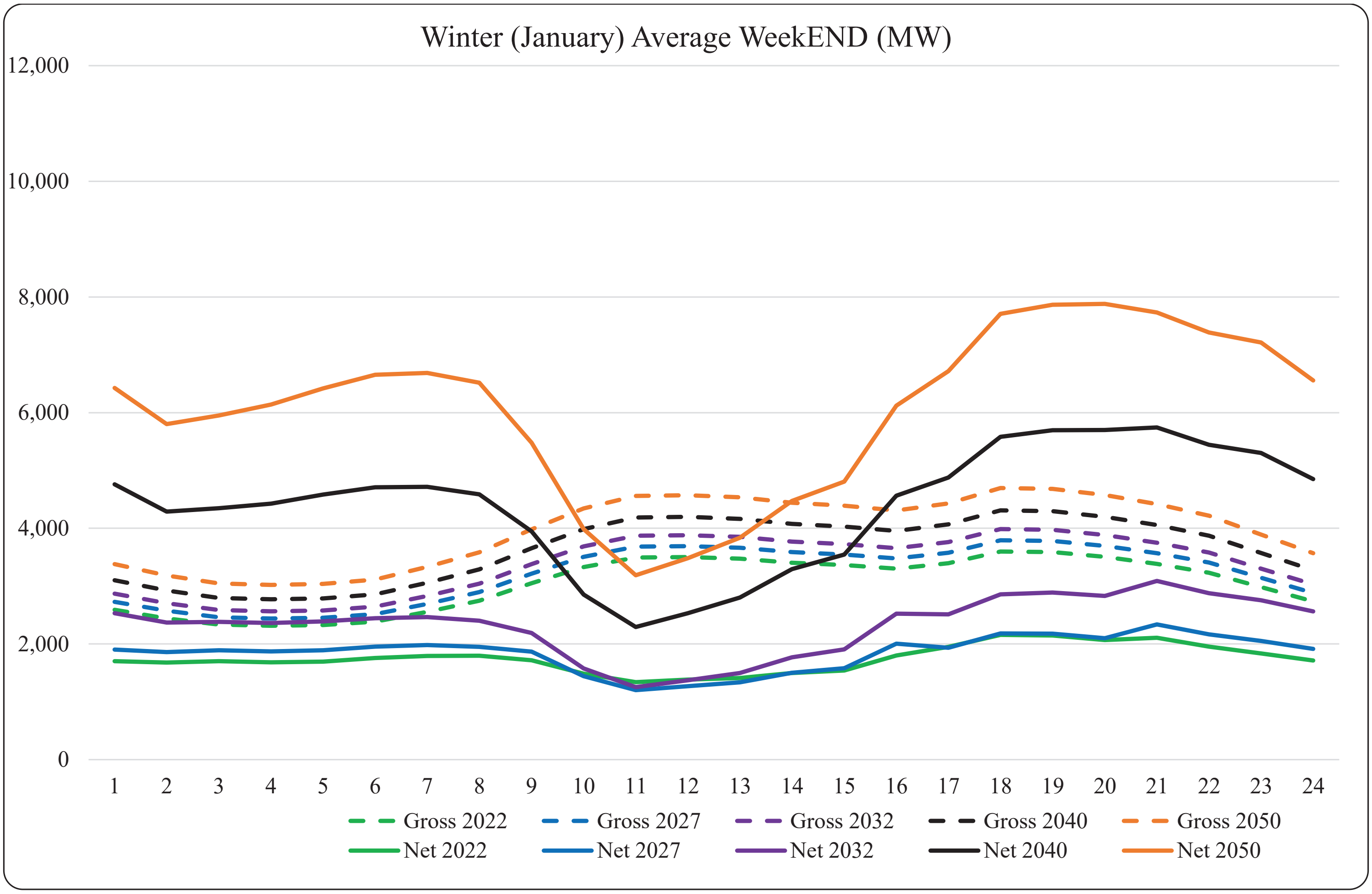


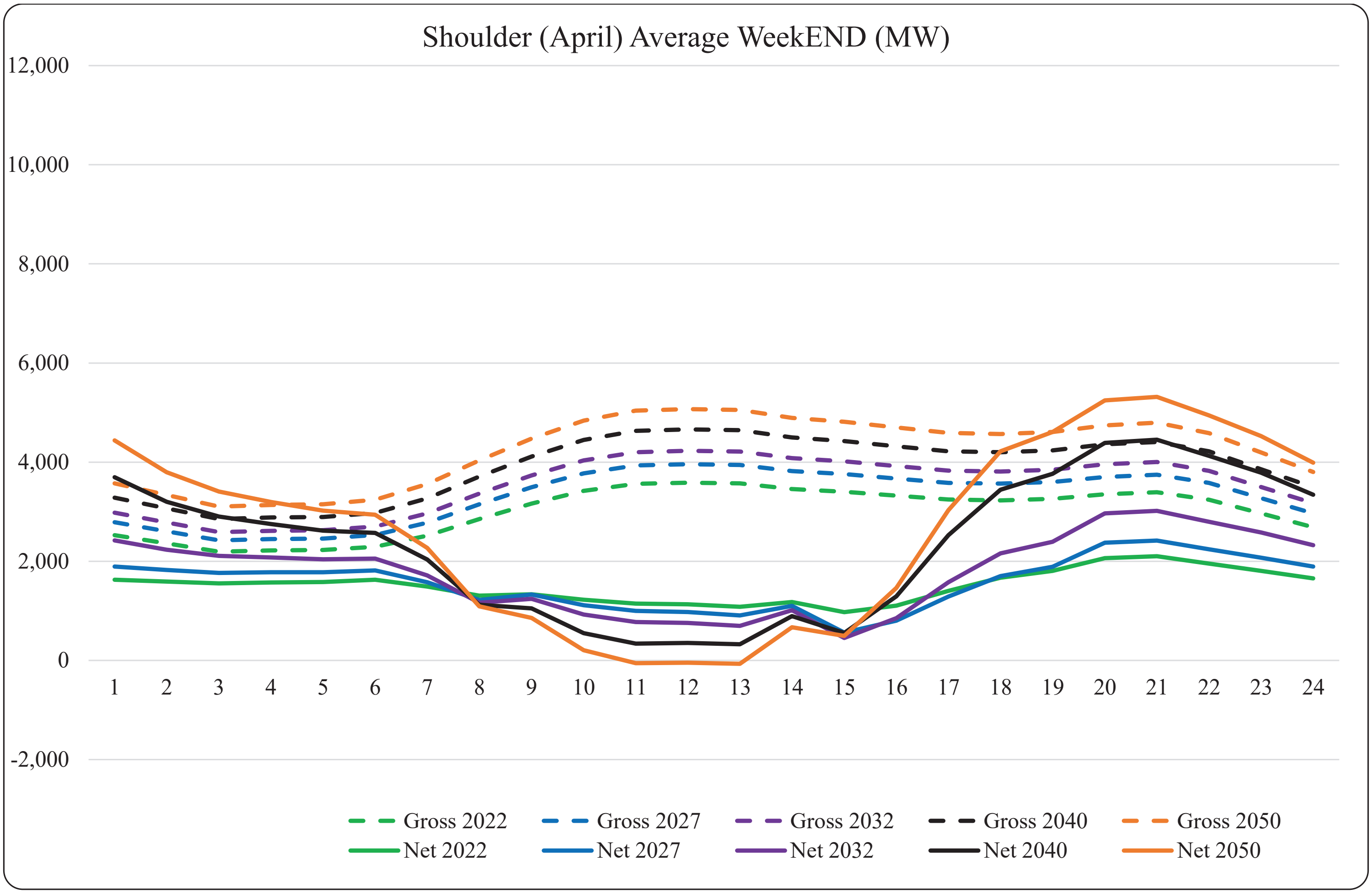
Shoulder (April) Average Weekday (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

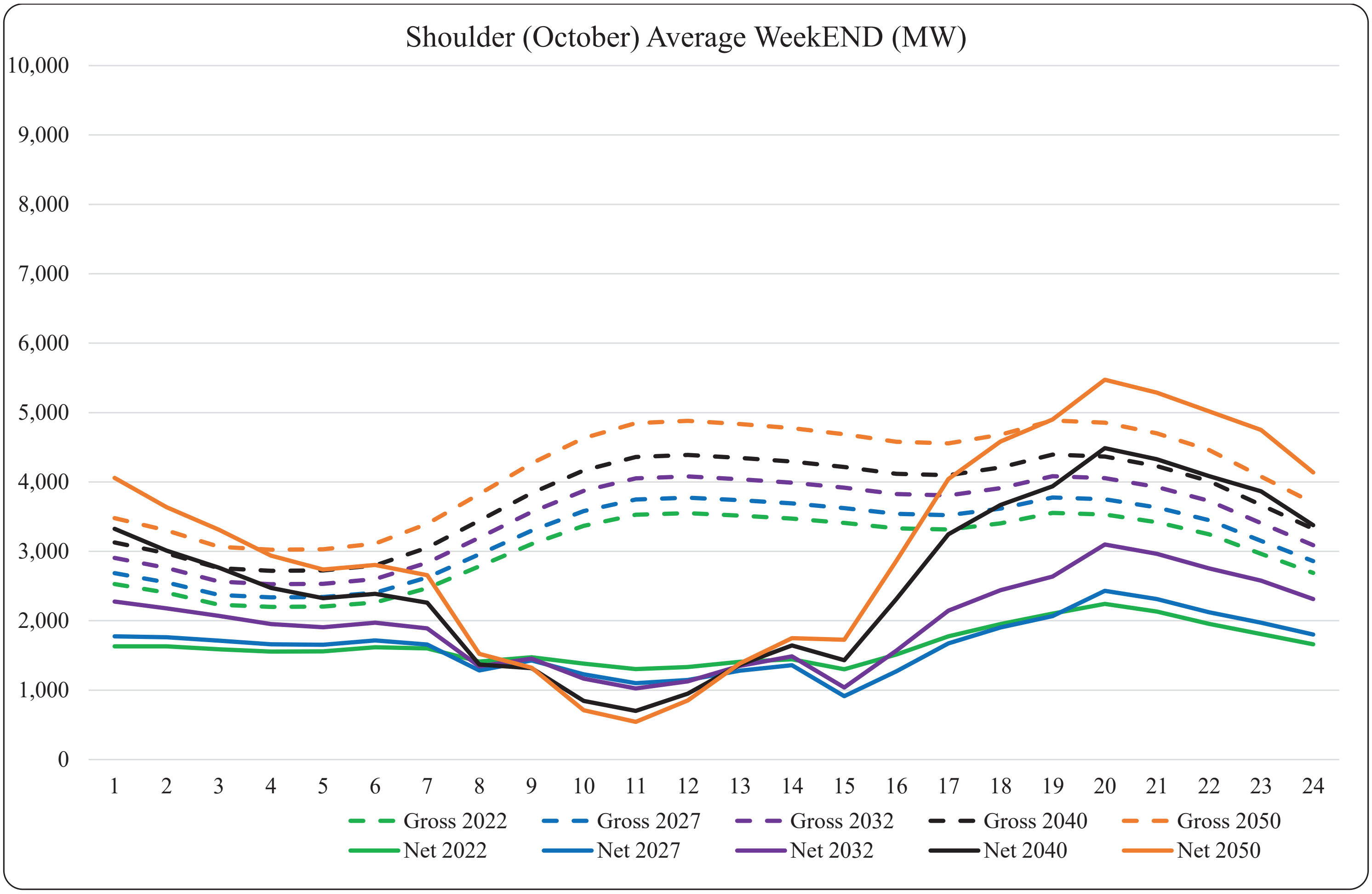


Shoulder (October) Average Weekday (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050


Summer (July) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050


Winter (January) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

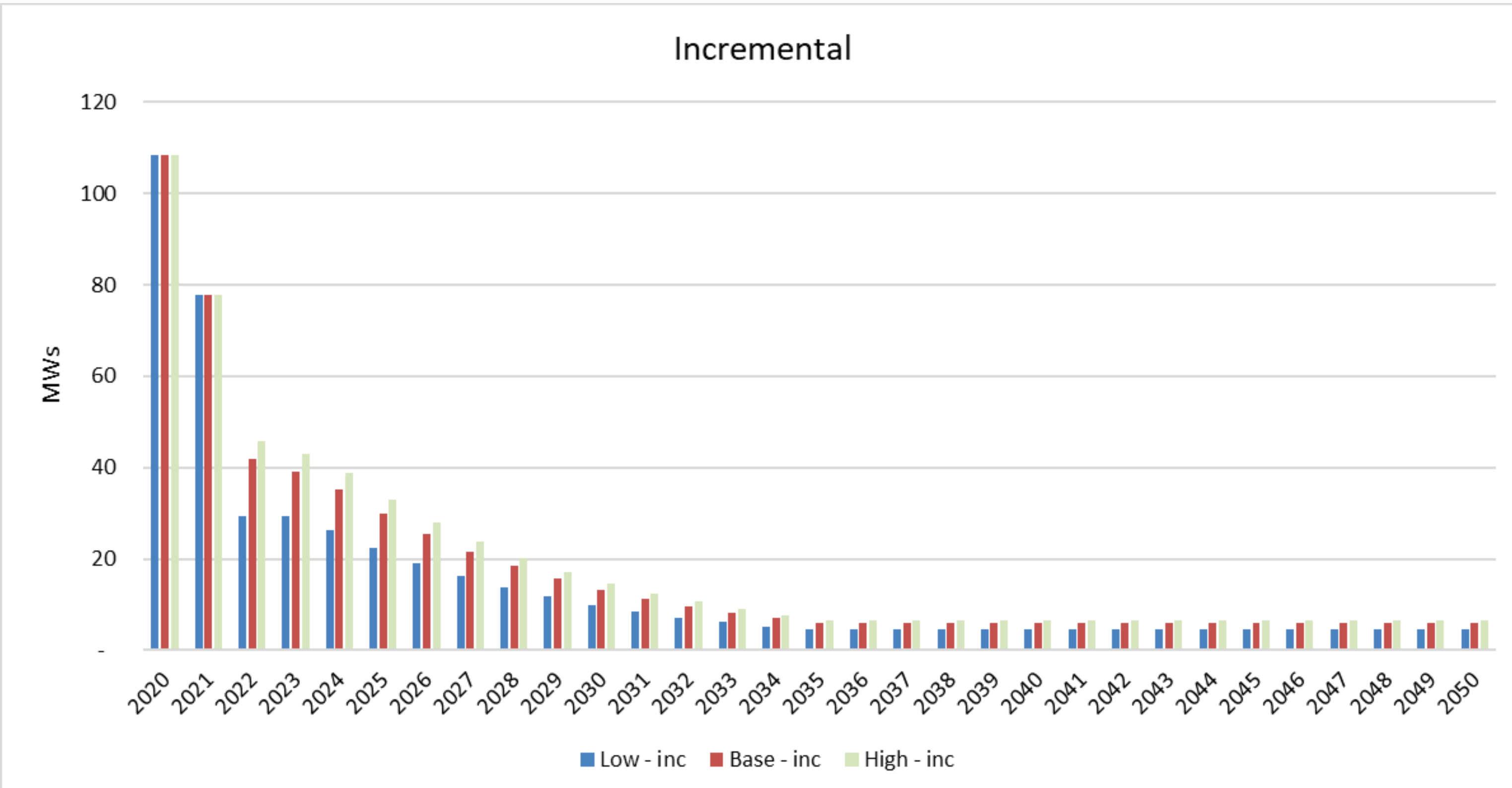

Shoulder (April) Average WeekEND (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050


Shoulder (October) Average WeekEND (MW)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2040
Gross 2050
Net 2022
Net 2027
Net 2032
Net 2040
Net 2050

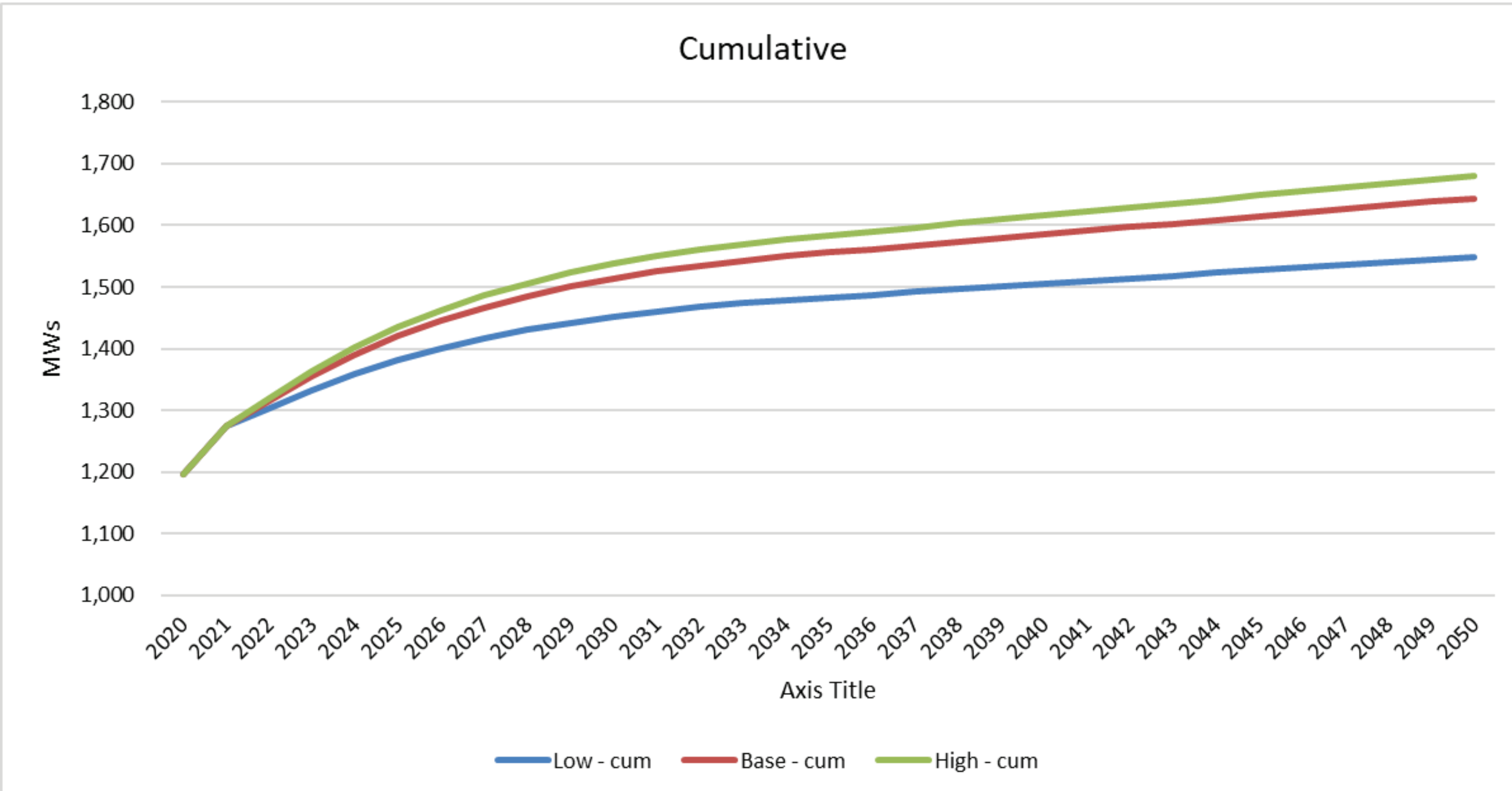
Appendix F: DER Scenarios Inputs

Energy Efficiency

Summer Peak MWs						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	108	1,196	108	1,196	108	1,196
2021	78	1,274	78	1,274	78	1,274
2022	29	1,303	42	1,316	46	1,320
2023	29	1,332	39	1,355	43	1,363
2024	26	1,359	35	1,390	39	1,401
2025	22	1,381	30	1,420	33	1,434
2026	19	1,400	25	1,445	28	1,462
2027	16	1,416	22	1,467	24	1,486
2028	14	1,430	18	1,485	20	1,506
2029	12	1,442	16	1,501	17	1,523
2030	10	1,452	13	1,514	15	1,538
2031	8	1,460	11	1,525	12	1,550
2032	7	1,468	10	1,535	11	1,561
2033	6	1,474	8	1,543	9	1,570
2034	5	1,479	7	1,550	8	1,577
2035	4	1,483	6	1,556	6	1,584
2036	4	1,488	6	1,562	6	1,590
2037	4	1,492	6	1,568	6	1,597
2038	4	1,496	6	1,573	6	1,603
2039	4	1,501	6	1,579	6	1,610
2040	4	1,505	6	1,585	6	1,616
2041	4	1,510	6	1,591	6	1,623
2042	4	1,514	6	1,597	6	1,629
2043	4	1,519	6	1,603	6	1,636
2044	4	1,523	6	1,609	6	1,642
2045	4	1,527	6	1,615	6	1,649
2046	4	1,532	6	1,620	6	1,655
2047	4	1,536	6	1,626	6	1,662
2048	4	1,541	6	1,632	6	1,668
2049	4	1,545	6	1,638	6	1,674
2050	4	1,549	6	1,644	6	1,681

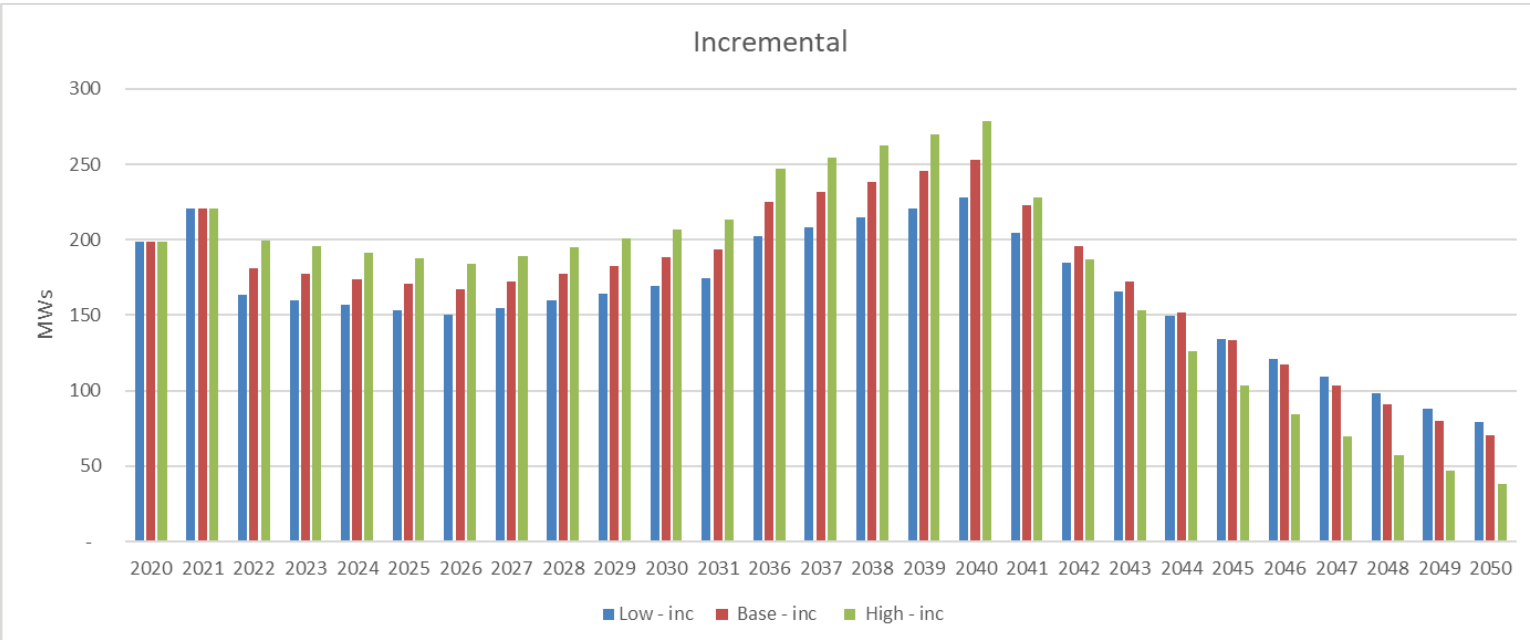


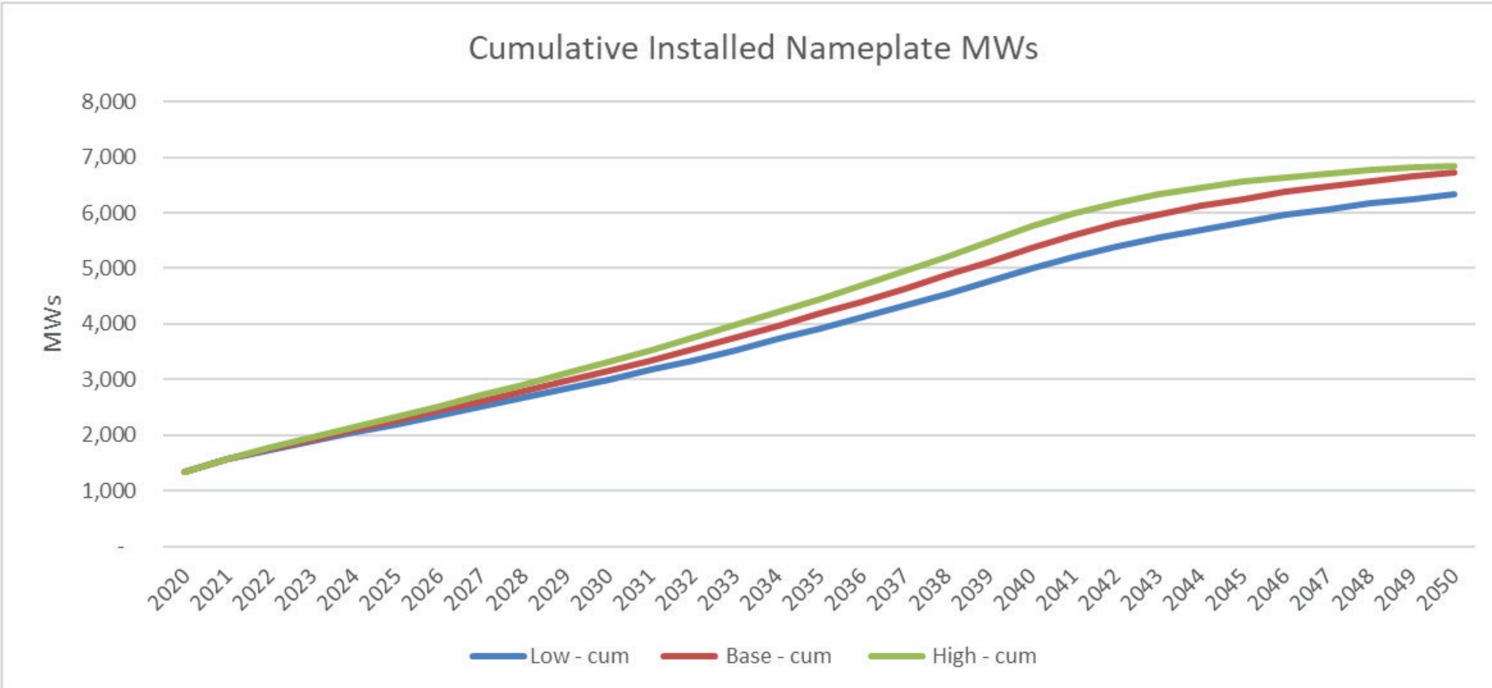
Incremental
MWs
120
100
80
60
40
20
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - inc
Base - inc
High - inc


Cumulative
MWs
1,800
1,700
1,600
1,500
1,400
1,300
1,200
1,100
1,000
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Axis Title
Low - cum
Base - cum
High - cum

Solar – PV

Connected Nameplated (MW)						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	198	1,343	198	1,343	198	1,343
2021	221	1,564	221	1,564	221	1,564
2022	163	1,727	181	1,745	199	1,763
2023	160	1,887	178	1,923	195	1,959
2024	157	2,044	174	2,097	192	2,150
2025	154	2,197	171	2,268	188	2,338
2026	150	2,348	167	2,435	184	2,522
2027	155	2,503	172	2,607	189	2,711
2028	160	2,662	177	2,785	195	2,907
2029	164	2,827	183	2,967	201	3,108
2030	169	2,996	188	3,155	207	3,315
2031	174	3,171	194	3,349	213	3,528
2032	180	3,350	200	3,549	220	3,747
2033	185	3,536	206	3,755	226	3,974
2034	191	3,726	212	3,966	233	4,207
2035	196	3,923	218	4,185	240	4,447
2036	202	4,125	225	4,409	247	4,694
2037	208	4,333	231	4,641	255	4,948
2038	215	4,548	238	4,879	262	5,211
2039	221	4,769	246	5,125	270	5,481
2040	228	4,996	253	5,378	278	5,759
2041	205	5,201	223	5,600	228	5,987
2042	184	5,386	196	5,796	187	6,174
2043	166	5,552	172	5,969	153	6,328
2044	149	5,701	152	6,120	126	6,453
2045	134	5,835	133	6,254	103	6,557
2046	121	5,956	117	6,371	85	6,641
2047	109	6,065	103	6,474	69	6,711
2048	98	6,163	91	6,565	57	6,767
2049	88	6,251	80	6,645	47	6,814
2050	79	6,331	70	6,716	38	6,852


Incremental
300
250
200
150
100
50
-
MWs
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Low - inc
Base - inc
High - inc

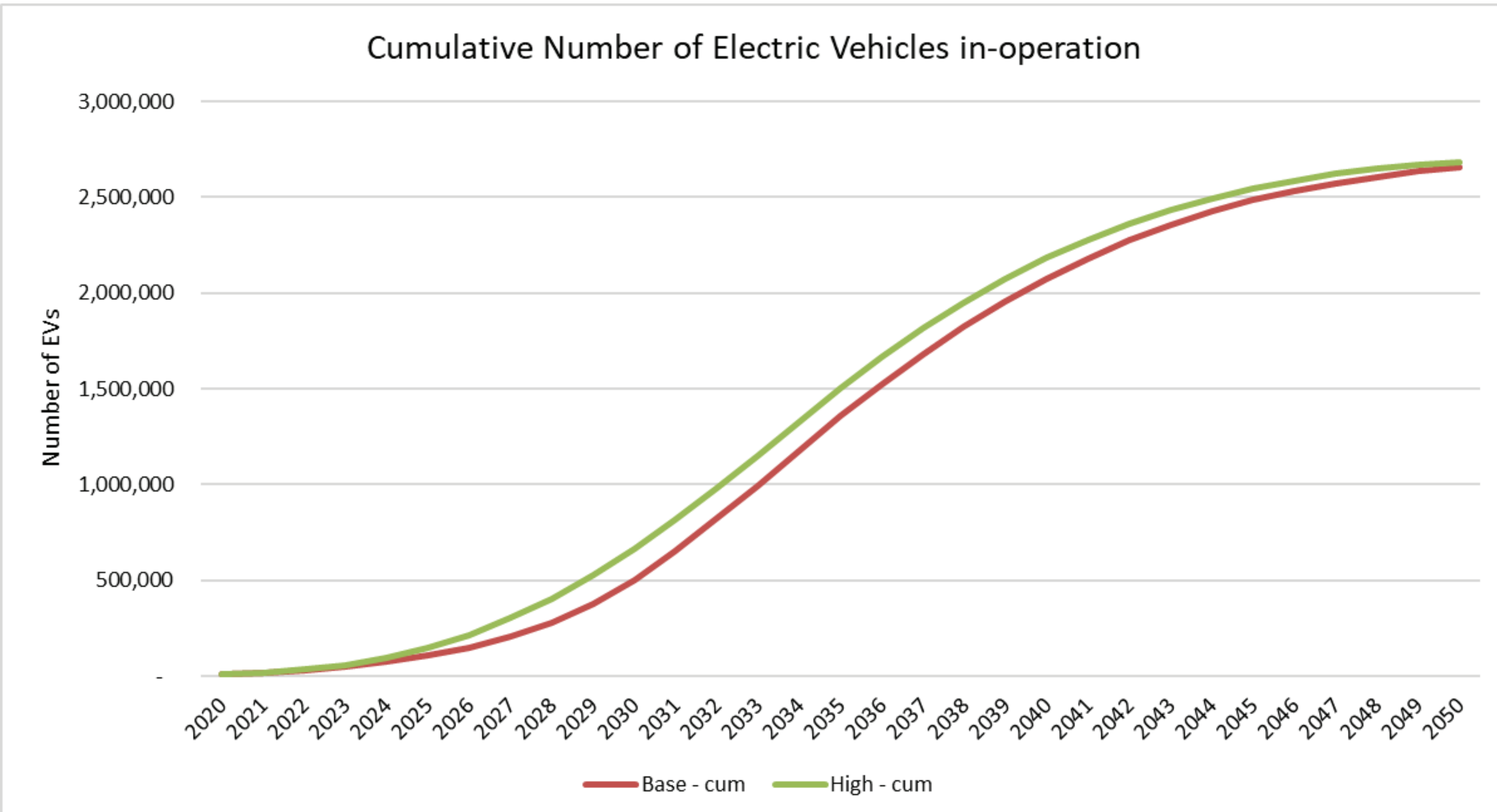


Cumulative Installed Nameplate MWs
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
MWs
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Low - cum
Base - cum
High - cum

Electric Vehicles

Number of Vehicles				
Year	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	2,847	13,919	2,847	13,919
2021	6,142	20,061	6,142	20,061
2022	12,167	32,228	14,070	34,131
2023	18,114	50,342	23,526	57,657
2024	24,477	74,819	36,733	94,390
2025	31,825	106,644	50,992	145,382
2026	42,982	149,626	70,386	215,768
2027	56,567	206,193	87,180	302,948
2028	72,673	278,866	103,774	406,722
2029	99,610	378,476	120,208	526,930
2030	122,001	500,477	138,469	665,399
2031	154,503	654,980	152,589	817,988
2032	164,701	819,681	162,128	980,116
2033	174,313	993,994	170,987	1,151,103
2034	181,691	1,175,685	177,535	1,328,638
2035	180,911	1,356,596	175,869	1,504,507
2036	168,802	1,525,398	162,786	1,667,293
2037	156,537	1,681,935	149,366	1,816,659
2038	142,846	1,824,781	134,543	1,951,202
2039	129,592	1,954,373	120,300	2,071,502
2040	120,268	2,074,641	110,266	2,181,768
2041	105,159	2,179,800	94,944	2,276,712
2042	93,758	2,273,558	83,547	2,360,259
2043	81,759	2,355,317	72,299	2,432,558
2044	70,212	2,425,529	61,593	2,494,151
2045	59,261	2,484,790	51,486	2,545,637
2046	49,290	2,534,080	41,567	2,587,204
2047	40,301	2,574,381	33,298	2,620,502
2048	32,761	2,607,142	26,407	2,646,909
2049	26,486	2,633,628	20,769	2,667,678
2050	21,402	2,655,030	16,259	2,683,937

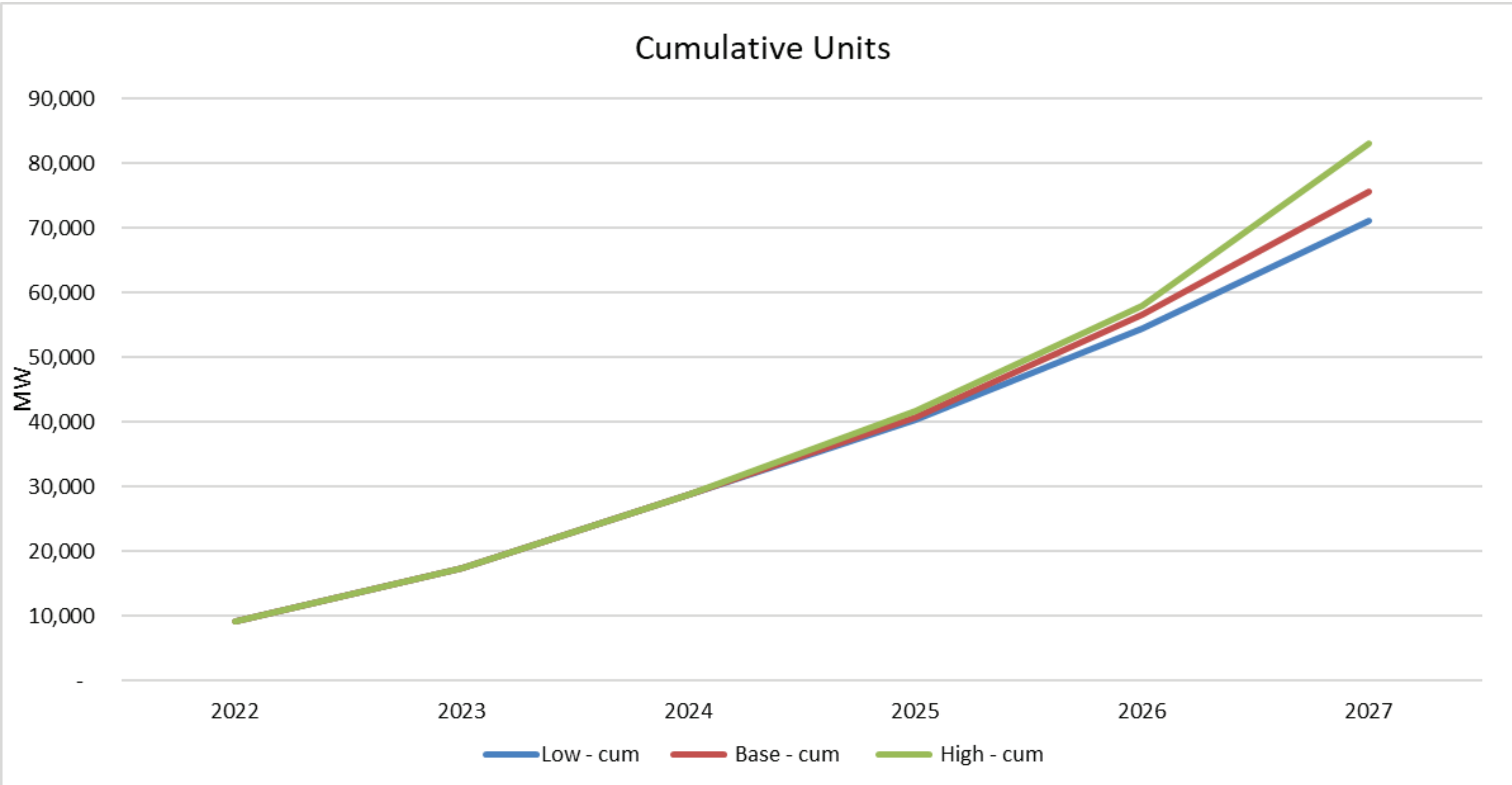
Number of Light-duty Vehicles				
Year	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	2,840	13,912	2,840	13,912
2021	6,140	20,052	6,140	20,052
2022	12,165	32,217	14,068	34,120
2023	17,802	50,019	23,222	57,342
2024	24,060	74,079	36,308	93,650
2025	31,300	105,379	50,448	144,098
2026	42,353	147,732	69,717	213,815
2027	55,747	203,479	86,294	300,109
2028	71,427	274,906	102,402	402,511
2029	97,856	372,762	118,219	520,730
2030	119,746	492,508	135,841	656,571
2031	151,757	644,265	149,301	805,872
2032	161,624	805,889	158,343	964,215
2033	170,919	976,808	166,702	1,130,917
2034	178,068	1,154,876	172,837	1,303,754
2035	177,093	1,331,969	170,779	1,474,533
2036	164,815	1,496,784	157,338	1,631,871
2037	152,557	1,649,341	143,878	1,775,749
2038	138,905	1,788,246	129,048	1,904,797
2039	125,713	1,913,959	114,860	2,019,657
2040	116,478	2,030,437	104,919	2,124,576
2041	101,479	2,131,916	89,850	2,214,426
2042	90,134	2,222,050	78,793	2,293,219
2043	78,214	2,300,264	67,911	2,361,130
2044	66,764	2,367,028	57,592	2,418,722
2045	55,930	2,422,958	47,888	2,466,610
2046	46,092	2,469,050	39,107	2,505,717
2047	37,251	2,506,301	31,254	2,536,971
2048	29,852	2,536,153	24,708	2,561,679
2049	23,784	2,559,937	19,412	2,581,091
2050	18,910	2,578,847	15,233	2,596,324

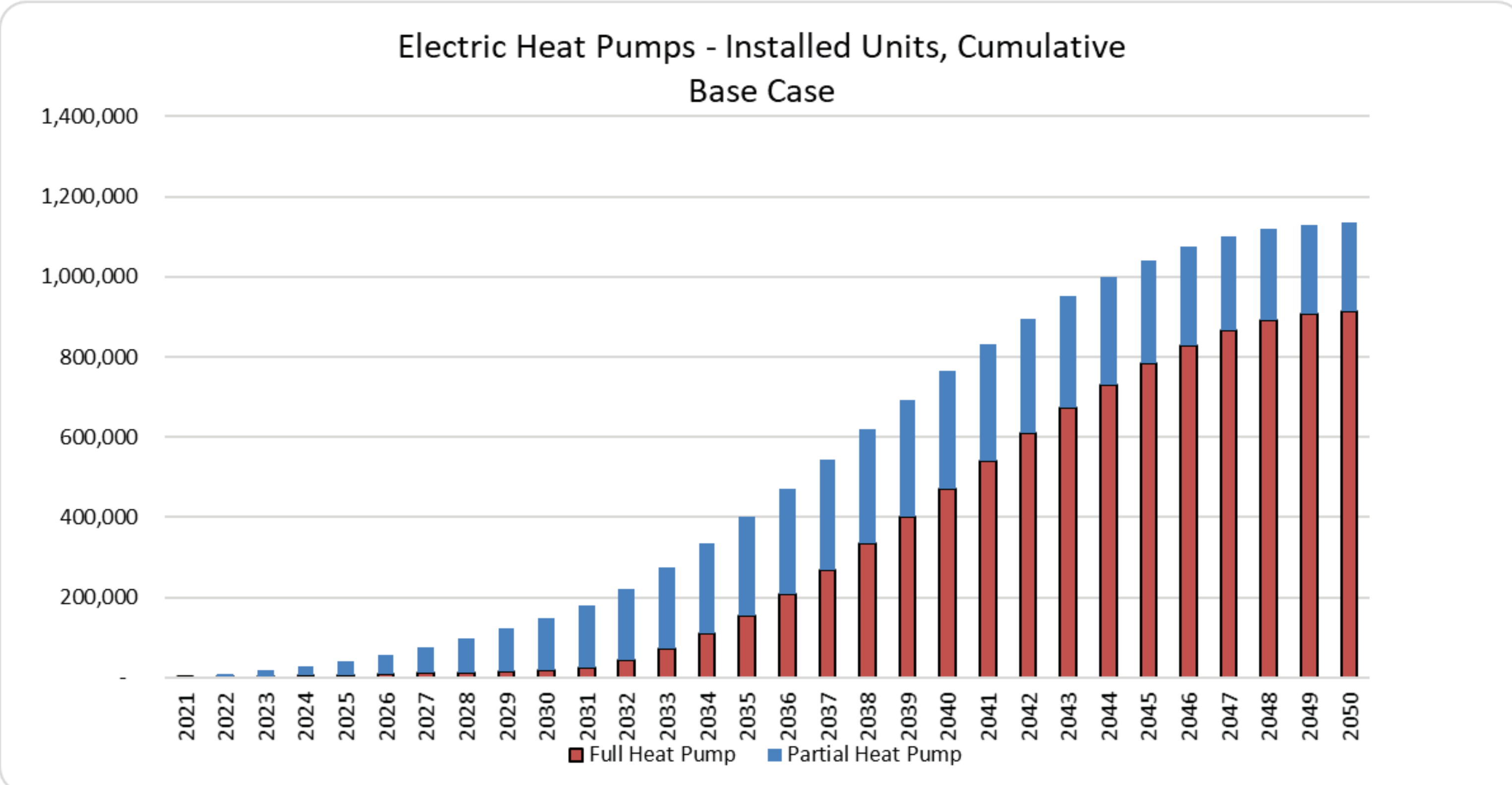

Cumulative Number of Electric Vehicles in-operation
Number of EVs
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050
Base - cum
High - cum

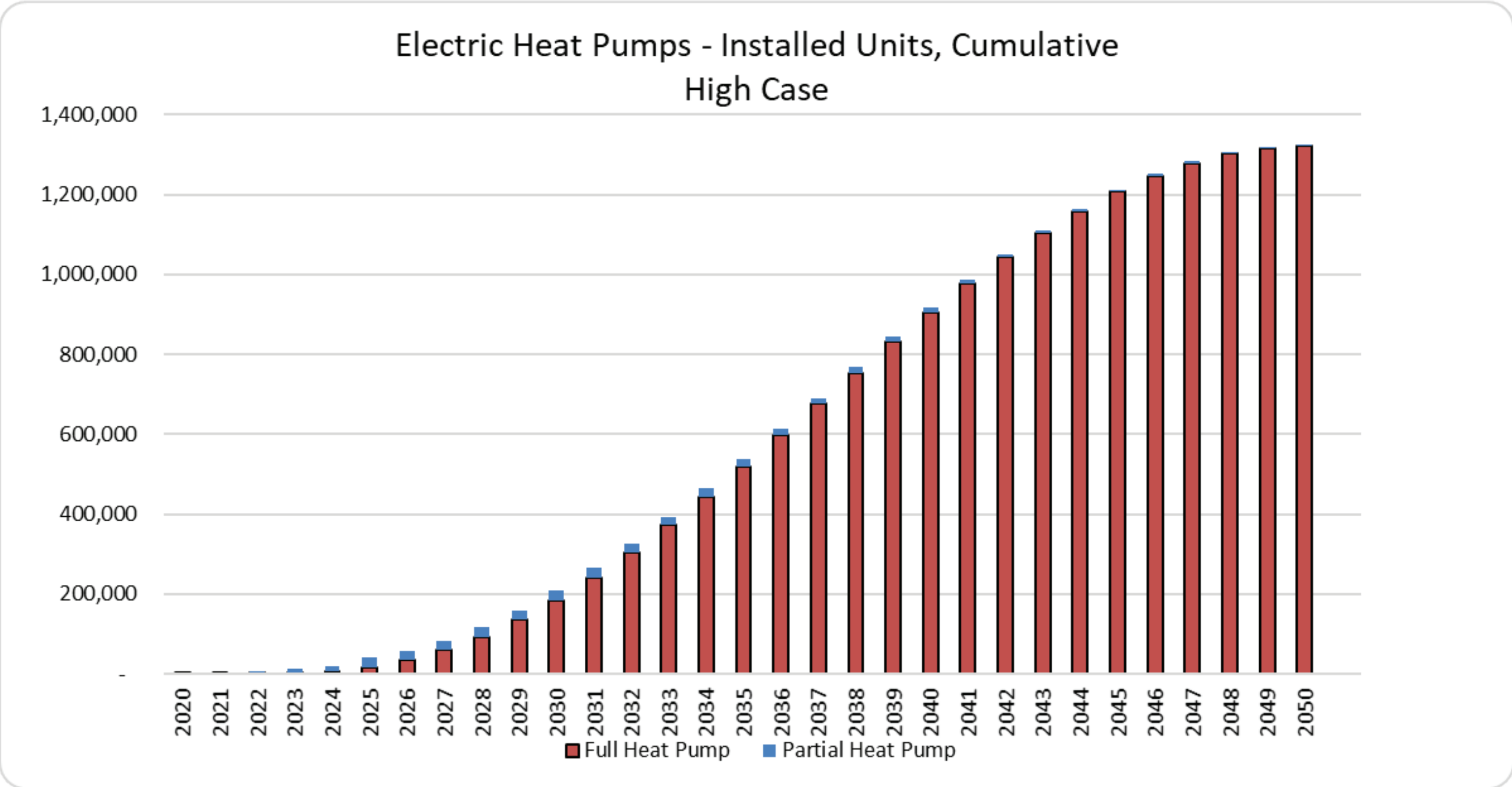
Electric Heat Pumps

(Number of Electric Heat Pumps)

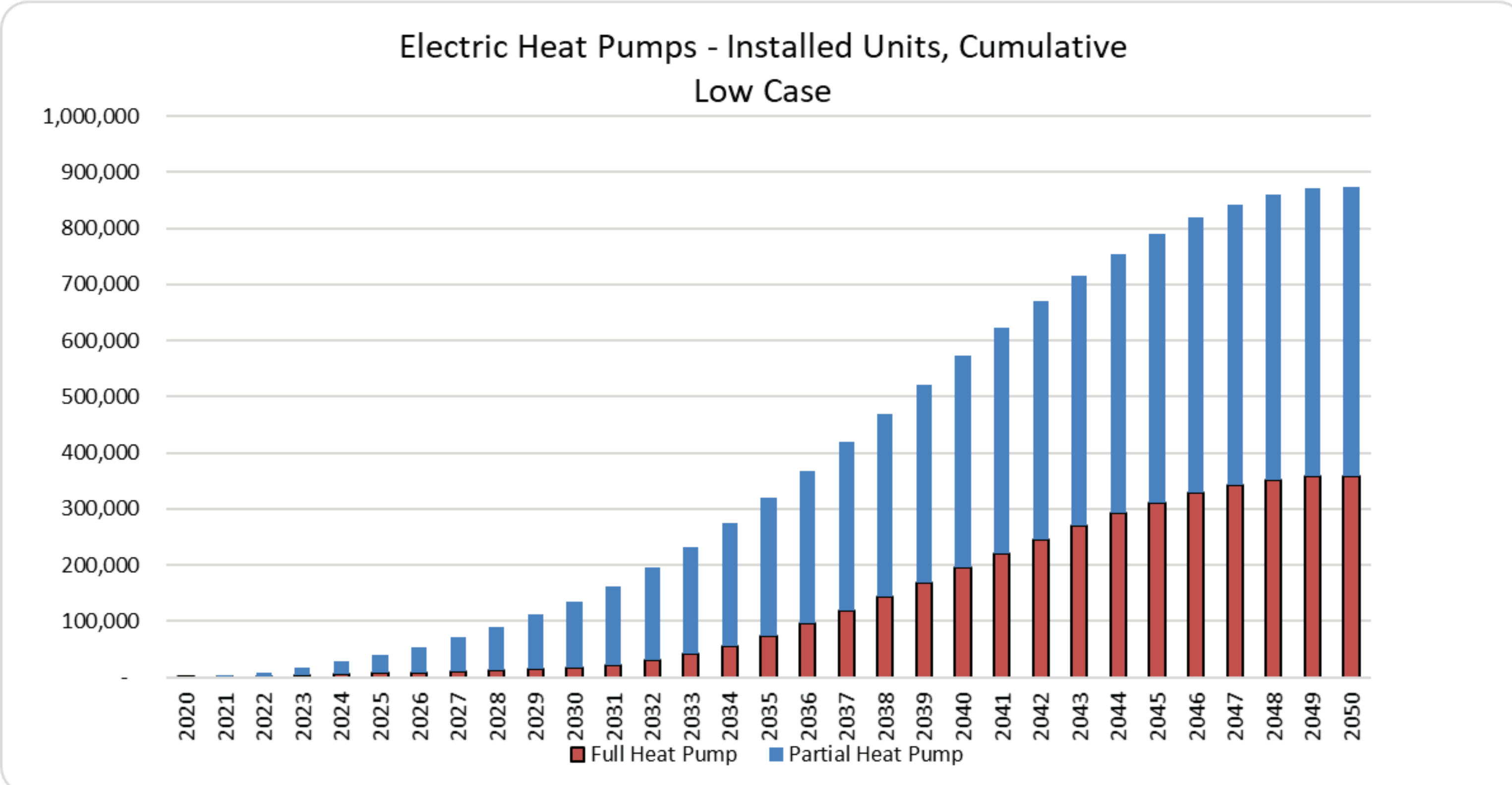
Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2019	849	849	849	849	849	849
2020	1,515	2,364	1,515	2,364	1,515	2,364
2021	1,957	4,321	1,957	4,321	1,957	4,321
2022	4,782	9,102	4,782	9,103	4,782	9,103
2023	8,238	17,341	8,238	17,341	8,238	17,341
2024	11,452	28,792	11,452	28,792	11,452	28,792
2025	11,427	40,219	11,992	40,785	12,886	41,678
2026	14,184	54,403	15,748	56,533	16,272	57,950
2027	16,800	71,203	19,084	75,617	25,132	83,082
2028	19,243	90,446	21,897	97,514	33,633	116,715
2029	21,482	111,928	24,099	121,613	41,654	158,369
2030	23,491	135,420	25,618	147,231	49,081	207,450
2031	27,240	162,660	31,821	179,052	55,807	263,257
2032	32,611	195,271	42,482	221,534	61,736	324,993
2033	37,501	232,773	51,947	273,482	66,784	391,777
2034	41,809	274,581	59,993	333,475	70,879	462,655
2035	45,443	320,024	66,434	399,909	73,962	536,617
2036	48,324	368,349	71,130	471,039	75,989	612,606
2037	50,388	418,737	73,985	545,024	76,932	689,538
2038	51,585	470,321	74,954	619,978	76,777	766,315
2039	51,881	522,202	74,065	694,043	75,526	841,841
2040	51,261	573,464	71,371	765,414	73,197	915,038
2041	49,728	623,192	67,335	832,748	69,824	984,862
2042	47,301	670,493	62,198	894,946	65,454	1,050,316
2043	44,018	714,511	55,937	950,883	60,150	1,110,466
2044	39,935	754,446	48,906	999,789	53,988	1,164,454
2045	35,122	789,567	41,424	1,041,213	47,055	1,211,509
2046	29,664	819,231	33,748	1,074,961	39,451	1,250,960
2047	23,660	842,891	26,063	1,101,024	31,283	1,282,243
2048	17,219	860,110	18,474	1,119,499	22,670	1,304,913
2049	10,461	870,571	11,015	1,130,513	13,733	1,318,645
2050	3,509	874,080	3,659	1,134,172	4,599	1,323,245


Cumulative Units
MW
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2022
2023
2024
2025
2026
2027
Low - cum
Base - cum
High - cum


Electric Heat Pumps - Installed Units, Cumulative
Base Case
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump

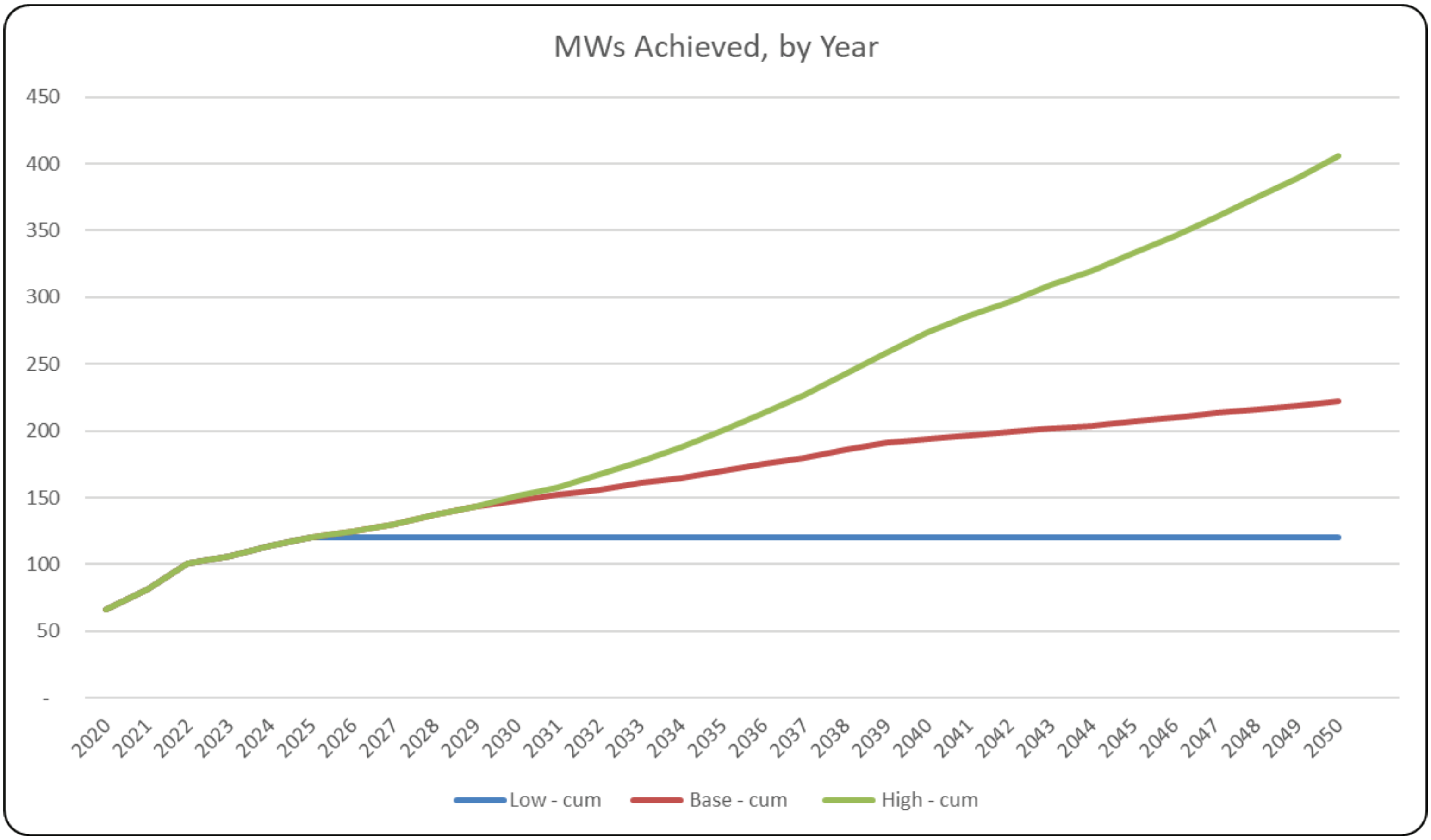


Electric Heat Pumps - Installed Units, Cumulative
High Case
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump


Electric Heat Pumps - Installed Units, Cumulative
Low Case
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Full Heat Pump
Partial Heat Pump

Demand Response

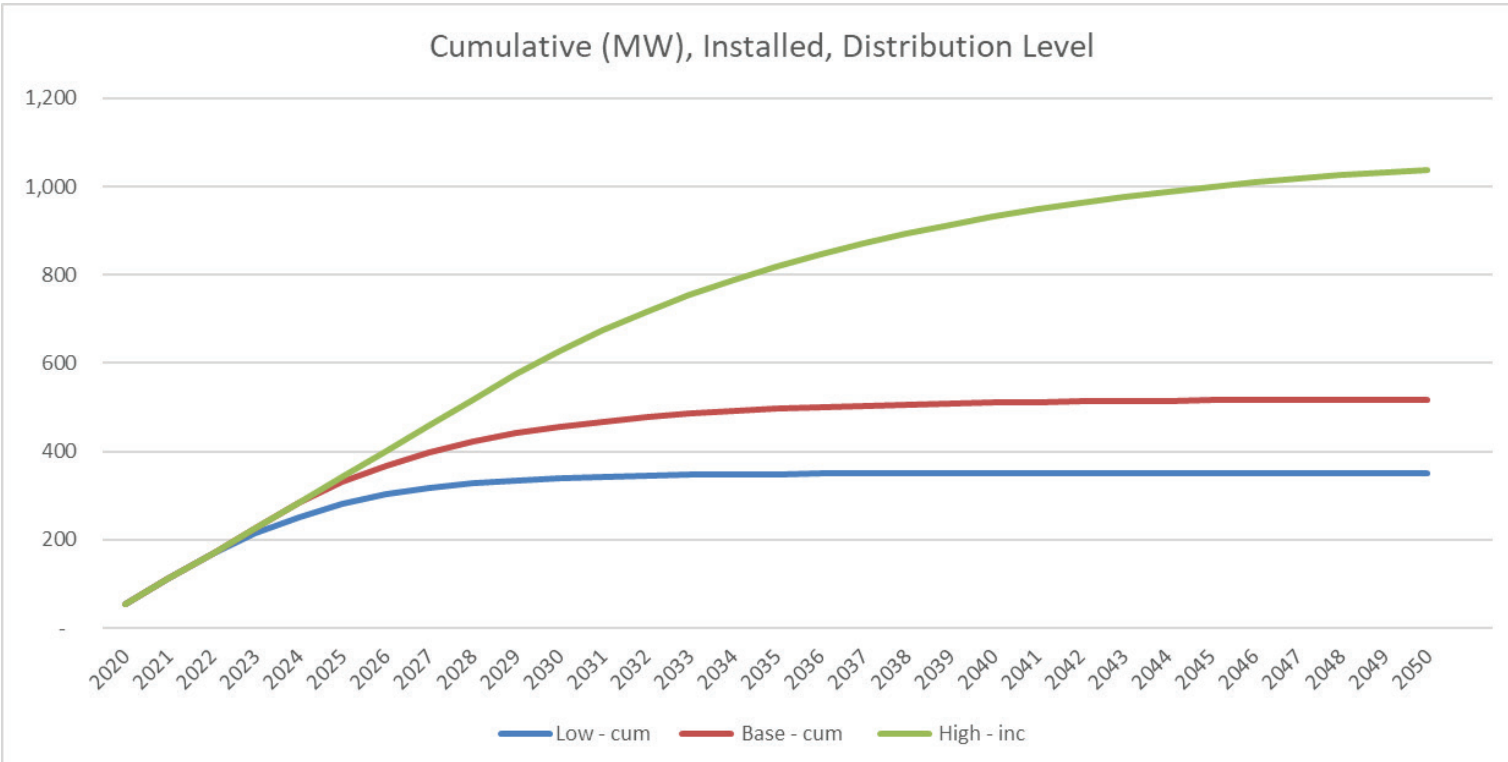
year	Low - cum	Base - cum	High - cum
2020	66	66	66
2021	81	81	81
2022	101	101	101
2023	106	106	106
2024	114	114	114
2025	120	120	120
2026	120	125	125
2027	120	130	130
2028	120	137	137
2029	120	143	143
2030	120	148	151
2031	120	152	158
2032	120	156	167
2033	120	161	177
2034	120	165	188
2035	120	170	200
2036	120	175	213
2037	120	180	227
2038	120	186	243
2039	120	191	259
2040	120	194	274
2041	120	197	286
2042	120	199	297
2043	120	202	309
2044	120	204	320
2045	120	207	333
2046	120	210	346
2047	120	213	360
2048	120	216	375
2049	120	219	389
2050	120	222	406



MWs Achieved, by Year
450
400
350
300
250
200
150
100
50
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - cum
Base - cum
High - cum

Energy Storage

year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	30	53	30	53	30	53
2021	58	111	58	111	58	111
2022	58	169	58	169	58	169
2023	46	215	58	227	58	227
2024	37	252	58	285	58	285
2025	30	282	46	331	58	343
2026	21	303	37	368	58	401
2027	15	318	30	398	58	459
2028	10	328	24	422	58	517
2029	7	335	19	441	58	575
2030	5	340	15	456	52	627
2031	3	343	12	468	47	674
2032	2	345	10	478	42	716
2033	2	347	8	486	38	754
2034	1	348	6	492	34	788
2035	1	349	5	497	31	819
2036	1	350	4	501	28	847
2037	-	350	3	504	25	872
2038	-	350	3	507	22	894
2039	-	350	2	509	20	914
2040	-	350	2	511	18	932
2041	-	350	1	512	16	948
2042	-	350	1	513	15	963
2043	-	350	1	514	13	976
2044	-	350	1	515	12	988
2045	-	350	1	516	11	999
2046	-	350	-	516	10	1,009
2047	-	350	-	516	9	1,018
2048	-	350	-	516	8	1,026
2049	-	350	-	516	7	1,033
2050	-	350	-	516	6	1,039


Cumulative (MW), Installed, Distribution Level
1,200
1,000
800
600
400
200
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Low - cum
Base - cum
High - inc

Appendix G: DER Scenarios Development

Energy Efficiency

Persistent and non-persistent savings are differentiated to correctly account for the accumulation of claimable savings over time. Non-persistent savings from behavioral programs like the home energy report do not accumulate over time. Home energy report savings are assumed to remain at the same level for each year of the planning cycle across all three cases. Savings from persistent programs do accumulate over time (i.e. lighting programs).

All EE savings are in adjusted gross terms.

Any savings from heat pumps and demand response programs are removed as they are projected separately.

Base

- The Company annual plans from the Subject Matter Experts (SMEs) are used for the short-term through 2024.
- Post-2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year. The residential savings growth rate slows by 15% annually to account for saturation of claimable savings until 2035 and stays flat thereafter until 2050 whereas the commercial savings growth rate slows by 5% annually until 2050.

High

- For 2021, the incremental EE is equal to the base case and reflects the Company's annual plan.
- Post 2021, a declining annual incremental EE assumption is applied to the 2021 incremental commercial savings. The rate is at 5% to model a slower decline in claimable persistent savings. For residential savings, the incremental is 110% of the base case incremental savings value.

Low

- For 2021, the incremental EE is equal to the base case and reflects the Company's annual plan.
- Post-2021, incremental savings for residential and commercial from traditional EE programs are 75% of base case. This is the result of both rising EE baselines leading to lower levels of claimable savings and the shifting of resources to electrification of heat programs.

Solar -PV

Base

- The near-term prediction is based on the recent historical trend and SME's outlook on applications in the Company's queue and the assumption that National Grid will fill its share (i.e., 45%23) of the State's existing solar standards of 3.2 GW24 by mid 2020s.
- In the longer-term, continuous growth is projected in order to achieve the National Grid's share (i.e., 45%) of the State policy target under the All Options scenario as stated in its 2050 decarbonization roadmap25. The All Options scenario targets a 6.99 GW of behind-the-meter (BTM) PV connection and a 16.2 GW of ground-mounted PV connection by 2050 for the State of Massachusetts. In this base case, it is assumed that all the BTM PV and 50% of the ground-mounted PV will be on the distribution system. It is then assumed that the Company will take its share of these. Thus, about 3.1 GW (6.9 GW * 100% * 45%) of BTM PV and 3.6 GW (16.2 GW * 50% * 45%) of ground-mounted PV are projected to be on the Company's distribution system by 2050.

High

- The near-term predictions are based on the SME's outlook for a stretching target and the assumption that the Company will achieve its estimated share of the State's existing solar standards at an earlier year than in the base case.
- In the longer term, the high case assumes the Company achieves its estimated share of the policy target of the All-Option scenario at a slightly early year.

Low

- The near-term predictions are based on the SME's outlook for a moderate connection case and the assumption that the Company will achieve its estimated share of the State's existing solar standards at a slightly later year than in the base case.
- In the longer term, the low case estimates the Company may achieve its estimated share of the policy target of the All-Option scenario at a slightly later year.

[23] 45% was the share for National Grid when the SMART program opened. It was the percentage of customers National Grid serves in the State of Massachusetts compared with Eversource and Unitil. This same share is assumed for calculating National Grid share of the State's existing and planned solar goals.
[24] *MA Clean Energy and Climate Plan for 2030*, page 68, June 2022.
[25] *Massachusetts 2050 Decarbonization Roadmap*, December 2020

Electric Vehicles

Light-duty Vehicles

Base

The base case is developed around California's Advanced Clean Car II (ACC-II)26 rules, which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of light-duty vehicle (LDV) sales is created based on the techno-economic potential and current market trends. In the medium-term (2026 -2030), the ACC-II rules have a range of possible outcomes, so the zero-emission vehicle sales share rises in line with the "flexibilities"27 (or lower-bound) of what the ACC-II rules require, reaching 59.5% in 2030. In the longer term (2031 and onward), zero emission vehicle sales match the ACC-II rules and reach 100% zero emissions vehicles in 2035 (and assume no more than 20% plug-in hybrid electric vehicles). Vehicle scrap is assumed based upon market data to develop the net EV in-operation numbers.

High

The high case is developed based upon the upper-bound of ACC-II rules for both near and long terms in which the zero-emission vehicle share of LDV sales is estimated to achieve 68% by 2030 and 100% by 2035.

Low

The low case is the same as the base case in terms of zero-emission vehicle sales share and growth rate, following the lower-bound of ACC-II rules in the near term, and trending to the upper-bound of ACC-II rules in 2026 and onward. It differs, however, from the base case in the EV charging profiles. While unmanaged charging is considered for the base case, the managed charging profile to mitigate the EV load impact on the peak demand is considered in the low case. For managed charging, it is assumed that 75% of the light-duty EV (LDEV) owners have access to the home chargers, and 75% of those do not charge their vehicles at home during the peak hours (4PM to 10PM). Away-from-home charging is assumed to continue unmanaged.

Medium-duty and Heavy-duty Vehicles, and E-buses

Base

The base case for the adoptions of medium-duty EV (MDEV), heavy- duty EV (HDEV) and E-buses is based on the California's Advanced Clean Trucks (ACT)28 rules through 2035 which have been adopted by the state. In the base case, the sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035. To extend the forecast until 2050, a similar growth rate is considered from 2036 to 2040, and after that 3% growth

[26] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii, retrieved September 2022

[27] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

[28] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks, retrieved September 2022

in sales share is assumed through 2050. That leads to 100%, 80%, and 100% sales shares for MDEV, HDEV, and E-Buses by the end of the forecast horizon, respectively.

High

The high case reflects an accelerated adoption rate. It is built on the base case where each year is multiplied by a growth factor. The growth factor is created to show 2% more increase in the sales share than the previous year until 2027. It will then increase to 3% through the end of the forecast horizon. That results in 85%, 54% and 100% sales shares for MDEV, HDEV, and E-Buses, respectively, by the end of 2035. All three sales shares reach to 100% by 2050.

Low

The low case is intended to show a slower growth rate than the base case. It is created based upon Bloomberg New Energy Finance's (BNEF) 2022 Electric Vehicle Outlook, which projects the MDEV, HDEV, and E-Buses in-operation shares through 2040. To extend the forecast until 2050, the Company extended the trend in the growth of EV sales for each vehicle type. The estimated vehicle-in-operation (VIO) shares for MDEV, HDEV, and E-Buses are about 14%, 18% and 63% by the end of 2035, respectively. The shares will increase to 51%, 63%, and 100% for MDEV. HDEV, and E-Buses by the end of the forecast horizon, respectively.

Combined forecasts

The overall base EV case is created by combining the base cases for LDEV, MDEV, HDEV, and E-buses. The overall high EV case combines the high case for LDEV, MDEV and HDEV and high E-bus case. The overall low EV case combines the low cases for LDEV, MDEV, HDEV, and E-buses.

Electric Heat

The three scenarios assume that the Company will meet the approved heat pump targets for the years 2022 to 2024.

Base Case:

Post 2024, the company assumes that Company's pro rata share of CECP PHASED pathway's target in 2050 will be met[29]. Thus, about 1.34 million of units will be installed by 2050 and about 80% of those will be installed as full applications. Penetration rates are expected to be about 86% of residential homes and 58% of commercial space heating capacity.

High Case:

Post 2024, the company assumes that Company's pro rata share of CECP Full Electrification pathway's target in 2050 will be met. In this case, the company would expect about 1.56 million full application heat pump installations by that year. This could represent the about 97% of penetration of all residential home and 88% of commercial space heating capacity in the commercial sector.

Low Case:

Post 2024, the company assumes that Company's pro rata share of CECP HYBRID pathway's target in 2050 will be met That would mean that about 1.03 mill. of heat pumps will be expected by 2050. The percentage of full applications in this scenario is lower than in other scenarios or 40% for the residential sector and 60% for the commercial sector.

[29] *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, June 2022

Demand Response

Base Case:

For the short term (i.e. until 2024), he forecast represents the projections developed by the Company's demand response SME. the approved Company targets from the SME Program Administrator for DR is used as the projection. Post year 2024, most technologies will growth annually at a decreasing rate. The annual average growth is approximately 2.5% over the forecast horizon[30].

High Case:

The high case is a continued incremental growth following the approved program years. Beginning in year 2025, most technologies will growth annually at a decreasing rate. The annual average growth is approximately 5.0% over the forecast horizon[33].

Low Case:

For the short-term, the approved Company targets from the SME Program Administrator for DR is used as the projections. Post year 2024, no additional incremental MW are added. It is assumed that the program's market potential is at its maximum and the projections are held constant through year 2050

[30] Exception: C&I Peak Savings is fixed for the entire forecast period at the 2022 level

Energy Storage

Base Case:

It was assumed that the Company would make a share of the statewide energy storage policy goals. In Massachusetts, the state policy is 1000 MWh by 2025[31]. For summer peak impacts this is first converted to a MW equivalent using a four to one charging to peak output factor. Thus, the 1000 MWh target is about 250 MW. Only a portion of these is at the distribution level and will lower the load forecast (the remainder being considered supply by the ISO-NE and not considered in this load forecast). Based on the amount of energy storage installed in the state as of 2021, about 36.5% is considered distribution level and thus load reducing.

Based on this the storage targets considered load reducing are lowered to 92.5 MWs (37% * 250) by year 2025. The Company's share of storage as in the state as of this year is about 78%. This is assumed to persist through year 2025. Thus, it is assumed that the year 2025 target for the Company is 72.15 MW (78% * 150). Not all energy storage will help to reduce the Company's summer peaks. A number of customers may use their storage to serve their own needs and times. It is assumed that only 85% of the installed energy storage amounts will impact the peak load. Thus, the final year 2025 target for peak reducing storage is 61.3 MW (85% * 72.15).

Current proposed forecast projects 282 MW (low case), 331 MW (base case) and 343 MW of energy storage by 2025 in the company' service territory. All projections are well above the inferred company's share in the state 2025 goal.

Massachusetts does not currently have explicit energy storage targets beyond year 2025. However, the state has published two studies, one the Clean Energy and Climate Plan for 2030 (CECP) and two the "Energy Pathways to Deep Decarbonization 2050". In the 2050 document, there are several scenarios that can guide the state to meeting its year 2050 long-term Climate goals. For example, by the year 2050, the "All options" scenario implies about 3,000 MW of large-scale energy storage (generation), "100% Renewable" scenario implies about 4,000 MW and the "No thermal" scenario implies 12,000 MW[32].

The company used those inferred long-run energy storage capacity to provide a context to its long-term forecast at the distribution level. In order to do that, the company made two assumptions in the long run: (a) the company 'share of energy storage in the state will approximate the company's load share in the state (45%) and (b) more energy storage will move towards the supply side and less new storage as distribution level load reductions. The longer-term distribution share is assumed to drop to 20% (vs. 37% now). By using these assumptions, the current company's long term energy storage installed capacity forecast in 2050 will relate to the different pathways from "Energy Pathways to Deep Decarbonization 2050 as follows: the low case forecast of 351 MW will be close to the "All Options" scenario, the base case forecast of 516 MW will be between "All Options" and "100% renewable" scenarios and finally, the high case forecast of 1,040 MW will be between "100% Renewables" and "No Thermal" scenarios, but closer to the later.

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[31] https://www.mass.gov/info-details/esi-goals-storage-target

[32] *Energy Pathways to Deep Decarbonization. A Technical Report of the Massachusetts 2050 Decarbonization RoadMap*. Page 61, December 2020

Finally, it is assumed the long-term peak reducing estimate will remain at 85% (85% is based on similar findings in New York which have significant pricing signals during peak hours). For the base case scenario, this lowers the final target to 439 MW by year 2050 (85% * 516).

The actual projections for installed energy storage are as follows. As of the end of year 2021 there was about 111 MW installed in the Company's service territory, about 58 MW of which was installed in the year 2021 alone. The base case assumes a continuation of this 58 MW per for the next three years, before assuming some saturation. Saturation is assumed to be 20% less per year for each subsequent year forward. This puts the Company on a path to easily surpass both the year 2025 and year 2050 targets determined above. Thus, it can be said that the Company is on-target for the CECP 2030 goals for this DER.

High Case:

The high case is similar to the base case, however, the 58 MW per year of new installations continues to year 2030. Then, saturation is assumed to be 10% less per year for each subsequent year forward up to 2050.

Low Case:

The low case assumes that saturation begins in 2023 already and at level of 20-30% less new installations each year. It is noted that this drop-off may not necessarily mean that total energy storage installations are dropping off, but instead that more have moved from the distribution level (which is the focus of this forecast) to the bulk system, supply side (which would not be included in this forecast).

Exhibit 8: ELF Report – Retail

MASSACHUSETTS ELECTRIC DISTRIBUTION

FY2024 to FY2028 Forecast

GWh Deliveries & Customer Counts

(Revenue & Rate Class)

[Massachusetts Electric Company]
[Nantucket Electric Company]

October 2022

Economics & Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	10/18/2022	- ORIGINAL
Rev1	10/28/2022	- updated EV profiles for medium- and heavy-duty vehicles and E-buses, which impacted the forecasts for the commercial and industrial sectors - updated EH counts being considered

General Notes:

- Historical data through August 2022; projections from September 2022 forward.
- Economic data is from Moody's vintage August 2022.
- Energy pricing, energy efficiency, electric heating, and solar data is internal data vintage August 2022.
- Electric Vehicle data is POLK data vintage December 2021.
- Source data for retail deliveries is the internal CSS billing system aggregate monthly reports.
- "Weather-Normal" is based on the ten-year average of monthly degree days from years 2012 to 2021.
- The modeling process employs a "reconstruction" for DERs in the historical input data set.

Report Contact(s):

Jingrui (Rain) Xie
jingrui.xie2@nationalgrid.com

Behnam Khaki
Behnam.Khaki@nationalgrid.com

TABLE OF CONTENTS

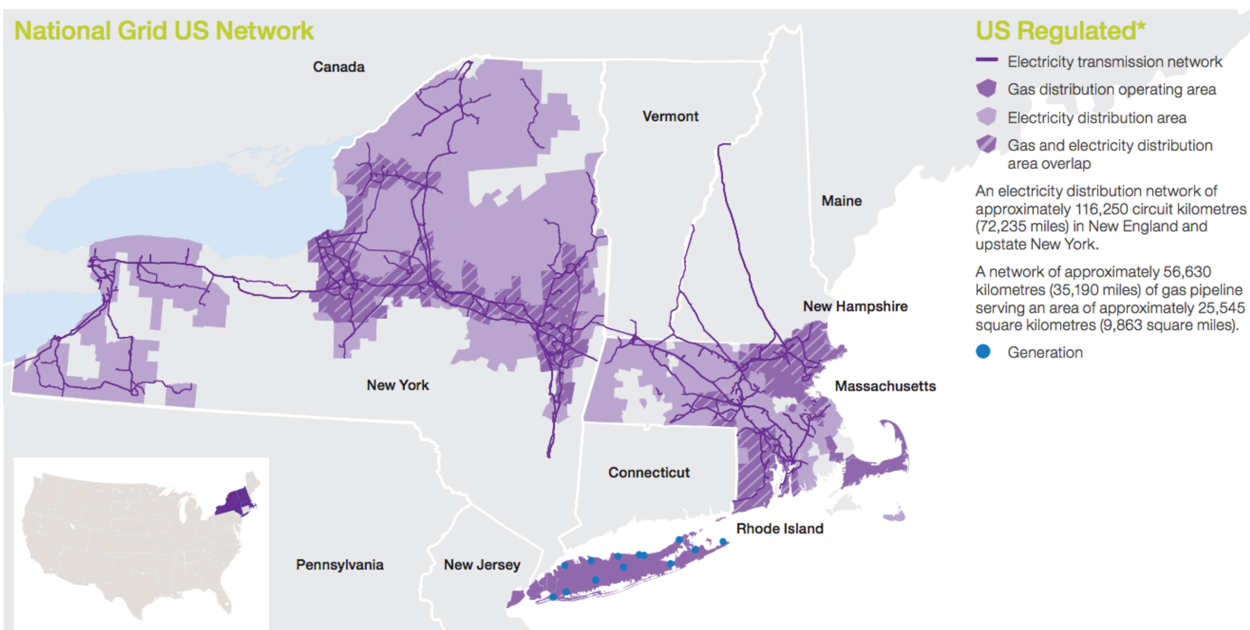
1. Summary

U.S. Electric Distribution System

National Grid's U.S. electric distribution system is comprised of three companies serving over 3 million customers in Massachusetts and upstate New York. The three electric distribution companies are Massachusetts Electric Company and Nantucket Electric Company, serving 1.35 million customers in Massachusetts; and Niagara Mohawk Power Company, serving 1.7 million customers in Upstate New York.

Massachusetts Electric Company

Massachusetts Electric Company (MECO) makes up 36% of electric deliveries in the U.S. for National Grid. Figure 1 shows National Grid's service territory in the U.S.[1].



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Figure 1: National Grid Service Territory[1]

MECO's service territory is approximately 43% residential, 44% commercial and 13% industrial by volume. It spans across the entire state, including all or some portions of all counties, except Dukes and Barnstable counties.

From fiscal year 2018 to fiscal year 2023, Massachusetts Electric weather normalized deliveries averaged a 0.8% annual <u>decline</u>. For the fiscal year 2023 to date, i.e. from April 2022 to August

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[1] As of May 22, 2022, National Grid has completed the sale of The Narragansett Electric Company ("NECO") to PPL Rhode Island Holdings, LLC. Thus, Rhode Island is not part of National Grid's U.S. electric distribution system after the completion of the sale.

2022, and what is expected for the remainder of the fiscal year (through March 2023), the total energy is expected to grow 0.7% from the previous fisical year. Residential deliveries are expected to increase by 1.4%, commercial deliveries are expected to remain similar as the previous fisical year, and industrial deliveries are expected to increase by 1.0%.

In the next five calendar years, the annual deliveries are expected to continue to grow by 1.0% after impacts for Distributed Energy Resources (DERs). The DERs included are energy efficiency (EE) programs, solar-photovoltaics (PV), electric vehicles (EV), and electric heat pumps (EH). Before the impacts of these DERs, it is projected that growth would have been positive 1.4% per year.

Figure 2 shows the annual total energy in both GWh and annual percent change. The energy is expected to grow year over year for the five-year forecast horizon. The residential sector is expected to grow year over year between FY2024 and FY2028 with customer counts and residential usage being expected to grow and net DER reduction being expected to decrease (due to the electrifications in the transportation and heating sectors) in later years. The commercial sector is expected to continue to grow post the pandemic but at a more stable and sustainable rate comparing to FY2022. The industrial sector is expected to show decline aligning with its long-term historical trend. Table 1 shows total historical and forecast deliveries by revenue class for the Massachusetts Electric Company.

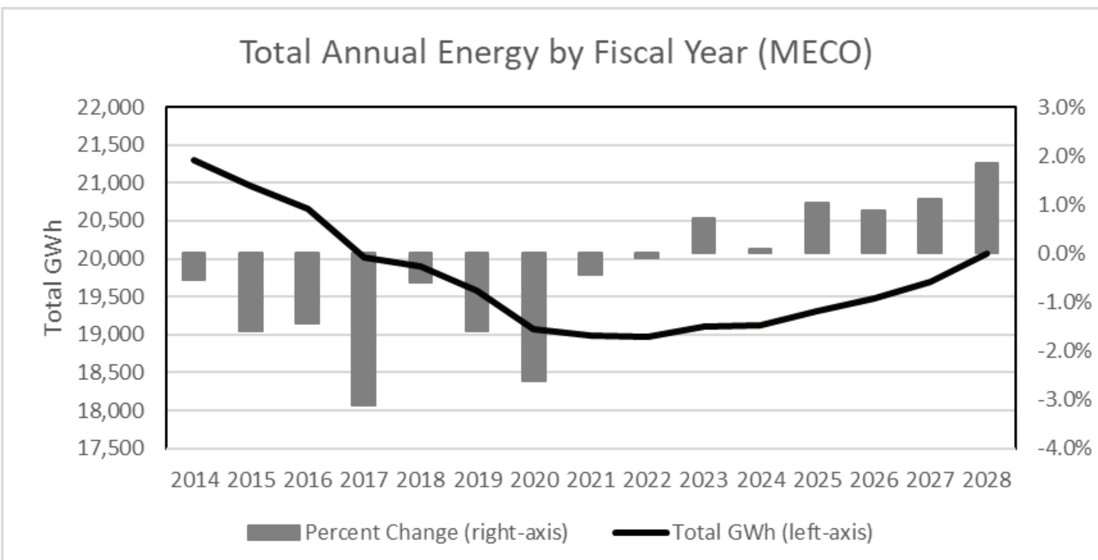

Figure 2: Annual Total Energy by Fiscal Year

Table 1: Total historical and forecasted deliveries by revenue classes (MECO)

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class — After Energy Efficiency, Solar and Electric Vehicle Impacts														
FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		M		TOTAL	
2008	7,708.3		945.2		8,653.5		9,443.7		3,766.2		110.2		10.3		21,973.5	
2009	7,649.1	-0.8%	919.5	-2.7%	8,568.6	-1.0%	9,439.6	0.0%	3,703.1	-1.7%	110.2	0.0%	9.9	-4.2%	21,821.5	-0.7%
2010	7,737.6	1.2%	906.9	-1.4%	8,644.5	0.9%	9,257.1	-1.9%	3,394.8	-8.3%	109.0	-1.1%	9.5	-3.6%	21,405.4	-1.9%
2011	7,831.8	1.2%	903.4	-0.4%	8,735.2	1.0%	9,177.5	-0.9%	3,362.5	-1.0%	108.7	-0.2%	9.7	2.5%	21,384.0	-0.1%
2012	7,874.2	0.5%	895.5	-0.9%	8,769.7	0.4%	9,221.0	0.5%	3,268.8	-2.8%	108.4	-0.3%	9.0	-8.0%	21,368.0	-0.1%
2013	7,991.1	1.5%	895.4	0.0%	8,886.4	1.3%	9,218.6	0.0%	3,203.3	-2.0%	109.4	0.9%	9.3	3.5%	21,417.7	0.2%
2014	8,014.6	0.3%	898.6	0.4%	8,913.2	0.3%	9,141.9	-0.8%	3,140.8	-2.0%	106.6	-2.6%	9.6	3.3%	21,302.5	-0.5%
2015	7,737.7	-3.5%	872.1	-2.9%	8,609.8	-3.4%	9,095.6	-0.5%	3,145.9	0.2%	110.4	3.6%	8.6	-10.5%	20,961.8	-1.6%
2016	7,512.6	-2.9%	824.1	-5.5%	8,336.7	-3.2%	9,134.9	0.4%	3,080.5	-2.1%	107.8	-2.4%	6.7	-22.0%	20,659.8	-1.4%
2017	7,337.1	-2.3%	796.5	-3.3%	8,133.7	-2.4%	8,924.3	-2.3%	2,853.1	-7.4%	103.5	-4.0%	7.1	6.2%	20,014.5	-3.1%
2018	7,320.9	-0.2%	801.9	0.7%	8,122.8	-0.1%	8,896.3	-0.3%	2,776.6	-2.7%	99.6	-3.8%	6.4	-9.5%	19,895.2	-0.6%
2019	7,277.8	-0.6%	782.7	-2.4%	8,060.4	-0.8%	8,815.3	-0.9%	2,623.1	-5.5%	80.5	-19.2%	6.9	7.1%	19,579.3	-1.6%
2020	7,043.8	-3.2%	763.4	-2.5%	7,807.3	-3.1%	8,671.5	-1.6%	2,511.5	-4.3%	75.4	-6.3%	6.3	-9.0%	19,065.7	-2.6%
2021	7,686.1	9.1%	774.2	1.4%	8,460.3	8.4%	8,039.9	-7.3%	2,421.3	-3.6%	59.1	-21.6%	6.1	-2.0%	18,980.6	-0.4%
2022	7,380.0	-4.0%	763.3	-1.4%	8,143.3	-3.7%	8,330.9	3.6%	2,433.9	0.5%	56.0	-5.2%	6.0	-1.9%	18,964.1	-0.1%
2023	7,514.9	1.8%	739.6	-3.1%	8,254.4	1.4%	8,327.0	0.0%	2,458.1	1.0%	60.5	8.0%	6.0	-1.0%	19,100.1	0.7%
2024	7,511.8	0.0%	765.2	3.5%	8,277.1	0.3%	8,346.2	0.2%	2,427.5	-1.2%	64.2	6.1%	6.0	0.0%	19,114.9	0.1%
2025	7,649.2	1.8%	780.5	2.0%	8,429.7	1.8%	8,418.8	0.9%	2,401.3	-1.1%	63.6	-0.9%	6.0	0.0%	19,313.4	1.0%
2026	7,781.5	1.7%	796.5	2.0%	8,578.0	1.8%	8,483.6	0.8%	2,359.2	-1.8%	63.0	-0.9%	6.0	0.0%	19,483.8	0.9%
2027	7,951.9	2.2%	817.8	2.7%	8,769.7	2.2%	8,554.8	0.8%	2,312.2	-2.0%	62.4	-0.9%	6.0	0.0%	19,699.1	1.1%
2028	8,207.0	3.2%	847.2	3.6%	9,054.2	3.2%	8,666.8	1.3%	2,277.9	-1.5%	61.9	-0.9%	6.0	0.0%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.2%		-1.6%		-0.3%		-0.8%		-2.8%		-3.9%		-3.6%		-0.9%
prior 10 years		-0.6%		-1.9%		-0.7%		-1.0%		-2.6%		-5.8%		-4.3%		-1.1%
prior 5 years		0.5%		-1.6%		0.3%		-1.3%		-2.4%		-9.5%		-1.5%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.8%		2.8%		1.9%		0.8%		-1.5%		0.5%		0.0%		1.0%

Nantucket Electric Company

The Nantucket Electric Company comprises less than 1.0% of total U.S. deliveries for National Grid. The company's Nantucket service territory is approximately 68% residential and 32% non-residential. It covers the whole island.

Nantucket weather normalized deliveries growth from fiscal year 2018 to fiscal year 2023 averaged <u>negative</u> 2.3% per year.

In the next five calendar years, annual growth is expected to continue to <u>grow</u> by 0.9% after impacts for Distributed Energy Resources (DERs). The DERs included are energy efficiency (EE) programs, solar-photovoltaics (PV) and electric vehicles (EV) for all sectors, and electric heat pumps (EHP) for the residential sector only. Before the impacts of these DERs, it is projected that growth would have been the same <u>positive</u> 1.2% per year.

Figure 3 shows the annual total energy in both GWh and annual percent change. The energy is expected to grow for the five-year forecast horizon.

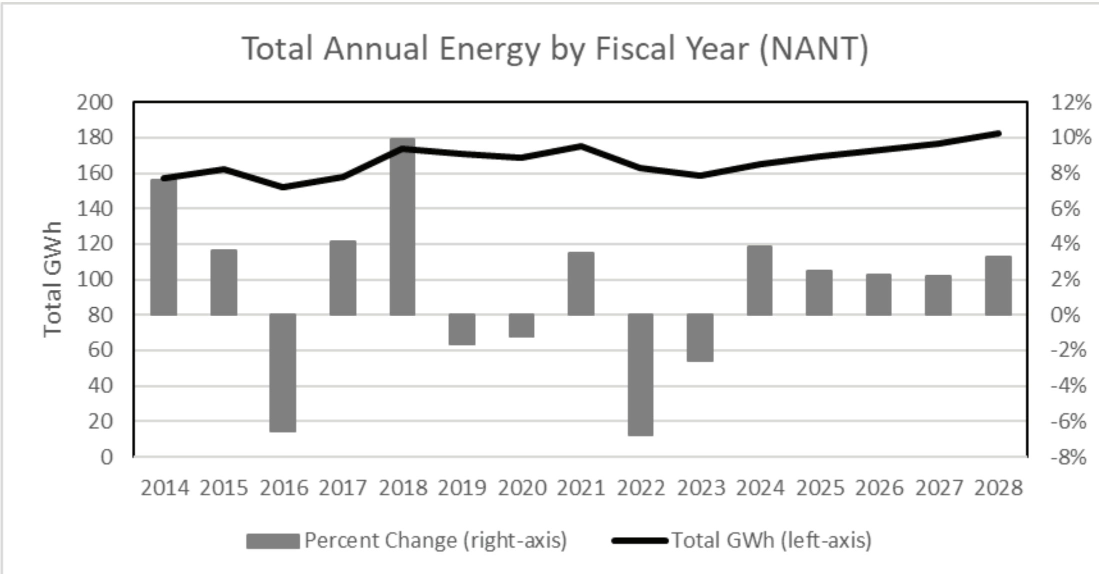

Figure 3: Annual Total Energy by Fiscal Year

Table 2 shows total historical and forecast deliveries for Nantucket Electric.

Table 2: Total historical and forecasted deliveries by revenue classes (Nantucket)

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solarr, Electric Vehicle, and Electric Hear Pump Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	93.3		1.9		95.3		49.4		0.8		0.3		145.8	
2009	92.1	-1.3%	1.7	-9.8%	93.8	-1.5%	49.1	-0.6%	0.9	9.2%	0.3	8.1%	144.1	-1.1%
2010	92.1	0.0%	1.7	-1.7%	93.8	-0.1%	50.7	3.2%	1.0	4.3%	0.3	-1.3%	145.7	1.1%
2011	88.1	-4.3%	1.5	-14.6%	89.6	-4.5%	48.8	-3.8%	1.0	6.2%	0.3	-1.7%	139.6	-4.1%
2012	91.6	3.9%	1.5	3.5%	93.1	3.9%	50.1	2.7%	1.0	1.9%	0.3	0.2%	144.5	3.5%
2013	93.5	2.0%	1.5	-0.1%	95.0	2.0%	49.5	-1.2%	1.0	-2.5%	0.3	-0.3%	145.7	0.8%
2014	101.7	8.8%	1.7	10.7%	103.4	8.8%	52.2	5.6%	1.0	-6.1%	0.3	1.1%	156.8	7.6%
2015	105.4	3.6%	1.7	1.5%	107.1	3.6%	54.2	3.9%	0.9	-1.6%	0.3	-0.9%	162.5	3.7%
2016	98.4	-6.6%	1.6	-8.3%	100.0	-6.6%	50.6	-6.7%	1.0	10.6%	0.3	-0.1%	151.9	-6.5%
2017	104.3	5.9%	1.6	1.9%	105.8	5.9%	51.2	1.1%	1.0	-7.8%	0.3	0.1%	158.2	4.2%
2018	111.4	6.8%	1.7	9.1%	113.1	6.9%	59.8	17.0%	0.7	-24.9%	0.3	0.4%	173.9	9.9%
2019	111.1	-0.3%	1.7	-3.9%	112.8	-0.3%	57.4	-4.1%	0.7	-3.5%	0.3	1.0%	171.1	-1.6%
2020	112.5	1.3%	1.6	-0.9%	114.2	1.2%	53.9	-6.0%	0.6	-7.6%	0.3	-1.2%	169.0	-1.2%
2021	118.7	5.5%	1.7	2.0%	120.4	5.5%	53.7	-0.5%	0.6	-9.0%	0.3	-0.3%	174.9	3.5%
2022	110.1	-7.3%	1.5	-8.6%	111.6	-7.3%	50.6	-5.8%	0.7	18.9%	0.3	-0.6%	163.1	-6.8%
2023	108.1	-1.8%	1.4	-6.8%	109.6	-1.8%	48.4	-4.4%	0.8	12.7%	0.2	-8.0%	158.9	-2.6%
2024	111.5	3.1%	1.4	0.8%	113.0	3.1%	51.1	5.7%	0.7	-5.0%	0.3	9.3%	165.1	3.9%
2025	114.5	2.7%	1.5	4.6%	116.1	2.7%	52.1	2.0%	0.7	-2.0%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	4.0%	119.0	2.5%	53.1	1.8%	0.7	-1.9%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	3.0%	121.8	2.4%	54.0	1.8%	0.7	-1.8%	0.3	0.0%	176.8	2.2%
2028	124.4	3.5%	1.7	4.1%	126.1	3.5%	55.5	2.7%	0.7	-1.7%	0.3	0.0%	182.6	3.3%
Annual Growth Rates:														
prior 15 years		1.0%		-2.0%		0.9%		-0.1%		-0.5%		-0.3%		0.6%
prior 10 years		1.5%		-0.5%		1.4%		-0.2%		-2.6%		-0.9%		0.9%
prior 5 years		-0.6%		-3.7%		-0.6%		-4.2%		1.7%		-1.9%		-1.8%
BASE YEAR:	**2023**													
next 5 years		2.9%		3.3%		2.9%		2.8%		-2.5%		1.8%		2.8%

1.1. Forecast Methodology

The Company's electric deliveries and customer counts forecast is developed from econometric models relating monthly deliveries by company and class of service to regional economic and/or demographic variables, weather, and other explanatory variables. The models estimate the historical relationship between deliveries and these variables. The models then predict future deliveries based on forecasts of the explanatory variables. The total residential, residential electric heating, and commercial models are specified as energy use-per-customer models. Separate models are developed for customer counts. The use-per-customer model results are multiplied by the customer count model results to determine overall energy deliveries. The industrial models are specified directly as total deliveries.

All energy models are specified after reconstituting the historical deliveries for Distributed Energy Resources (DER). That is, after adding back the impacts of these DERs to the historical input dataset. The DER that are included are: energy efficiency (EE), solar-PV (PV), electric vehicles (EV), and electric heat pumps (EH). The model-produced GWh delivery forecast results are then adjusted to reflect projected cumulative DER impacts.

Class of service deliveries and customer forecasts are allocated to rate classes based on historical trends.

All models are checked for overall goodness of fit and statistical validity.

1.2. Regional Economic Drivers

The historical and forecast economic explanatory variables are obtained from Moody's Analytics. Moody's provides economic forecasts at the U.S., state, metro, and county levels. The Company aligns these areas with each operating company to develop load forecasts. Key economic drivers are number of households for the customer counts forecasting in the residential and commercial sectors, manufacturing employment for the customer counts forecasting and energy forecasting in the industrial sector, and gross state product (GSP) for energy usage per customer count forecasting in the commercial sector. Time trend is used for the residential energy usage per customer count forecasting. The Moody's Baseline forecast released in August 2022 was used. The forecast assumes that the Federal Reserve will continue to raise interest rates until it reaches its inflation target in early 2024. The economy should reach full employment later this year, which enables the Federal Reserve to continue with its quantitative tightening policy. High inflation is largely due to higher energy and commodity prices brought on by the recent geo-political actions and the lingering supply chain constraints. The forecast assumes a modest increase in oil prices in the fourth quarter before they steadily decline in 2023 and the first half of 2024. Oil prices bottom in 2024, a touch below $65 per barrel and each new wave of COVID-19 is assumed to be less disruptive to the supply chain than the preceding wave.The Inflation Reduction Act (IRA), which passed the Senate recently, has been incorporated in the August baseline forecast. The IRA is estimated to reduce U.S. inflation, as measured by the consumer price index, by 3.3 basis points per year on average over the next 10 years.The forecast also assumes that the economic activity is not severely hampered by COVID-19 and the case counts will remain below the peak in January 2022 due to widespread vaccinations and new treatments. Overall, real Gross Domestic Product (GDP) growth is forecast to rise by 1.6% in 2022, by 1.5% in 2023 and averaging about 2.8% per year between 2024-2027. Though the U.S. labor market remains very strong, it is set to moderate. The forecast is for the unemployment rate to gradually increase in the second half of 2022, averaging 3.7% in the fourth quarter. The unemployment rate keeps rising in 2023 because of below-potential GDP growth and job growth and is expected to average 4.0% for the years 2024-2027.

The figures below show economic indicators for each of the Companies in each of the service territories in the Northeast in addition to the U.S. overall. This provides comparative values to the subject service territory.

Figure 4 summarizes Moody's forecast for number of households. Households can provide an indication of the overall load growth in a region as more households can translate into more residential load as well as more commercial load as more consumers support the local economy. In the year 2023, it is expected to remain a similar growth rate as in the previous two years. For the rest of the planning horizon, the region's number of households is expected to continue the growth at a rate that is less than the national average.

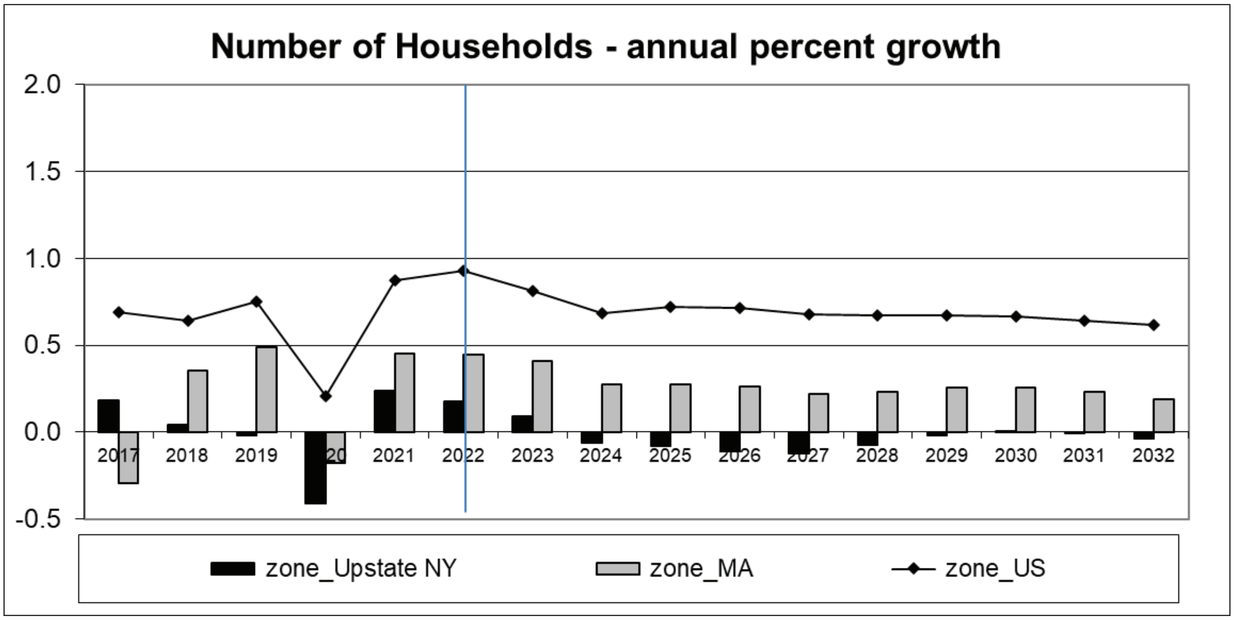

Figure 4: Number of households growth of Upstate NY, MA, and the U.S.

Figure 5 summarizes the forecast for gross state product (GSP). GSP can provide an overall indication of the strength of the economy. A stronger economy can translate to more load in all sectors, notwithstanding the offsetting impacts of DERs. Annual growth in MA significantly declined in 2020 due to the pandemic, and strong rebound was observed in 2021 and remained grow in 2022. For the planning horizon, the growth rate settles into between two and three percent per year that is about the same as the U.S.

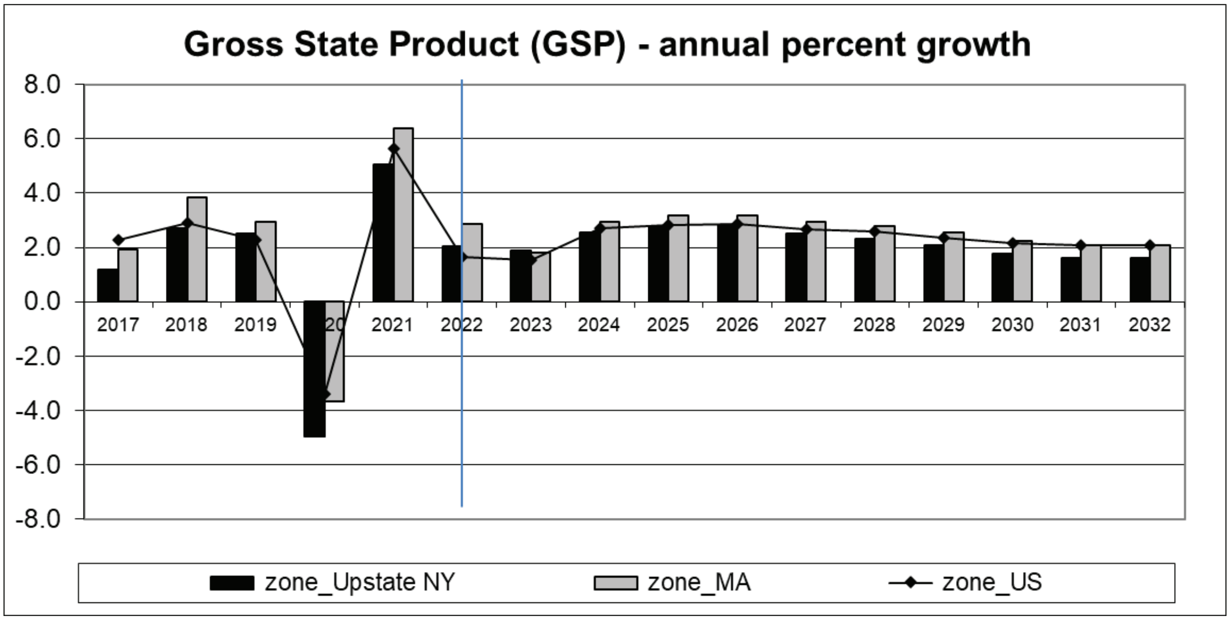

Figure 5: GSP growth of Upstate NY, MA, and the U.S.

Figure 6 summarizes the forecast for manufacturing employment. All regions and the country experienced recovery in 2021 and 2022 from the significant decline in the year 2020. Some growth is projected for the next two years, and then it is expected to return to a longer-term negative growth less than 1.0% per year. This longer-term trend is consistent with the region's longer-term historical trend.

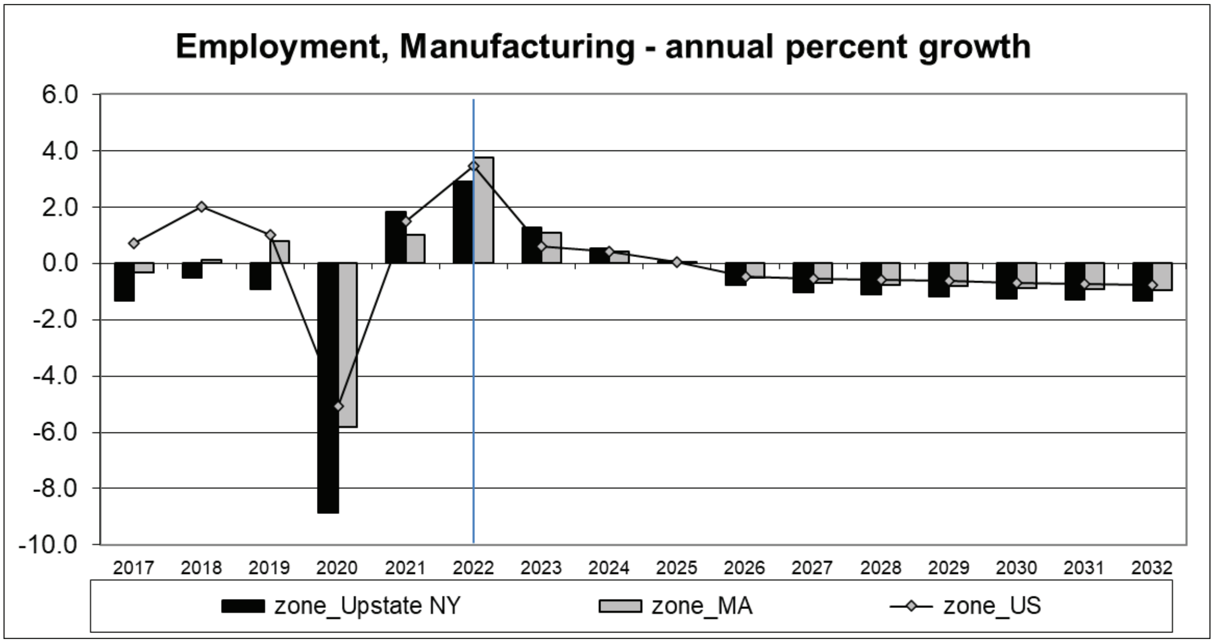

Figure 6: Manufacturing employment growth of Upstate NY, MA, and the U.S.

Nantucket Island tends to run higher economically for all categories compared to the state overall.

1.3. Weather Assumptions

Weather data is collected from the major weather stations located within the Company's service territory and used to model, forecast, and weather-normalize GWh deliveries. The relevant weather stations are Boston, Worcester, Nantucket, Providence (due to its proximity to southeastern Massachusetts) and Albany (due to its proximity to western Massachusetts). These most closely represent the company's service territory.

Seasonal heating and cooling degree days are used to model the relationship between energy deliveries and weather. Cooling degree-days (CDD) are equal to average daily temperature minus 65 degrees (however no less than zero). The more CDDs over a given period, the hotter the daily temperatures are. Heating degree-days (HDD) are equal to 65 degrees minus average daily temperature (but no lower than zero). The more HDDs over a given period, the colder it is.

Since customers are billed on a cycle throughout the month, billed GWh deliveries reflect energy consumed during part of the current month and part of the previous month. HDDs and CDDs must reflect this same consumption pattern. This is accomplished by using meter reading schedules to match daily degree days with the days between reading dates for each one of the 20 billing cycles, then taking the average of degree days over the 20 cycles.

The forecast report provides historical data in terms of actual and weather-adjusted (or weather-normalized) energy results. It also provides future projections on a weather-normalized basis. Results are weather-normalized by taking the ten-year average of HDD and CDD and incorporating these into the regression models. By updating the normal values each year with the most current history any changes in longer-term trends in weather are captured.

Figures 7 & 8 below show the annual actual and weather-normal HDD and CDD used in the analysis in this report for MECO. Actual HDD and CDD are the actual degree days by billing months for each year and normal HDD and CDD are the ten-year average degree days by billing months from 2012 to 2021.

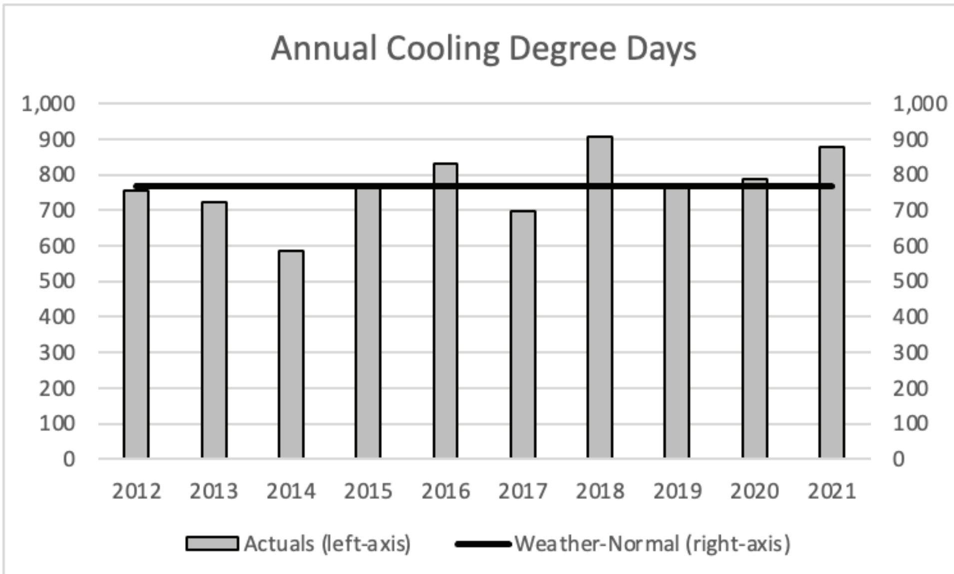

Figure 7: MECO annual cooling degree days

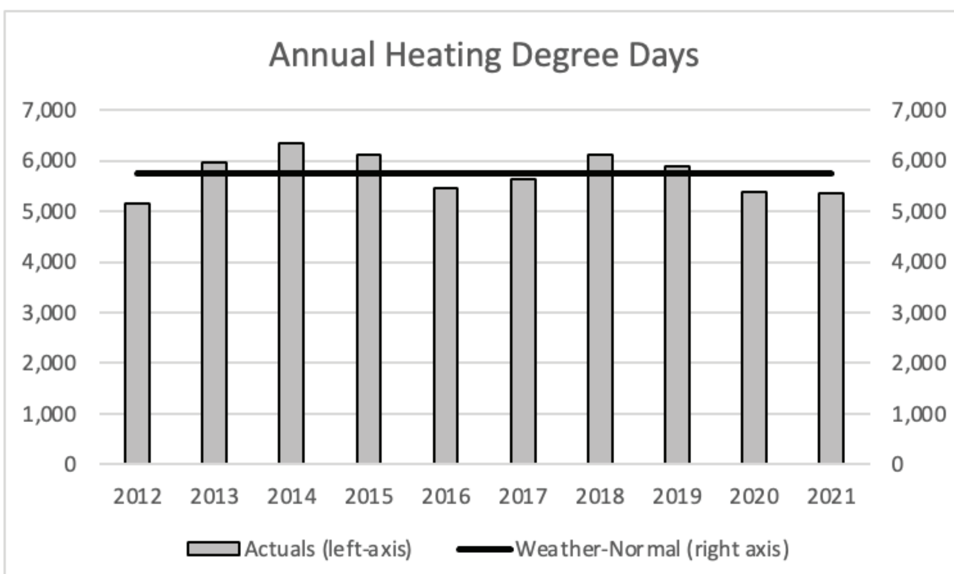

Figure 8: MECO Annual Heating Degree Days

Figure 9 shows the cyclical nature of the weather normalized cooling and heating degree days. The forecasts are based on billing month (solid lines). For comparative purposes, calendar month billing days are also shown. In general, the billing month degree-days have a lag compared to the calendar month degree-days. This is because the billing degree months have part current month and part prior month in them due the nature of bill reads. For example, the billing month of July would have degree days in both July and the prior month June, while calendar month July would have only July days.

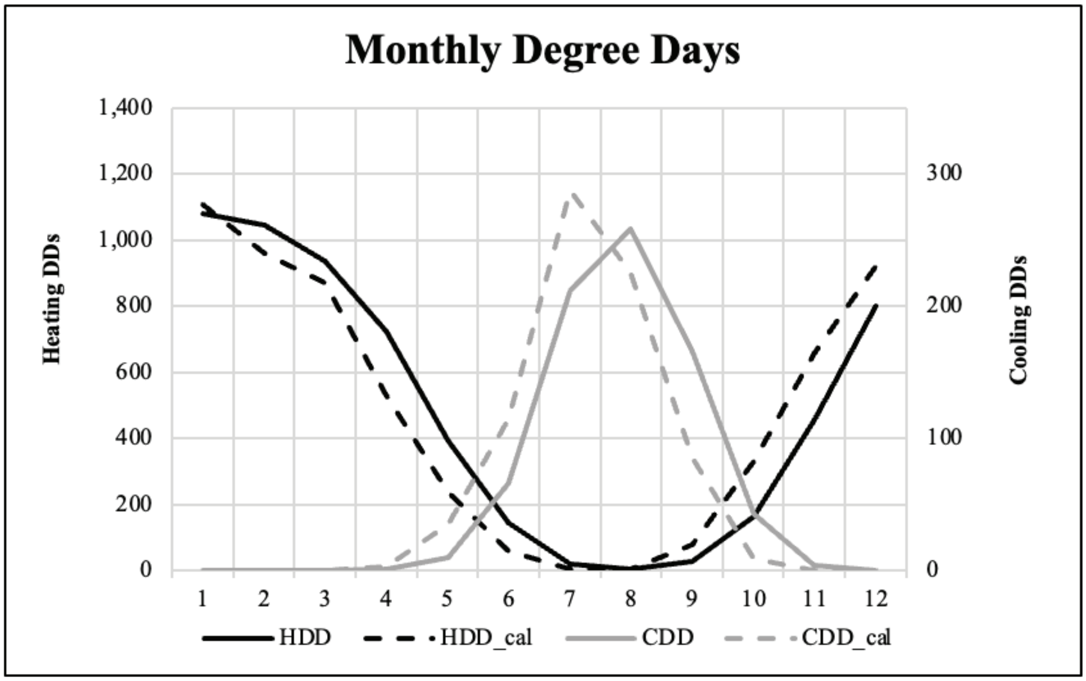

Figure 9: MECO Monthly Degree Days

Figures 10 and 11 show the annual heating and cooling degree days used in the analysis for Nantucket.

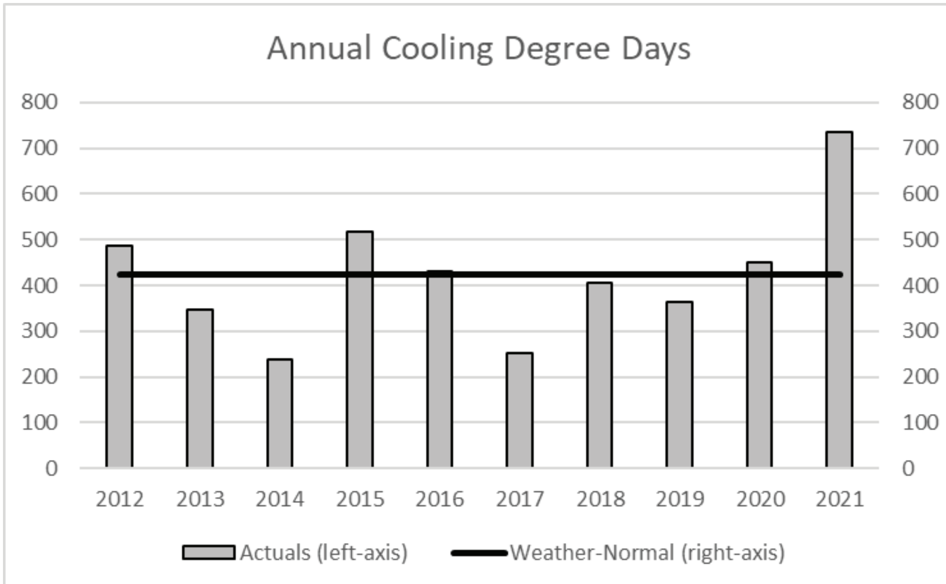

Figure 10: Nantucket Annual Cooling Degree Days

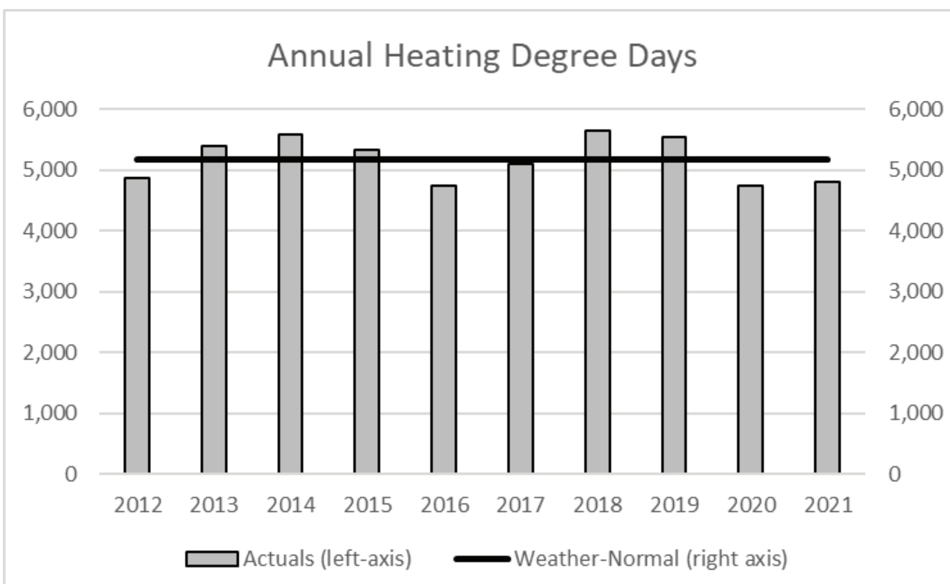

Figure 11: Nantucket Annual Heating Degree Days

Figure 12 shows the monthly weather normalized cooling and heating degree days for Nantucket.

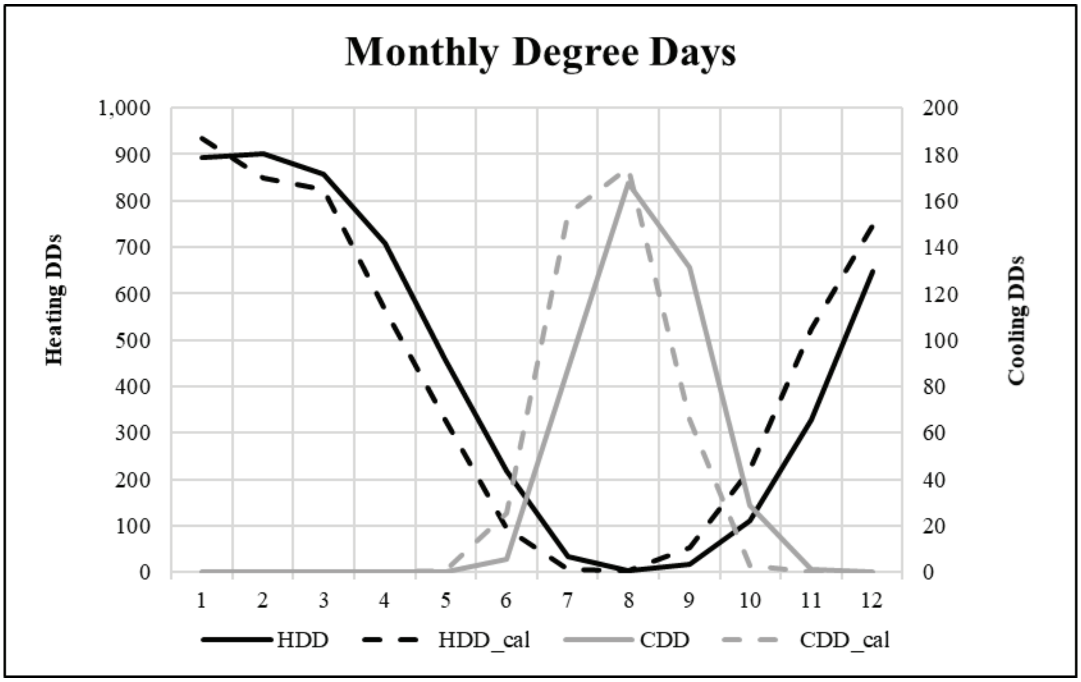

Figure 12: Nantucket Monthly Degree Days

1.4. Distributed Energy Resources (DERs)

In New England, there are a number of policies, programs, and technologies impact customer energy consumption. These include energy efficiency (EE), solar-photovoltaics (PV) and electric vehicles (EV) and electric heat pumps (EH). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to at traditional, centralized power supplies. Demand Response (DR) and Energy Storage (ES) are accounted for in the peak forecast but do not materially impact energy consumption and are therefore not included here.

For MECO, Figure 13 shows the expected energy each year. The solid line shows the annual energy after the impacts of DERs and the dashed line shows the annual energy before those impacts. Figure 14 shows the impacts for the DERs each year. Figure 15 and 16 present the same for NANT.

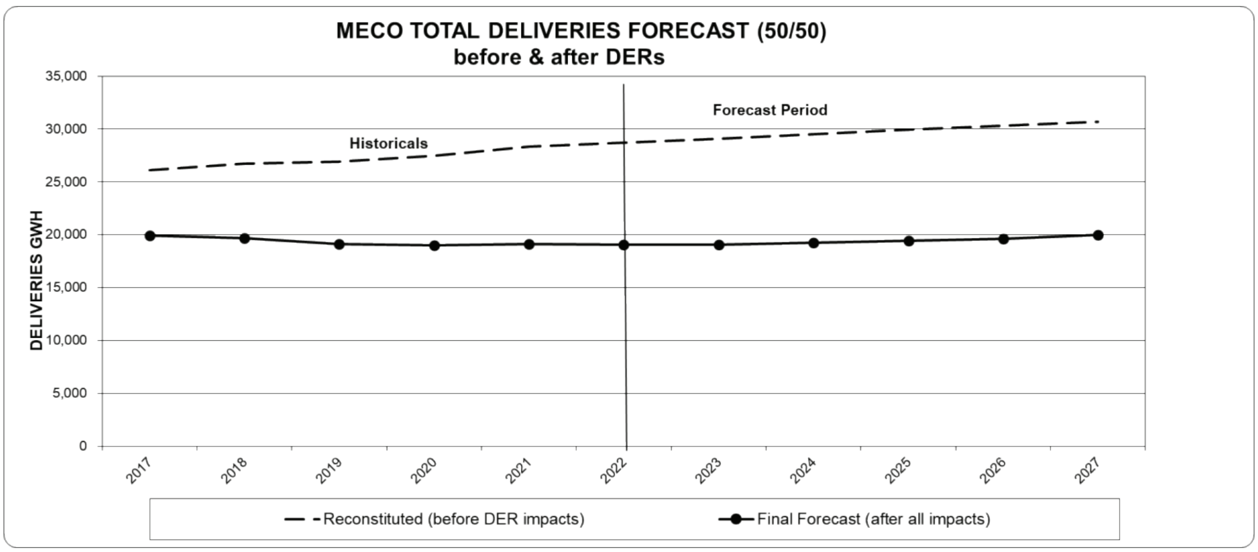

Figure 13: MECO Annual Loads before and after the impact of DERs

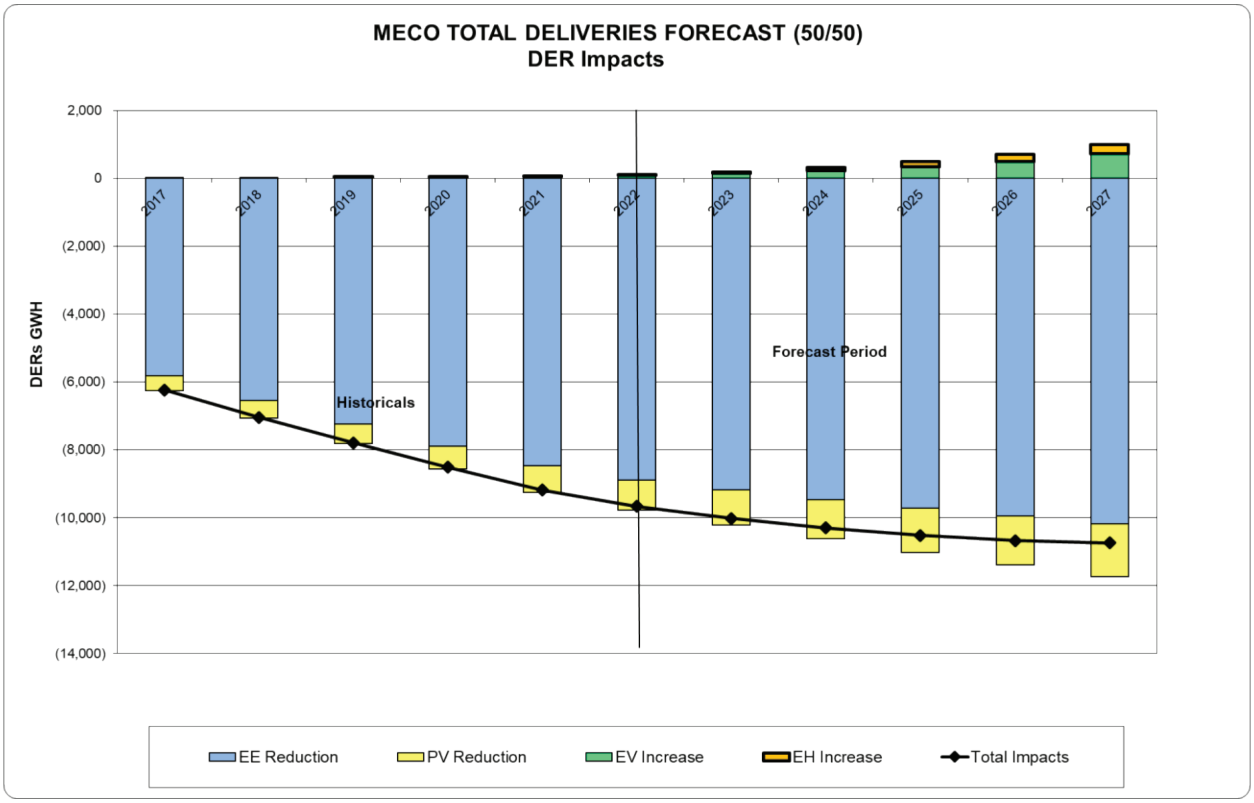

Figure 14: MECO Annual Impact of DERs

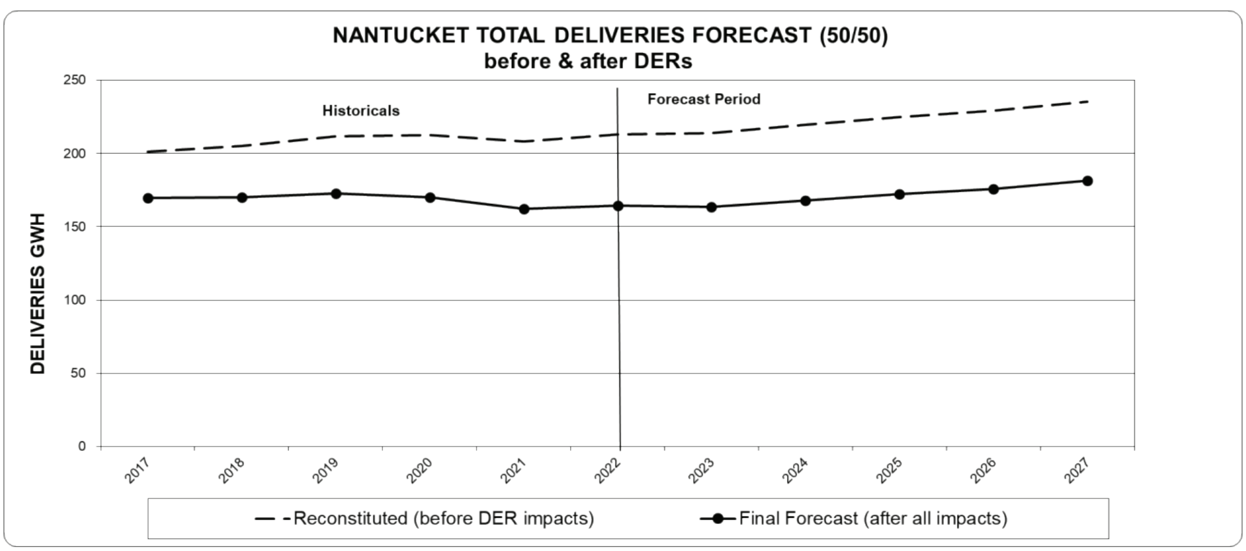

Figure 15: NANT Annual Loads before and after the impact of DERs

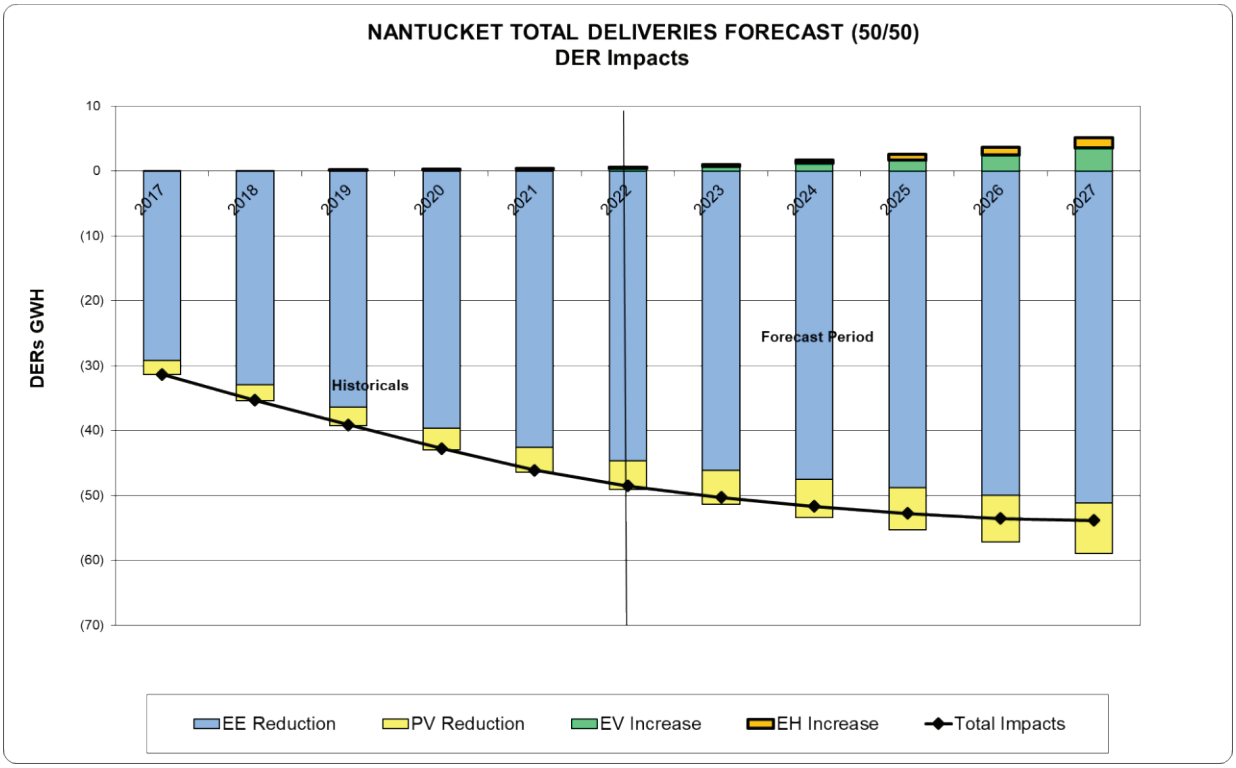

Figure 16: NANT Annual Impact of DERs

1.4.1 Energy Efficiency (EE)

National Grid has EE programs in its Massachusetts jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term (one to three years), EE targets are based on Company annual plan from the Subject Matter Experts (SMEs) through 2024. Beyond 2024, the cumulative value of persistent EE savings is still expected to continue to grow but at a slower rate each year.

Figure 14 and 16 above shows the expected <u>deduction</u> to annual consumption for MECO and NANT by year. For MECO, as of 2022, it is estimated that these EE programs have reduced annual energy by 8,882 GWh, or 31.0% compared to the counterfactual with no EE programs. By 2027, it is expected that this reduction will grow to 10,177 GWh or 33.2% of what load would have been had these programs not been implemented. EE is expected to decrease future growth (before any DERs) from 1.4% per year to 0.7% per year on average over the next five years. Figure 17 presents the annual incremental (left) and cumulative (right) EE annual GWh.

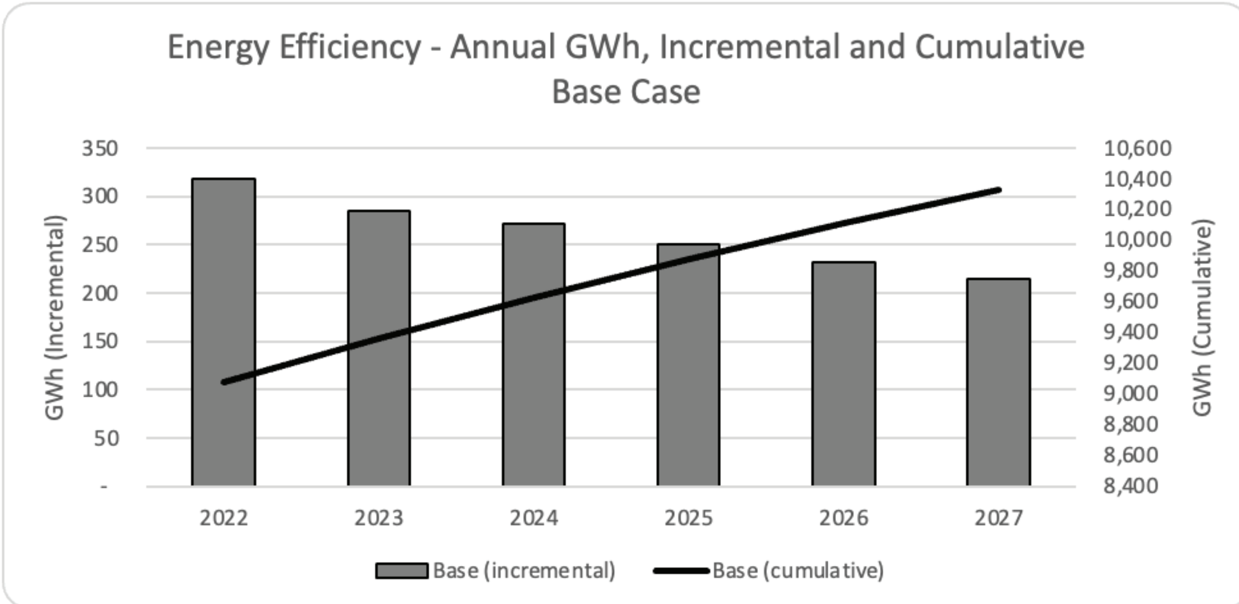

Figure 17: Massachusetts Incremental and Cumulative EE Forecasts (in service territory)

1.4.2 Solar-Photovoltaics (PV)

There has been a rapid increase in the adoption of PV throughout the state. The actual installed PV is tracked by the Company and used for the historical values. The near-term (2023-2027) predictions leveraged the information on the projects in the Company's queue and the insights from PV subject matter experts at the Company, and also assumes National Grid fills its share (i.e. 45%) of the State's existing solar standards of 3.2 GW by the end of the forecast horizon.

As of 2022, Company's Massachusetts service territory has about 1,745 MW[2] installed PV. This is expected to grow to about 2,607 MWs by 2027. Figure 18 shows the expected installed nameplate MW for PVs.

[2] AC nameplate capacity

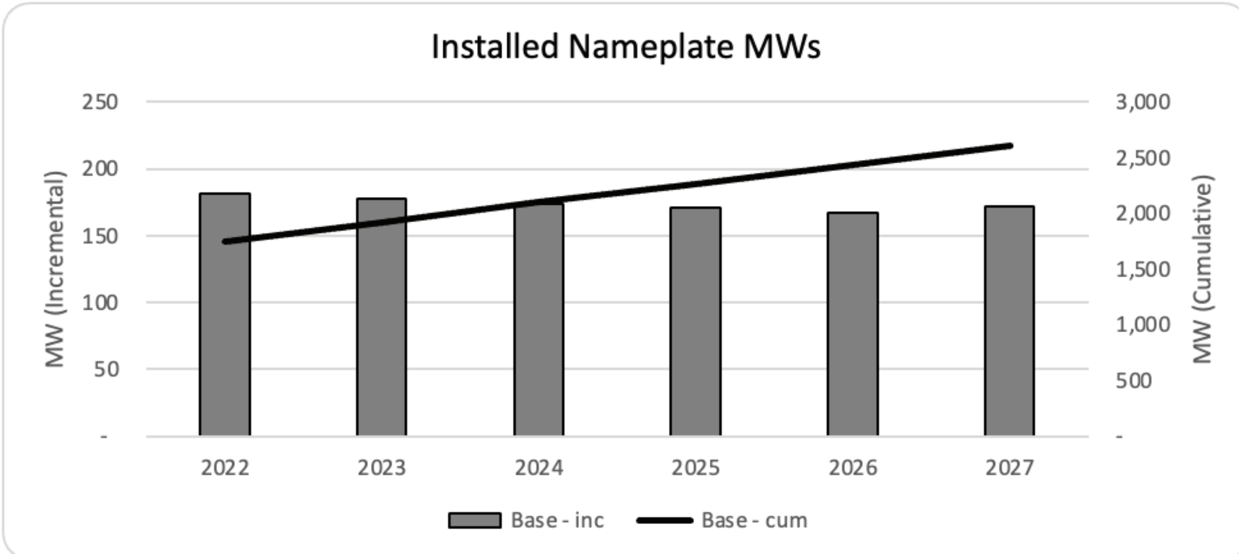

Figure 18: Massachusetts PV Nameplate in MW (in service territory)

Figure 14 and 16 above shows the expected deduction to annual consumption for MECO and NANT by year. As of 2022, it is estimated that this technology has already reduced MECO loads by 897 GWh, or 3.1% annually. By 2027 it is expected that these reductions may grow to 1,559 GWh, or 5.1% annually of what consumption would have been had this technology not been installed. Over the five-year planning horizon these reductions lower annual growth (before any DERs) from 1.4% to 1.0% per year.

1.4.3 Electric Vehicles (EV)

Electric vehicles increase energy consumption over time. Electric vehicles of interest are those that plug-in to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that have impacts on the electric network. Light-duty EVs, medium-duty EVs, heavy-duty EVs and electric buses are considered in this forecast.

The light-duty vehicle (LDV) base case is developed around California's Advanced Clean Car II (ACC-II) rules[3], which are expected to be adopted by Massachusetts. In the near-term, the zero-emission vehicle share of LDV sales is created based on the techno-economic potential and current market trends. In the medium-term (2026 -2030), the zero-emission vehicle sales projection aligns with the ACC-II case allowing flexibilities[4], reaching to 59.5% by 2030. The adoptions of medium-duty EV (MDEV), heavy- duty EV (HDEV) and E-buses is based on the California's Advanced Clean Trucks (ACT) rules through 2035 which have been adopted by the

[3] https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii

[4] Flexibilities include provisions to transfer ZEV "sales values" across all states that have adopted the regulations (e.g., a manufacturer can overachieve in California and underachieve elsewhere), provisions to sell affordable EVs in environmental justice areas, and using historical ZEV sales credits to meet the annual ZEV sales targets. All of the flexibilities provided in the rules expire by or before 2031.

state. The sales shares for MDEV, HDEV, and E-buses are estimated to be about 63%, 40%, and 75% of MDV, HDV, and buses, respectively, by the end of 2035.

Figure 19 shows the estimated number of EVs in the Company's Massachusetts service territory. As of the end of 2022, it is estimated that about 32,200 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the Company's Massachusetts service territory, growing to about about 206,400 by 2027.

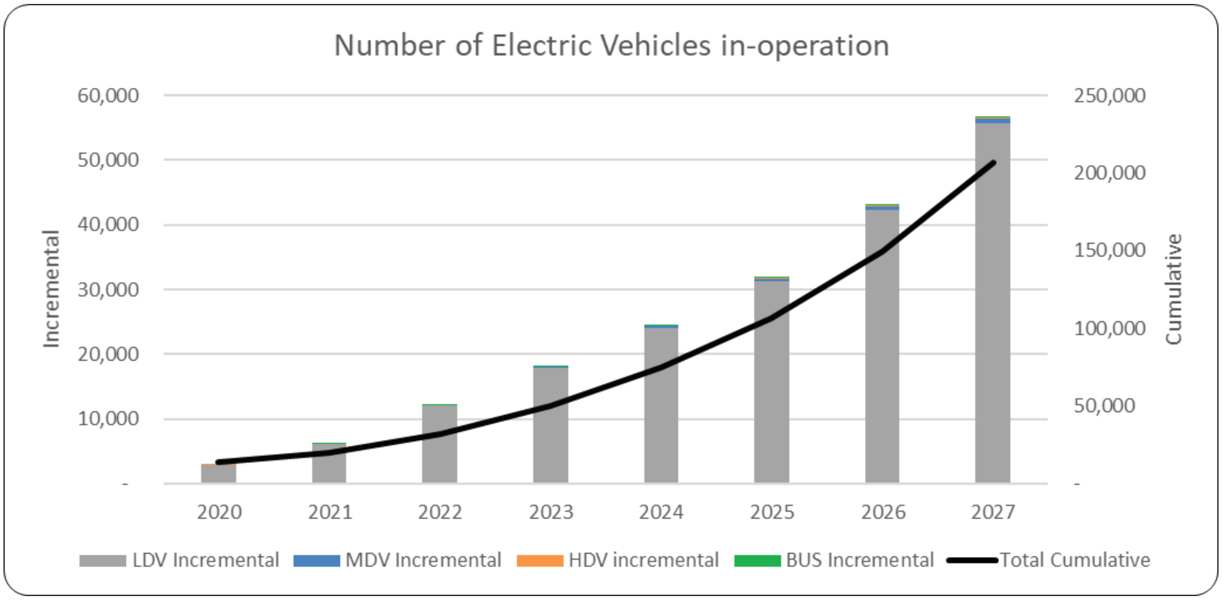

Figure 19: Massachusetts Number of Electric Vehicles (in service territory)

Figure 14 & 16 above shows the expected increase to annual consumption by year. Electric vehicles annual energy impacts are estimated for light-duty, medium-duty, heavy-duty, and electric buses separately. The annual energy impact of light-duty EVs is estimated to be 3,316 kWh per EV in year 2022 and gradually grow to 3,688 kWh per EV by 2027 in anticipating the increasing share of BEV types. For medium-duty EVs, heavy-duty EVs, and electric buses, the annual energy impacts are estimated to be 11,847 kWh per EV, 38,848 kWh per EV, and 100,839 kWh per EV, respectively. For MECO, as of 2022, it is estimated that this technology may have already added 89 GWh, or 0.3% to energy consumption. By 2027 it is expected that the impact from this techonoloy may grow to 722 GWh, or 2.4% of what consumption would have been had this technology not been installed. Over the five-year planning horizon these raise annual growth (before any DERs) from 1.4% to 1.8% per year.

1.4.4 Electric Heat Pumps (EH)

The base case is based on the Company's heat pump targets until 2024. Post 2024, the Company assumes it's pro rata share of CECP phased pathway's target in 2050 will be met[5]. Figure 20 shows the annual number of full and partial electric heat pumps assumed in the Company's Massachusetts service territory[6]. A full heat pump is defined as a unit will serve the all the heating and cooling in the home or building. A partial heat pump is defined as a unit that will supplement existing heating system, as well as cool the home or building during the summer season.

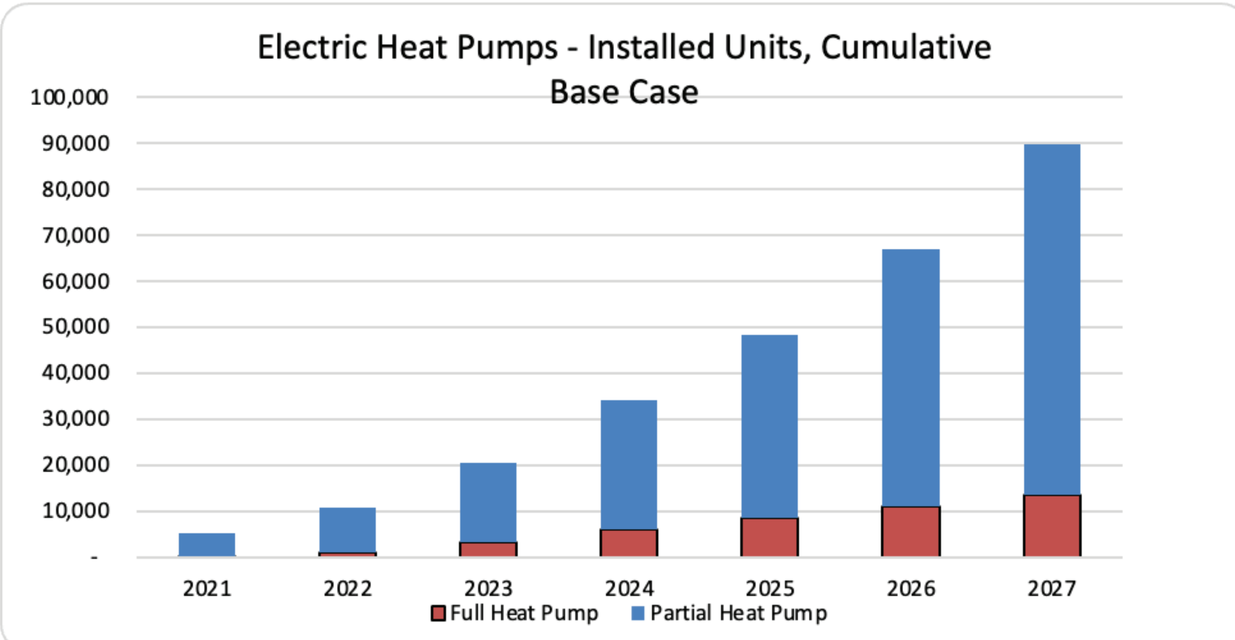

Figure 20: Number of electric heat pumps

Figure 14 and 16 above shows the expected <u>increase</u> to annual consumption by year. As of 2022, it is estimated that this technology will add MECO's annual energy by 25 GWh, or 0.1%. By 2027 it is expected that this may grow to 271 GWh, or 1.0%. Over the five-year planning horizon these technology raises annual growth (before any DERs) from 1.4% to 1.5% per year.

Appendices A1 and A2 show additional details for the DERs.

The DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. It is considered the most probable scenario at this time and is not intended to be inclusive of other activities including expanded renewables due to climate and

[5] Massachusetts Clean Energy and Climate Plan for 2025 and 2030, June 30, 2022

[6] The number is the total adoption but the legacy electric heat replacement (about 16%, based on American Community Survey) is excluded in the forecasting.

other regional discussions. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies as they become more likely.

1.5 Economic Scenarios

The discussion thus far has been confined to the base case economic scenario. The Company also developed parallel forecasts for both a higher and a lower economic scenario. The higher than base (or upside or Moody's S0) scenario2 is designed so that there is a 4% probability that the economy will perform better than in this scenario. It is based on the assumptions that Russian invasion of Ukraine resolves much faster than anticipated thereby the worries surrounding the global oil supply recede quickly and the supply-chain issues also diminish much more quickly reducing the shortage of affected goods and commodities. As a result, the inflation decelerates to Fed's target sooner than expected. New cases, hospitalizations, and deaths from COVID-19 recede faster than in the baseline. The economy returns to full employment in the fourth quarter of 2022 below the level assumed in the baseline with the real GDP higher than the baseline in 2023 and 2024. The lower than base (or downside or Moody's S4) scenario is designed so that there is a 96% probability that the economy will perform better than in this scenario. It assumes Russian invasion of Ukraine and supply-chain issue worsens causing more shortage of global oil supply and goods and commodities than assumed in the baseline putting upward pressure on inflation. New cases, hospitalizations, and deaths from COVID-19 rise significantly thus slowing the economic activity. It is also assumed that resurgence in COVID-19 aggravates the supply-chain problem further thereby raising the inflation. The economy falls into deep recession in the fourth quarter of 2022 and the unemployment rate continues to worsen.

Massachusetts Electric Company

Figure 21 shows the forecasts from using the base, high and low economic scenarios for MECO.

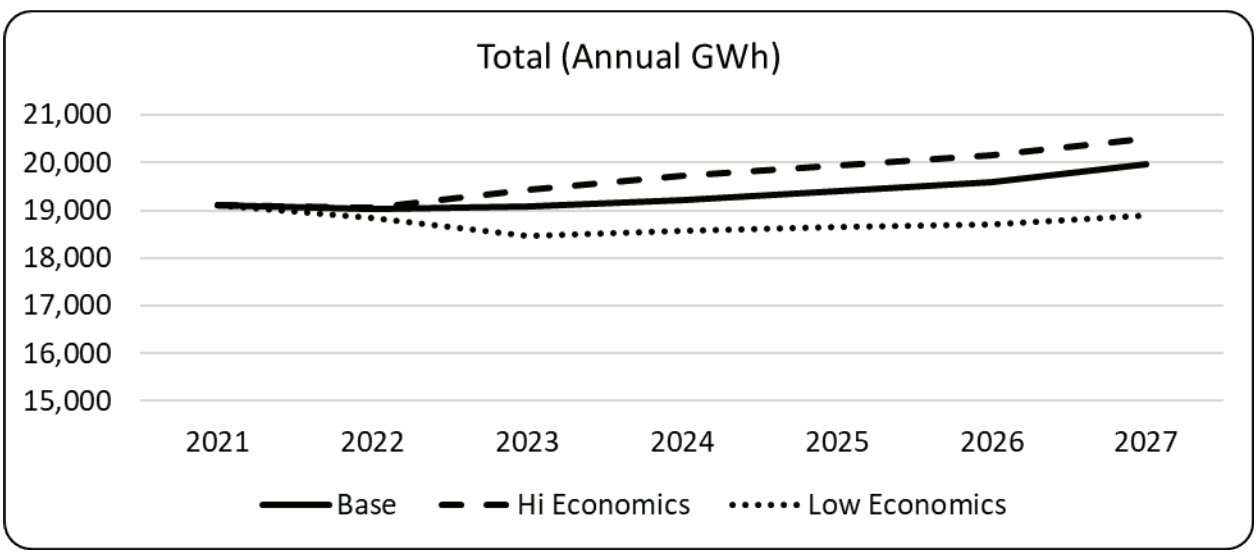

Figure 21: MECO Comparison of Forecasts using Base, High and Low Economic Scenarios

Table 3 shows a comparison of the values for the high and low economic scenarios versus the base case.

Table 3: Comparison of Forecasts from Base, High and Low Economic Scenarios

Calendar	Economics (base)	Economic (low)			Economic (high)		
Year	Forecast (GWh)	Forecast (GWh)	Delta (GWh)	Delta (%)	Forecast (GWh)	Delta (GWh)	Delta (%)
2022	19,022	18,852	(170)	-0.9%	19,055	34	0.2%
2023	19,080	18,453	(628)	-3.3%	19,419	338	1.8%
2024	19,218	18,559	(659)	-3.4%	19,715	496	2.6%
2025	19,415	18,659	(755)	-3.9%	19,954	539	2.8%
2026	19,602	18,702	(900)	-4.6%	20,150	548	2.8%
2027	19,957	18,900	(1,057)	-5.3%	20,500	543	2.7%

Both the forecast using Moody's baseline and the one using the high economic scenario expect growth every year through the planning horizon, with the high scenario predicting 2.7% higher by the end of the five-year planning horizon. The forecast from using the low economic scenario is considerably lower than the forecast using the baseline. It predict small decline in residential sector for later years in the forecast horizon and immediate decline in the commercial and industrial sectors. In the low economic scenario, for the next five years, the residential sector is expected to grow by 1.3% per year comparing to 1.8% using Moody's baseline scenario, the commercial sector is expected to decline by 0.7% per year comparing to a 0.8% growth per year using Moody's baseline scenario, and the industrial sector is expected to decline by 1.0% per year comparing to a smaller decline of 0.6% per year using Moody's baseline scenario.

Nantucket Electric Company

Figure 22 shows the forecasts from using the base, high and low economic scenarios for NANT.

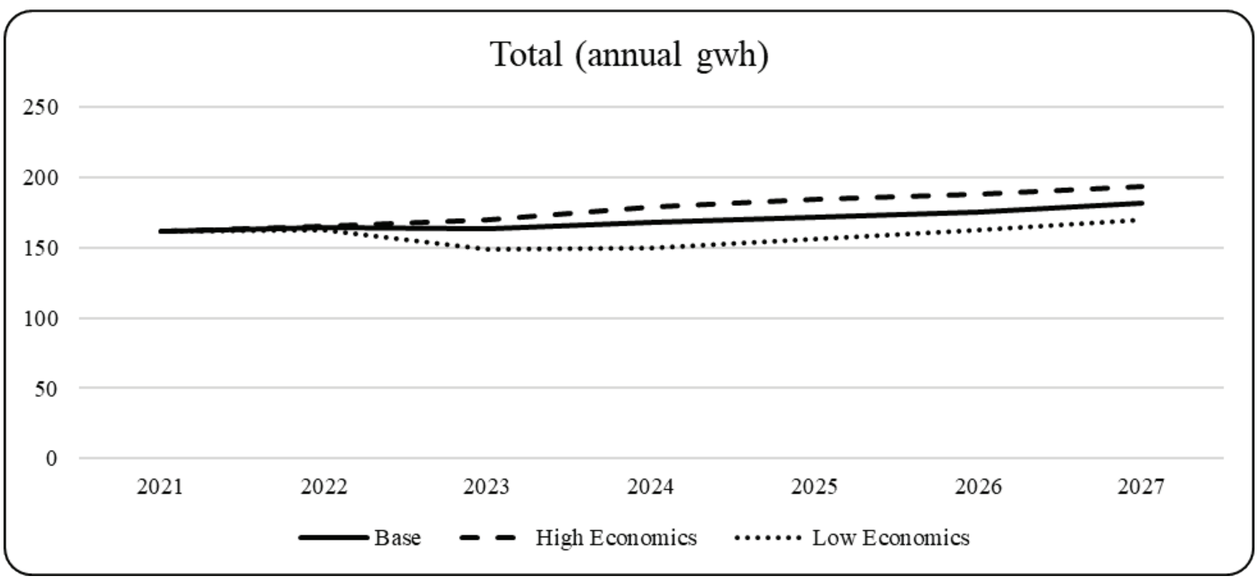

Figure 22: NANT Comparison of Forecasts using Base, High and Low Economic Scenarios

Table 4 shows a comparison of the values for the high and low economic scenarios versus the base case.

Table 4: Comparison of Forecasts from Base, High and Low Economic Scenarios

Calendar	Economic (Base)	Economic (low)			Economic (high)		
Year	Forecast (GWh)	Forecast (GWh)	Delta (GWh)	Delta (%)	Forecast (GWh)	Delta (GWh)	Delta (%)
2022	164.5	163.0	(1.5)	-0.9%	165.3	0.8	0.5%
2023	163.7	148.9	(14.8)	-9.0%	170.2	6.5	4.0%
2024	168.0	149.5	(18.5)	-11.0%	178.6	10.6	6.3%
2025	172.1	156.1	(16.0)	-9.3%	184.1	11.9	6.9%
2026	175.7	162.6	(13.2)	-7.5%	187.8	12.1	6.9%
2027	181.5	170.2	(11.3)	-6.2%	193.9	12.5	6.9%

1.6 Comparison to Previous Year's Forecast

Massachusetts Electric Company

Figure 23 shows a comparison of this year's forecast to last year's (vintage Fall 2021). It presents this comparison in two ways. The first in terms the "Gross" (or before the impacts of DERs) and the second is "Net" (after the impacts of DERs).

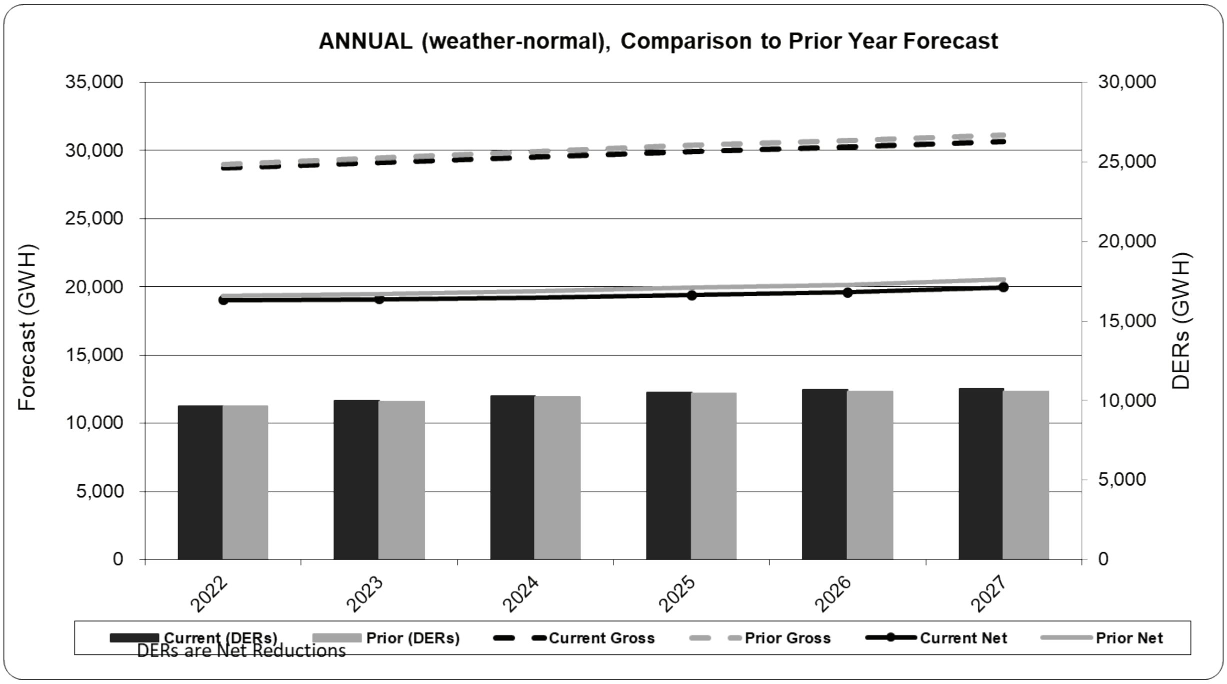

Figure 23: MECO Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

Table 5 contains the numbers supporting Figure 23.

Table 5: MECO Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

MECO ANNUAL GWh (weather-normal)										
	Current Forecast (Fall 2022)					Prior Forecast (Fall 2021)				
CALENDAR	Gross		Net		DER	Gross		Net		DER
YEAR	(GWh)	(% Grwth)	(GWh)	(% Grwth)	(GWh)	(GWh)	(% Grwth)	(GWh)	(% Grwth)	(GWh)
2022	28,688	1.4%	19,022	-0.5%	9,666	28,995	2.1%	19,355	0.7%	9,640
2023	29,097	1.4%	19,080	0.3%	10,016	29,472	1.6%	19,514	0.8%	9,958
2024	29,519	1.5%	19,218	0.7%	10,301	29,935	1.6%	19,695	0.9%	10,240
2025	29,936	1.4%	19,415	1.0%	10,522	30,370	1.5%	19,931	1.2%	10,439
2026	30,277	1.1%	19,602	1.0%	10,674	30,707	1.1%	20,167	1.2%	10,540
2027	30,698	1.4%	19,957	1.8%	10,742	31,130	1.4%	20,581	2.1%	10,549

As shown in the figure and the table, the 2022 release has a similar outlook as the 2021 release on the gross energy forecasts and DER impacts through the five-year forecast horizon.

Nantucket Electric Company

Figure 24 shows a comparison of this year's forecast to last year's (vintage Fall 2021). It presents this comparison in two ways. The first in terms the "Gross" (or before the impacts of DERs) and the second is "Net" (after the impacts of DERs).

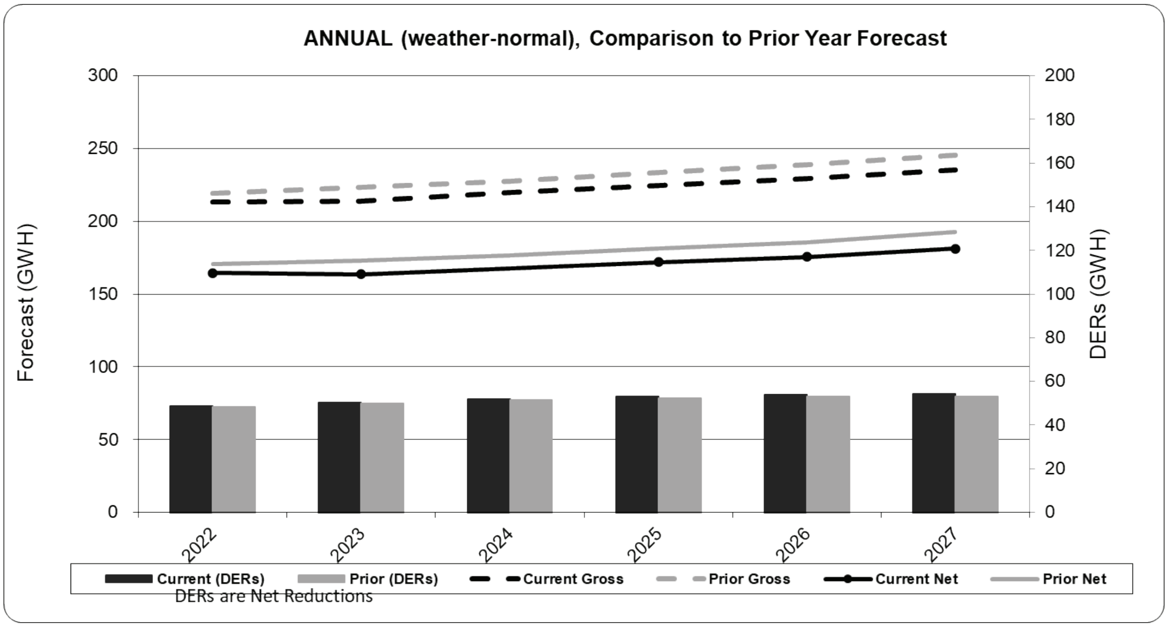

Figure 24: NANT Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

Table 6 contains the numbers supporting Figure 24.

Table 6: NANT Comparison of Forecasts and DERs, Current 2022 vs. Prior 2021 Vintages

As shown in the figure and the table, the 2022 release has a similar outlook on the gross energy forecasts and DER impacts through the forecast horizon.

2. Massachusetts Electric Company

2.1. Forecasted Fiscal Year Deliveries by Revenue Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		M		TOTAL	
2008	7,708.3		945.2		8,653.5		9,443.7		3,766.2		110.2		10.3		21,973.5	
2009	7,649.1	-0.8%	919.5	-2.7%	8,568.6	-1.0%	9,439.6	0.0%	3,703.1	-1.7%	110.2	0.0%	9.9	-4.2%	21,821.5	-0.7%
2010	7,737.6	1.2%	906.9	-1.4%	8,644.5	0.9%	9,257.1	-1.9%	3,394.8	-8.3%	109.0	-1.1%	9.5	-3.6%	21,405.4	-1.9%
2011	7,831.8	1.2%	903.4	-0.4%	8,735.2	1.0%	9,177.5	-0.9%	3,362.5	-1.0%	108.7	-0.2%	9.7	2.5%	21,384.0	-0.1%
2012	7,874.2	0.5%	895.5	-0.9%	8,769.7	0.4%	9,221.0	0.5%	3,268.8	-2.8%	108.4	-0.3%	9.0	-8.0%	21,368.0	-0.1%
2013	7,991.1	1.5%	895.4	0.0%	8,886.4	1.3%	9,218.6	0.0%	3,203.3	-2.0%	109.4	0.9%	9.3	3.5%	21,417.7	0.2%
2014	8,014.6	0.3%	898.6	0.4%	8,913.2	0.3%	9,141.9	-0.8%	3,140.8	-2.0%	106.6	-2.6%	9.6	3.3%	21,302.5	-0.5%
2015	7,737.7	-3.5%	872.1	-2.9%	8,609.8	-3.4%	9,095.6	-0.5%	3,145.9	0.2%	110.4	3.6%	8.6	-10.5%	20,961.8	-1.6%
2016	7,512.6	-2.9%	824.1	-5.5%	8,336.7	-3.2%	9,134.9	0.4%	3,080.5	-2.1%	107.8	-2.4%	6.7	-22.0%	20,659.8	-1.4%
2017	7,337.1	-2.3%	796.5	-3.3%	8,133.7	-2.4%	8,924.3	-2.3%	2,853.1	-7.4%	103.5	-4.0%	7.1	6.2%	20,014.5	-3.1%
2018	7,320.9	-0.2%	801.9	0.7%	8,122.8	-0.1%	8,896.3	-0.3%	2,776.6	-2.7%	99.6	-3.8%	6.4	-9.5%	19,895.2	-0.6%
2019	7,277.8	-0.6%	782.7	-2.4%	8,060.4	-0.8%	8,815.3	-0.9%	2,623.1	-5.5%	80.5	-19.2%	6.9	7.1%	19,579.3	-1.6%
2020	7,043.8	-3.2%	763.4	-2.5%	7,807.3	-3.1%	8,671.5	-1.6%	2,511.5	-4.3%	75.4	-6.3%	6.3	-9.0%	19,065.7	-2.6%
2021	7,686.1	9.1%	774.2	1.4%	8,460.3	8.4%	8,039.9	-7.3%	2,421.3	-3.6%	59.1	-21.6%	6.1	-2.0%	18,980.6	-0.4%
2022	7,380.0	-4.0%	763.3	-1.4%	8,143.3	-3.7%	8,330.9	3.6%	2,433.9	0.5%	56.0	-5.2%	6.0	-1.9%	18,964.1	-0.1%
2023	7,514.9	1.8%	739.6	-3.1%	8,254.4	1.4%	8,327.0	0.0%	2,458.1	1.0%	60.5	8.0%	6.0	-1.0%	19,100.1	0.7%
2024	7,511.8	0.0%	765.2	3.5%	8,277.1	0.3%	8,346.2	0.2%	2,427.5	-1.2%	64.2	6.1%	6.0	0.0%	19,114.9	0.1%
2025	7,649.2	1.8%	780.5	2.0%	8,429.7	1.8%	8,418.8	0.9%	2,401.3	-1.1%	63.6	-0.9%	6.0	0.0%	19,313.4	1.0%
2026	7,781.5	1.7%	796.5	2.0%	8,578.0	1.8%	8,483.6	0.8%	2,359.2	-1.8%	63.0	-0.9%	6.0	0.0%	19,483.8	0.9%
2027	7,951.9	2.2%	817.8	2.7%	8,769.7	2.2%	8,554.8	0.8%	2,312.2	-2.0%	62.4	-0.9%	6.0	0.0%	19,699.1	1.1%
2028	8,207.0	3.2%	847.2	3.6%	9,054.2	3.2%	8,666.8	1.3%	2,277.9	-1.5%	61.9	-0.9%	6.0	0.0%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.2%		-1.6%		-0.3%		-0.8%		-2.8%		-3.9%		-3.6%		-0.9%
prior 10 years		-0.6%		-1.9%		-0.7%		-1.0%		-2.6%		-5.8%		-4.3%		-1.1%
prior 5 years		0.5%		-1.6%		0.3%		-1.3%		-2.4%		-9.5%		-1.5%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.8%		2.8%		1.9%		0.8%		-1.5%		0.5%		0.0%		1.0%

2.2. Forecasted Fiscal Year Customer Counts by Revenue Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Revenue Class

CALENDAR YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	1,019,127		82,817		1,101,944		155,931		4,874		1,707		1,264,466	
2009	1,021,187	0.2%	82,613	-0.2%	1,103,800	0.2%	155,644	-0.2%	4,710	-3.4%	1,982	16.1%	1,266,135	0.1%
2010	1,029,838	0.8%	82,629	0.0%	1,112,467	0.8%	157,054	0.9%	4,667	-0.9%	2,405	21.3%	1,276,594	0.8%
2011	1,037,953	0.8%	82,814	0.2%	1,120,767	0.7%	158,282	0.8%	4,609	-1.2%	2,768	15.1%	1,286,428	0.8%
2012	1,041,268	0.3%	82,671	-0.2%	1,123,939	0.3%	159,381	0.7%	4,548	-1.3%	3,081	11.3%	1,290,950	0.4%
2013	1,045,146	0.4%	82,524	-0.2%	1,127,671	0.3%	160,180	0.5%	4,476	-1.6%	3,482	13.0%	1,295,811	0.4%
2014	1,048,667	0.3%	82,465	-0.1%	1,131,132	0.3%	160,839	0.4%	4,399	-1.7%	3,675	5.5%	1,300,042	0.3%
2015	1,053,420	0.5%	82,392	-0.1%	1,135,812	0.4%	161,858	0.6%	4,364	-0.8%	3,717	1.1%	1,305,757	0.4%
2016	1,062,394	0.9%	82,459	0.1%	1,144,853	0.8%	162,748	0.5%	4,312	-1.2%	3,582	-3.6%	1,315,504	0.7%
2017	1,057,399	-0.5%	81,653	-1.0%	1,139,052	-0.5%	162,694	0.0%	4,223	-2.1%	3,489	-2.6%	1,309,464	-0.5%
2018	1,066,349	0.8%	81,682	0.0%	1,148,032	0.8%	164,918	1.4%	4,157	-1.6%	3,476	-0.4%	1,320,582	0.8%
2019	1,072,691	0.6%	81,223	-0.6%	1,153,913	0.5%	165,915	0.6%	4,081	-1.8%	3,453	-0.7%	1,327,363	0.5%
2020	1,082,912	1.0%	81,247	0.0%	1,164,159	0.9%	167,092	0.7%	4,027	-1.3%	3,416	-1.1%	1,338,695	0.9%
2021	1,090,061	0.7%	80,206	-1.3%	1,170,267	0.5%	166,150	-0.6%	3,929	-2.4%	3,370	-1.3%	1,343,718	0.4%
2022	1,105,751	1.4%	80,214	0.0%	1,185,965	1.3%	165,673	-0.3%	3,831	-2.5%	3,340	-0.9%	1,358,810	1.1%
2023	1,107,975	0.2%	80,657	0.6%	1,188,632	0.2%	166,342	0.4%	3,864	0.9%	3,348	0.2%	1,362,185	0.2%
2024	1,105,217	-0.2%	80,747	0.1%	1,185,964	-0.2%	167,543	0.7%	4,112	6.4%	3,330	-0.5%	1,360,949	-0.1%
2025	1,108,753	0.3%	80,627	-0.1%	1,189,380	0.3%	168,061	0.3%	4,215	2.5%	3,304	-0.8%	1,364,960	0.3%
2026	1,112,254	0.3%	80,510	-0.1%	1,192,764	0.3%	168,568	0.3%	4,240	0.6%	3,276	-0.9%	1,368,848	0.3%
2027	1,115,010	0.2%	80,418	-0.1%	1,195,428	0.2%	168,967	0.2%	4,232	-0.2%	3,247	-0.9%	1,371,875	0.2%
2028	1,117,274	0.2%	80,342	-0.1%	1,197,616	0.2%	169,296	0.2%	4,214	-0.4%	3,109	-4.2%	1,374,346	0.2%

Annual Growth Rates:	Res. Non-Heating	Elec Heating	Res. Total	Commercial	Industrial	StreetLighting & Other	Total
prior 15 years	0.6%	-0.2%	0.5%	0.4%	-1.5%	4.6%	0.5%
prior 10 years	0.6%	-0.2%	0.5%	0.4%	-1.5%	-0.4%	0.5%
prior 5 years	0.8%	-0.3%	0.7%	0.2%	-1.5%	-0.7%	0.6%
BASE YEAR:	**2023**						
next 5 years	0.2%	-0.1%	0.2%	0.4%	1.7%	-1.5%	0.2%

2.3. Forecasted Fiscal Year Deliveries by Rate Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Rate Code																
After Energy Efficiency, Solar and Electric Vehicle Impacts																
FISCAL YEAR	**RI**		**R2**		**R4**		**G1**		**G2**		**G3**		**SL**		**TOTAL**	
2008	8,019.4		659.9		14.4		2,221.2		2,893.2		8,027.6		137.8		21,973.5	
2009	7,877.6	-1.8%	716.5	8.6%	13.8	-4.3%	2,202.2	-0.9%	2,876.5	-0.6%	7,997.9	-0.4%	137.0	-0.6%	21,821.5	-0.7%
2010	7,820.2	-0.7%	849.6	18.6%	13.4	-3.1%	2,128.9	-3.3%	2,792.5	-2.9%	7,666.1	-4.1%	134.7	-1.7%	21,405.4	-1.9%
2011	7,867.4	0.6%	895.3	5.4%	12.7	-5.0%	2,151.1	1.0%	2,784.1	-0.3%	7,541.7	-1.6%	131.7	-2.3%	21,384.0	-0.1%
2012	7,813.4	-0.7%	983.1	9.8%	12.4	-2.2%	2,143.1	-0.4%	2,801.3	0.6%	7,483.3	-0.8%	131.4	-0.2%	21,368.0	-0.1%
2013	7,836.0	0.3%	1,075.8	9.4%	11.9	-3.9%	2,176.5	1.6%	2,801.7	0.0%	7,384.6	-1.3%	131.1	-0.3%	21,417.7	0.2%
2014	7,800.6	-0.5%	1,137.4	5.7%	11.9	-0.6%	2,167.2	-0.4%	2,794.9	-0.2%	7,263.9	-1.6%	126.7	-3.3%	21,302.5	-0.5%
2015	7,474.4	-4.2%	1,160.5	2.0%	11.4	-4.0%	2,156.4	-0.5%	2,806.1	0.4%	7,222.2	-0.6%	130.9	3.3%	20,961.8	-1.6%
2016	7,169.6	-4.1%	1,191.7	2.7%	10.3	-9.5%	2,144.3	-0.6%	2,800.2	-0.2%	7,214.2	-0.1%	129.6	-1.0%	20,659.8	-1.4%
2017	7,114.8	-0.8%	1,042.4	-12.5%	9.7	-5.9%	2,113.9	-1.4%	2,719.2	-2.9%	6,890.9	-4.5%	123.6	-4.6%	20,014.5	-3.1%
2018	7,165.4	0.7%	979.4	-6.0%	9.5	-1.5%	2,128.9	0.7%	2,701.6	-0.6%	6,789.9	-1.5%	120.6	-2.4%	19,895.2	-0.6%
2019	7,120.5	-0.6%	962.0	-1.8%	10.5	9.9%	2,155.4	1.2%	2,693.4	-0.3%	6,536.3	-3.7%	101.2	-16.1%	19,579.3	-1.6%
2020	6,973.9	-2.1%	857.7	-10.8%	4.6	-56.5%	2,086.1	-3.2%	2,633.9	-2.2%	6,414.6	-1.9%	95.0	-6.2%	19,065.7	-2.6%
2021	7,523.9	7.9%	956.4	11.5%	-	-100.0%	1,937.7	-7.1%	2,435.5	-7.5%	6,049.2	-5.7%	77.9	-18.0%	18,980.6	-0.4%
2022	7,207.3	-4.2%	953.7	-0.3%	-		2,029.7	4.7%	2,519.1	3.4%	6,180.1	2.2%	74.2	-4.7%	18,964.1	-0.1%
2023	7,287.0	1.1%	985.1	3.3%	-		2,044.4	0.7%	2,444.6	-3.0%	6,262.6	1.3%	76.3	2.7%	19,100.1	0.7%
2024	7,310.2	0.3%	985.6	0.1%	-		2,052.4	0.4%	2,441.8	-0.1%	6,243.2	-0.3%	81.8	7.3%	19,114.9	0.1%
2025	7,444.6	1.8%	1,003.8	1.8%	-		2,069.0	0.8%	2,460.5	0.8%	6,254.0	0.2%	81.4	-0.5%	19,313.4	1.0%
2026	7,575.1	1.8%	1,021.5	1.8%	-		2,083.4	0.7%	2,476.3	0.6%	6,246.4	-0.1%	81.0	-0.5%	19,483.8	0.9%
2027	7,743.7	2.2%	1,044.4	2.2%	-		2,099.3	0.8%	2,493.6	0.7%	6,237.5	-0.1%	80.7	-0.5%	19,699.1	1.1%
2028	7,994.0	3.2%	1,078.3	3.3%	-		2,125.4	1.2%	2,522.8	1.2%	6,259.8	0.4%	80.4	-0.3%	20,060.8	1.8%
Annual Growth Rates:																
prior 15 years		-0.6%		2.7%		-100.0%		-0.6%		-1.1%		-1.6%		-3.9%		-0.9%
prior 10 years		-0.7%		-0.9%		-100.0%		-0.6%		-1.4%		-1.6%		-5.3%		-1.1%
prior 5 years		0.3%		0.1%		-100.0%		-0.8%		-2.0%		-1.6%		-8.8%		-0.8%
BASE YEAR:		**2023**														
next 5 years		1.9%		1.8%				0.8%		0.6%		0.0%		1.1%		1.0%

2.4. Forecasted Fiscal Year Customer Counts by Rate Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Rate Code

FISCAL YEAR	RI		R2		R4		G1		G2		G3		SL		TOTAL	
2008	1,004,319		98,164		213		144,578		12,400		3,263		1,530		1,264,466	
2009	998,210	-0.6%	106,031	8.0%	203	-4.4%	144,239	-0.2%	12,408	0.1%	3,270	0.2%	1,774	16.0%	1,266,135	0.1%
2010	990,041	-0.8%	122,789	15.8%	200	-1.6%	145,486	0.9%	12,647	1.9%	3,243	-0.8%	2,186	23.3%	1,276,594	0.8%
2011	991,884	0.2%	129,029	5.1%	211	5.4%	145,581	0.1%	13,731	8.6%	3,467	6.9%	2,525	15.5%	1,286,428	0.8%
2012	986,245	-0.6%	137,655	6.7%	195	-7.8%	148,423	2.0%	12,399	-9.7%	3,199	-7.7%	2,834	12.2%	1,290,950	0.4%
2013	980,792	-0.6%	146,624	6.5%	194	-0.4%	149,337	0.6%	12,441	0.3%	3,190	-0.3%	3,233	14.1%	1,295,811	0.4%
2014	978,363	-0.2%	152,401	3.9%	189	-2.6%	150,002	0.4%	12,477	0.3%	3,186	-0.1%	3,424	5.9%	1,300,042	0.3%
2015	976,038	-0.2%	159,200	4.5%	192	1.6%	151,163	0.8%	12,493	0.1%	3,202	0.5%	3,469	1.3%	1,305,757	0.4%
2016	975,802	0.0%	168,402	5.8%	175	-8.8%	152,154	0.7%	12,447	-0.4%	3,182	-0.6%	3,342	-3.7%	1,315,504	0.7%
2017	988,309	1.3%	150,109	-10.9%	160	-8.3%	152,211	0.0%	12,278	-1.4%	3,143	-1.2%	3,253	-2.7%	1,309,464	-0.5%
2018	1,005,161	1.7%	142,111	-5.3%	147	-8.4%	154,562	1.5%	12,230	-0.4%	3,130	-0.4%	3,241	-0.4%	1,320,582	0.8%
2019	1,013,979	0.9%	138,949	-2.2%	134	-8.6%	155,602	0.7%	12,349	1.0%	3,136	0.2%	3,215	-0.8%	1,327,363	0.5%
2020	1,032,465	1.8%	130,499	-6.1%	85	-36.7%	156,894	0.8%	12,403	0.4%	3,165	0.9%	3,184	-0.9%	1,338,695	0.9%
2021	1,032,956	0.0%	135,777	4.0%	-	-100.0%	156,546	-0.2%	12,168	-1.9%	3,151	-0.4%	3,121	-2.0%	1,343,718	0.4%
2022	1,045,005	1.2%	139,266	2.6%	-		156,464	-0.1%	11,898	-2.2%	3,088	-2.0%	3,090	-1.0%	1,358,810	1.1%
2023	1,044,365	-0.1%	142,465	2.3%	-		157,292	0.5%	11,840	-0.5%	3,125	1.2%	3,097	0.2%	1,362,185	0.2%
2024	1,043,380	-0.1%	140,867	-1.1%	-		158,398	0.7%	12,043	1.7%	3,180	1.8%	3,081	-0.5%	1,360,949	-0.1%
2025	1,046,391	0.3%	141,267	0.3%	-		158,942	0.3%	12,096	0.4%	3,208	0.9%	3,056	-0.8%	1,364,960	0.3%
2026	1,049,373	0.3%	141,663	0.3%	-		159,428	0.3%	12,135	0.3%	3,220	0.4%	3,029	-0.9%	1,368,848	0.3%
2027	1,051,721	0.2%	141,976	0.2%	-		159,793	0.2%	12,161	0.2%	3,224	0.1%	3,001	-0.9%	1,371,875	0.2%
2028	1,053,649	0.2%	142,232	0.2%	-		160,085	0.2%	12,179	0.2%	3,225	0.0%	2,975	-0.9%	1,374,346	0.2%
Annual Growth Rates:																
prior 15 years		0.3%		2.5%		-100.0%		0.6%		-0.3%		-0.3%		4.8%		0.5%
prior 10 years		0.6%		-0.3%		-100.0%		0.5%		-0.5%		-0.2%		-0.4%		0.5%
prior 5 years		0.8%		0.0%		-100.0%		0.4%		-0.6%		0.0%		-0.9%		0.6%
BASE YEAR:		**2023**														
next 5 years		0.2%		0.0%				0.4%		0.6%		0.6%		-0.8%		0.2%

3. Nantucket Electric Company

3.1. Forecasted Fiscal Year Deliveries by Revenue Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class

After Energy Efficiency, Solarr, Electric Vehicle, and Electric Hear Pump Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	93.3		1.9		95.3		49.4		0.8		0.3		145.8	
2009	92.1	-1.3%	1.7	-9.8%	93.8	-1.5%	49.1	-0.6%	0.9	9.2%	0.3	8.1%	144.1	-1.1%
2010	92.1	0.0%	1.7	-1.7%	93.8	-0.1%	50.7	3.2%	1.0	4.3%	0.3	-1.3%	145.7	1.1%
2011	88.1	-4.3%	1.5	-14.6%	89.6	-4.5%	48.8	-3.8%	1.0	6.2%	0.3	-1.7%	139.6	-4.1%
2012	91.6	3.9%	1.5	3.5%	93.1	3.9%	50.1	2.7%	1.0	1.9%	0.3	0.2%	144.5	3.5%
2013	93.5	2.0%	1.5	-0.1%	95.0	2.0%	49.5	-1.2%	1.0	-2.5%	0.3	-0.3%	145.7	0.8%
2014	101.7	8.8%	1.7	10.7%	103.4	8.8%	52.2	5.6%	1.0	-6.1%	0.3	1.1%	156.8	7.6%
2015	105.4	3.6%	1.7	1.5%	107.1	3.6%	54.2	3.9%	0.9	-1.6%	0.3	-0.9%	162.5	3.7%
2016	98.4	-6.6%	1.6	-8.3%	100.0	-6.6%	50.6	-6.7%	1.0	10.6%	0.3	-0.1%	151.9	-6.5%
2017	104.3	5.9%	1.6	1.9%	105.8	5.9%	51.2	1.1%	1.0	-7.8%	0.3	0.1%	158.2	4.2%
2018	111.4	6.8%	1.7	9.1%	113.1	6.9%	59.8	17.0%	0.7	-24.9%	0.3	0.4%	173.9	9.9%
2019	111.1	-0.3%	1.7	-3.9%	112.8	-0.3%	57.4	-4.1%	0.7	-3.5%	0.3	1.0%	171.1	-1.6%
2020	112.5	1.3%	1.6	-0.9%	114.2	1.2%	53.9	-6.0%	0.6	-7.6%	0.3	-1.2%	169.0	-1.2%
2021	118.7	5.5%	1.7	2.0%	120.4	5.5%	53.7	-0.5%	0.6	-9.0%	0.3	-0.3%	174.9	3.5%
2022	110.1	-7.3%	1.5	-8.6%	111.6	-7.3%	50.6	-5.8%	0.7	18.9%	0.3	-0.6%	163.1	-6.8%
2023	108.1	-1.8%	1.4	-6.8%	109.6	-1.8%	48.4	-4.4%	0.8	12.7%	0.2	-8.0%	158.9	-2.6%
2024	111.5	3.1%	1.4	0.8%	113.0	3.1%	51.1	5.7%	0.7	-5.0%	0.3	9.3%	165.1	3.9%
2025	114.5	2.7%	1.5	4.6%	116.1	2.7%	52.1	2.0%	0.7	-2.0%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	4.0%	119.0	2.5%	53.1	1.8%	0.7	-1.9%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	3.0%	121.8	2.4%	54.0	1.8%	0.7	-1.8%	0.3	0.0%	176.8	2.2%
2028	124.4	3.5%	1.7	4.1%	126.1	3.5%	55.5	2.7%	0.7	-1.7%	0.3	0.0%	182.6	3.3%

Annual Growth Rates:	Non-Heating	Elec Heating	Residential Total	Commercial	Industrial	StreetLighting & Other	Total
prior 15 years	1.0%	-2.0%	0.9%	-0.1%	-0.5%	-0.3%	0.6%
prior 10 years	1.5%	-0.5%	1.4%	-0.2%	-2.6%	-0.9%	0.9%
prior 5 years	-0.6%	-3.7%	-0.6%	-4.2%	1.7%	-1.9%	-1.8%
BASE YEAR:	**2023**						
next 5 years	2.9%	3.3%	2.9%	2.8%	-2.5%	1.8%	2.8%

3.2. Forecasted Fiscal Year Customer Counts by Revenue Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Revenue Class														
CALENDAR YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2008	10,784		298		11,082		1,348		4		7		12,442	
2009	10,926	1.3%	285	-4.6%	11,210	1.2%	1,402	4.0%	4	-10.4%	6	-11.9%	12,622	1.4%
2010	10,998	0.7%	280	-1.7%	11,277	0.6%	1,437	2.5%	4	-2.3%	6	-2.7%	12,724	0.8%
2011	11,032	0.3%	275	-1.8%	11,307	0.3%	1,456	1.3%	3	-14.3%	6	0.0%	12,772	0.4%
2012	11,085	0.5%	265	-3.3%	11,350	0.4%	1,465	0.6%	4	27.8%	6	0.0%	12,825	0.4%
2013	11,155	0.6%	256	-3.5%	11,411	0.5%	1,475	0.7%	4	-2.2%	6	0.0%	12,896	0.6%
2014	11,203	0.4%	250	-2.4%	11,453	0.4%	1,515	2.7%	4	-4.4%	6	0.0%	12,977	0.6%
2015	11,293	0.8%	239	-4.2%	11,532	0.7%	1,549	2.3%	4	2.3%	6	0.0%	13,091	0.9%
2016	11,370	0.7%	235	-1.7%	11,605	0.6%	1,575	1.7%	4	9.1%	6	0.0%	13,190	0.8%
2017	11,509	1.2%	228	-3.2%	11,737	1.1%	1,606	1.9%	4	-4.2%	6	0.0%	13,353	1.2%
2018	11,630	1.0%	180	-20.8%	11,810	0.6%	1,624	1.1%	4	4.3%	6	0.0%	13,444	0.7%
2019	11,787	1.3%	177	-1.7%	11,964	1.3%	1,639	0.9%	4	0.0%	6	0.0%	13,613	1.3%
2020	11,769	-0.2%	174	-2.1%	11,942	-0.2%	1,622	-1.0%	4	0.0%	6	0.0%	13,574	-0.3%
2021	12,048	2.4%	174	0.4%	12,223	2.3%	1,676	3.3%	4	-2.1%	6	0.0%	13,909	2.5%
2022	12,166	1.0%	172	-1.1%	12,338	0.9%	1,713	2.2%	4	2.1%	6	0.0%	14,061	1.1%
2023	12,286	1.0%	170	-1.0%	12,456	1.0%	1,711	-0.1%	4	0.0%	6	0.0%	14,178	0.8%
2024	12,307	0.2%	169	-1.1%	12,476	0.2%	1,732	1.2%	4	0.0%	6	0.0%	14,218	0.3%
2025	12,350	0.4%	167	-0.9%	12,517	0.3%	1,754	1.2%	4	0.0%	6	0.0%	14,281	0.4%
2026	12,423	0.6%	166	-1.0%	12,589	0.6%	1,777	1.3%	4	0.0%	6	0.0%	14,375	0.7%
2027	12,512	0.7%	164	-1.0%	12,676	0.7%	1,801	1.4%	4	0.0%	6	0.0%	14,486	0.8%
2028	12,607	0.8%	162	-1.0%	12,770	0.7%	1,826	1.4%	4	0.0%	6	0.0%	14,605	0.8%
Annual Growth Rates:														
prior 15 years		0.9%		-3.7%		0.8%		1.6%		0.0%		-1.0%		0.9%
prior 10 years		1.0%		-4.0%		0.9%		1.5%		0.6%		0.0%		1.0%
prior 5 years		1.1%		-1.1%		1.1%		1.1%		0.0%		0.0%		1.1%
BASE YEAR:		**2023**												
next 5 years		0.5%		-1.0%		0.5%		1.3%		0.0%		0.0%		0.6%

3.3. Forecasted Fiscal Year Deliveries by Rate Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals: Actuals; Projections: Weather-Normal) by Rate Code
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RI		R2		G1		G2		G3		SL		TOTAL	
2008	92.9		1.0		24.6		16.4		8.3		0.3		143.6	
2009	93.1	0.1%	1.1	10.6%	24.4	-0.9%	16.6	0.8%	8.5	2.5%	0.3	8.4%	143.9	0.3%
2010	88.9	-4.5%	1.3	26.1%	24.6	0.8%	16.5	-0.7%	8.6	1.3%	0.3	-1.2%	140.2	-2.6%
2011	92.7	4.3%	1.5	8.6%	25.2	2.5%	15.9	-3.3%	9.8	13.7%	0.3	-1.7%	145.4	3.7%
2012	90.3	-2.6%	1.8	22.7%	22.9	-9.2%	16.1	0.8%	12.0	22.2%	0.3	0.2%	143.3	-1.4%
2013	96.4	6.8%	1.9	5.0%	23.9	4.2%	16.5	2.6%	11.2	-6.6%	0.3	-0.3%	150.1	4.8%
2014	101.7	5.5%	2.0	6.3%	24.0	0.4%	17.6	6.6%	11.0	-2.1%	0.3	1.1%	156.5	4.2%
2015	101.2	-0.5%	2.0	1.3%	24.1	0.5%	16.8	-4.2%	12.1	10.8%	0.3	-0.9%	156.6	0.1%
2016	100.9	-0.3%	2.0	-2.9%	23.6	-1.9%	16.7	-0.7%	12.8	5.3%	0.3	-0.1%	156.3	-0.2%
2017	104.6	3.6%	2.0	2.6%	22.8	-3.7%	16.8	0.8%	12.9	0.8%	0.3	0.1%	159.3	2.0%
2018	106.7	2.0%	1.9	-5.0%	23.8	4.7%	17.8	5.9%	16.8	30.6%	0.3	0.4%	167.4	5.0%
2019	113.5	6.4%	1.6	-18.9%	25.6	7.5%	18.8	5.1%	13.9	-17.4%	0.3	1.0%	173.7	3.7%
2020	111.5	-1.8%	1.2	-24.2%	25.1	-1.9%	18.2	-3.2%	11.0	-21.1%	0.3	-1.2%	167.2	-3.7%
2021	120.5	8.1%	1.4	19.6%	22.7	-9.7%	15.9	-12.2%	16.6	51.3%	0.3	-0.3%	177.4	6.1%
2022	121.1	0.5%	1.6	10.3%	25.1	10.8%	17.5	9.9%	13.5	-18.4%	0.3	-0.6%	179.1	1.0%
2023	114.2	-5.7%	1.3	-13.9%	22.8	-9.2%	16.4	-6.6%	12.4	-8.4%	0.2	-8.1%	167.4	-6.5%
2024	111.5	-2.4%	1.5	11.5%	23.1	1.1%	16.2	-0.9%	12.5	0.9%	0.3	9.3%	165.1	-1.4%
2025	114.6	2.7%	1.5	2.7%	23.5	2.0%	16.5	2.0%	12.7	1.8%	0.3	0.0%	169.2	2.5%
2026	117.4	2.5%	1.6	2.5%	24.0	1.8%	16.8	1.8%	13.0	1.7%	0.3	0.0%	173.0	2.3%
2027	120.2	2.4%	1.6	2.4%	24.4	1.8%	17.1	1.8%	13.2	1.6%	0.3	0.0%	176.8	2.2%
2028	124.5	3.5%	1.7	3.5%	25.1	2.7%	17.6	2.7%	13.5	2.5%	0.3	0.0%	182.6	3.3%

Annual Growth Rates:	RI	R2	G1	G2	G3	SL	TOTAL
prior 15 years	1.4%	2.2%	-0.5%	0.0%	2.7%	-0.3%	1.0%
prior 10 years	1.7%	-3.3%	-0.4%	-0.1%	1.0%	-0.9%	1.1%
prior 5 years	1.4%	-6.9%	-0.8%	-1.7%	-5.9%	-1.9%	0.0%
BASE YEAR:	**2023**						
next 5 years	1.7%	4.5%	1.9%	1.5%	1.7%	1.8%	1.8%

3.4. Forecasted Fiscal Year Customer Counts by Rate Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Rate Code														
FISCAL YEAR	RI		R2		G1		G2		G3		SL		TOTAL	
2008	10,969		111		1,292		57		6		6		12,442	
2009	11,089	1.1%	118	6.8%	1,342	3.9%	59	3.6%	6	-1.3%	7	19.5%	12,622	1.4%
2010	11,113	0.2%	165	39.3%	1,371	2.2%	62	4.0%	6	0.5%	7	3.3%	12,724	0.8%
2011	11,141	0.3%	177	7.4%	1,373	0.1%	67	8.2%	7	20.3%	7	-0.6%	12,772	0.4%
2012	11,154	0.1%	212	19.8%	1,384	0.8%	59	-11.2%	8	13.6%	7	0.6%	12,825	0.4%
2013	11,209	0.5%	211	-0.5%	1,397	0.9%	64	7.3%	9	5.3%	7	0.0%	12,896	0.6%
2014	11,252	0.4%	209	-0.9%	1,436	2.8%	65	1.5%	8	-2.3%	7	0.0%	12,977	0.6%
2015	11,338	0.8%	217	3.6%	1,454	1.3%	66	1.5%	10	14.6%	7	0.0%	13,091	0.9%
2016	11,400	0.5%	220	1.3%	1,486	2.2%	68	3.5%	10	3.2%	7	0.0%	13,190	0.8%
2017	11,534	1.2%	214	-2.6%	1,514	1.9%	73	8.1%	11	8.5%	7	-0.4%	13,353	1.2%
2018	11,617	0.7%	203	-5.0%	1,532	1.2%	74	0.5%	11	1.5%	7	0.5%	13,444	0.7%
2019	11,802	1.6%	158	-22.1%	1,555	1.5%	77	4.4%	13	18.0%	7	0.0%	13,613	1.3%
2020	11,803	0.0%	138	-12.7%	1,534	-1.3%	79	2.6%	12	-4.2%	7	-0.2%	13,574	-0.3%
2021	12,070	2.3%	149	7.8%	1,589	3.6%	79	-0.4%	14	13.2%	7	0.2%	13,909	2.5%
2022	12,171	0.8%	170	14.1%	1,622	2.0%	80	1.6%	12	-17.6%	7	0.0%	14,061	1.1%
2023	12,290	1.0%	162	-5.0%	1,630	0.5%	78	-2.8%	11	-6.7%	7	0.1%	14,178	0.8%
2024	12,310	0.2%	165	2.2%	1,646	1.0%	80	2.4%	11	2.9%	7	0.1%	14,218	0.3%
2025	12,351	0.3%	166	0.3%	1,666	1.2%	81	1.2%	11	1.1%	7	0.2%	14,281	0.4%
2026	12,422	0.6%	167	0.6%	1,687	1.3%	82	1.3%	11	1.2%	7	0.2%	14,375	0.7%
2027	12,508	0.7%	168	0.7%	1,709	1.3%	83	1.3%	11	1.2%	7	0.2%	14,486	0.8%
2028	12,601	0.7%	169	0.7%	1,733	1.4%	84	1.4%	12	1.3%	7	0.2%	14,605	0.8%

Appendices

APPENDIX A1: DERs - Massachusetts Electric

MECO TOTAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before DER impacts)	DELIVERIES (50/50): Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	DER IMPACTS: EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	23,160	22,113	23,159	23,160	23,160	**22,112**	(1,047)	(1)	0	0	(1,048)
2008	23,133	21,845	23,131	23,133	23,133	**21,843**	(1,288)	(1)	0	0	(1,289)
2009	22,983	21,424	22,980	22,983	22,983	**21,422**	(1,558)	(3)	0	0	(1,561)
2010	23,278	21,408	23,273	23,278	23,278	**21,403**	(1,870)	(5)	0	0	(1,875)
2011	23,585	21,379	23,576	23,585	23,585	**21,371**	(2,205)	(8)	0	0	(2,214)
2012	24,098	21,424	24,080	24,099	24,098	**21,407**	(2,674)	(18)	1	0	(2,691)
2013	24,567	21,352	24,527	24,569	24,567	**21,315**	(3,215)	(40)	2	0	(3,252)
2014	24,990	21,186	24,906	24,995	24,990	**21,106**	(3,805)	(84)	4	0	(3,884)
2015	25,396	20,940	25,214	25,402	25,396	**20,765**	(4,456)	(182)	7	0	(4,631)
2016	25,533	20,403	25,212	25,542	25,533	**20,092**	(5,129)	(321)	9	0	(5,441)
2017	26,130	20,309	25,700	26,143	26,130	**19,892**	(5,820)	(430)	13	0	(6,238)
2018	26,718	20,167	26,212	26,738	26,718	**19,682**	(6,551)	(506)	21	0	(7,036)
2019	26,916	19,676	26,336	26,946	26,918	**19,127**	(7,241)	(580)	30	1	(7,789)
2020	27,477	19,586	26,808	27,516	27,482	**18,962**	(7,891)	(669)	39	6	(8,515)
2021	28,300	19,825	27,529	28,354	28,312	**19,120**	(8,475)	(771)	54	12	(9,181)
2022	28,688	19,805	27,791	28,776	28,713	**19,022**	(8,882)	(897)	89	25	(9,666)
2023	29,097	19,916	28,063	29,244	29,149	**19,080**	(9,181)	(1,034)	147	52	(10,016)
2024	29,519	20,062	28,348	29,752	29,613	**19,218**	(9,457)	(1,171)	233	94	(10,301)
2025	29,936	20,220	28,636	30,286	30,081	**19,415**	(9,716)	(1,300)	350	144	(10,522)
2026	30,277	20,322	28,848	30,785	30,478	**19,602**	(9,955)	(1,429)	508	201	(10,674)
2027	30,698	20,522	29,140	31,421	30,969	**19,957**	(10,177)	(1,559)	722	271	(10,742)

Annual Growth Rates:											
prior 15 years	1.4%	-0.7%	1.2%	1.5%	1.4%	**-1.0%**	-2.2%	-0.2%	0.0%	0.0%	-2.4%
prior 10 years	1.8%	-0.8%	1.4%	1.8%	1.8%	**-1.2%**	-2.5%	-0.3%	0.0%	0.0%	-2.9%
prior 5 years	1.9%	-0.5%	1.6%	1.9%	1.9%	**-0.9%**	-2.4%	-0.3%	0.1%	0.0%	-2.8%
BASE YEAR: 2022											
next 5 years	1.4%	0.7%	1.0%	1.8%	1.5%	**1.0%**	-0.7%	-0.4%	0.4%	0.2%	-0.4%

MECO RESIDENTIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before DER impacts)	DELIVERIES (50/50): Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	DER IMPACTS: EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	9,232	8,659	9,231	9,232	9,232	**8,658**	(573)	(1)	0	0	(574)
2008	9,329	8,621	9,328	9,329	9,329	**8,620**	(708)	(1)	0	0	(709)
2009	9,449	8,596	9,447	9,449	9,449	**8,594**	(853)	(3)	0	0	(856)
2010	9,717	8,722	9,713	9,717	9,717	**8,718**	(995)	(4)	0	0	(1,000)
2011	9,891	8,769	9,885	9,891	9,891	**8,763**	(1,122)	(7)	0	0	(1,129)
2012	10,167	8,866	10,154	10,168	10,167	**8,854**	(1,301)	(13)	1	0	(1,314)
2013	10,477	8,934	10,450	10,479	10,477	**8,910**	(1,542)	(27)	2	0	(1,567)
2014	10,602	8,756	10,541	10,605	10,602	**8,699**	(1,845)	(61)	4	0	(1,902)
2015	10,735	8,600	10,585	10,740	10,735	**8,456**	(2,135)	(150)	5	0	(2,279)
2016	10,849	8,410	10,572	10,856	10,849	**8,139**	(2,439)	(278)	7	0	(2,710)
2017	11,277	8,461	10,907	11,288	11,277	**8,103**	(2,815)	(370)	11	0	(3,174)
2018	11,774	8,530	11,343	11,792	11,774	**8,116**	(3,244)	(431)	17	0	(3,658)
2019	11,921	8,292	11,424	11,946	11,922	**7,822**	(3,628)	(497)	25	1	(4,099)
2020	12,865	8,859	12,292	12,897	12,870	**8,324**	(4,006)	(572)	33	6	(4,540)
2021	13,099	8,795	12,441	13,143	13,111	**8,194**	(4,303)	(658)	45	12	(4,905)
2022	13,331	8,898	12,561	13,404	13,355	**8,226**	(4,433)	(770)	73	24	(5,105)
2023	13,477	8,972	12,580	13,595	13,525	**8,242**	(4,505)	(896)	119	48	(5,234)
2024	13,692	9,117	12,669	13,875	13,777	**8,363**	(4,575)	(1,022)	184	85	(5,328)
2025	13,904	9,263	12,763	14,173	14,033	**8,521**	(4,641)	(1,141)	270	130	(5,383)
2026	14,082	9,385	12,822	14,469	14,263	**8,692**	(4,697)	(1,260)	386	180	(5,390)
2027	14,304	9,560	12,924	14,848	14,547	**8,968**	(4,744)	(1,380)	545	244	(5,336)

Annual Growth Rates:											
prior 15 years	2.5%	0.2%	2.1%	2.5%	2.5%	**-0.3%**	-2.3%	-0.4%	0.0%	0.0%	-2.8%
prior 10 years	2.7%	0.0%	2.1%	2.8%	2.8%	**-0.7%**	-2.7%	-0.6%	0.1%	0.0%	-3.5%
prior 5 years	3.4%	1.0%	2.9%	3.5%	3.4%	**0.3%**	-2.4%	-0.5%	0.1%	0.0%	-3.1%
BASE YEAR: 2022											
next 5 years	1.4%	1.4%	0.6%	2.1%	1.7%	**1.7%**	0.0%	-0.8%	0.6%	0.3%	0.3%

MECO COMMERCIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	9,815	9,484	9,815	9,815	9,815	**9,484**	(330)	(0)	0	0	(330)
2008	9,826	9,420	9,826	9,826	9,826	**9,420**	(406)	(0)	0	0	(406)
2009	9,779	9,282	9,779	9,779	9,779	**9,282**	(496)	(0)	0	0	(497)
2010	9,835	9,215	9,835	9,835	9,835	**9,214**	(620)	(1)	0	0	(621)
2011	9,977	9,203	9,976	9,977	9,977	**9,202**	(774)	(1)	0	0	(775)
2012	10,231	9,244	10,228	10,232	10,231	**9,240**	(988)	(4)	0	0	(992)
2013	10,366	9,155	10,356	10,366	10,366	**9,146**	(1,211)	(10)	0	0	(1,220)
2014	10,569	9,145	10,552	10,570	10,569	**9,129**	(1,424)	(17)	1	0	(1,441)
2015	10,819	9,126	10,795	10,820	10,819	**9,103**	(1,693)	(24)	1	0	(1,716)
2016	10,952	8,982	10,920	10,953	10,952	**8,951**	(1,970)	(32)	1	0	(2,001)
2017	11,157	8,948	11,112	11,159	11,157	**8,904**	(2,210)	(45)	2	0	(2,253)
2018	11,287	8,847	11,231	11,290	11,287	**8,794**	(2,440)	(56)	3	0	(2,493)
2019	11,450	8,774	11,387	11,454	11,450	**8,715**	(2,676)	(63)	4	0	(2,735)
2020	11,093	8,207	11,020	11,098	11,093	**8,139**	(2,886)	(73)	5	0	(2,954)
2021	11,529	8,422	11,443	11,536	11,529	**8,343**	(3,107)	(86)	7	0	(3,185)
2022	11,777	8,455	11,680	11,788	11,777	**8,371**	(3,322)	(97)	12	1	(3,406)
2023	11,916	8,418	11,811	11,938	11,919	**8,337**	(3,499)	(105)	22	3	(3,579)
2024	12,114	8,454	12,001	12,153	12,121	**8,386**	(3,660)	(114)	39	7	(3,728)
2025	12,320	8,508	12,199	12,383	12,332	**8,461**	(3,812)	(121)	63	12	(3,859)
2026	12,500	8,544	12,371	12,596	12,517	**8,526**	(3,957)	(129)	95	17	(3,974)
2027	12,710	8,615	12,573	12,850	12,732	**8,640**	(4,095)	(137)	140	22	(4,071)

Annual Growth Rates:											
prior 15 years	1.2%	-0.8%	1.2%	1.2%	1.2%	**-0.8%**	-2.0%	-0.1%	0.0%	0.0%	-2.1%
prior 10 years	1.4%	-0.9%	1.3%	1.4%	1.4%	**-1.0%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 5 years	1.1%	-1.1%	1.0%	1.1%	1.1%	**-1.2%**	-2.2%	-0.1%	0.0%	0.0%	-2.3%
BASE YEAR: 2022											
next 5 years	1.5%	0.4%	1.5%	1.7%	1.6%	**0.6%**	-1.2%	-0.1%	0.2%	0.0%	-0.9%

MECO INDUSTRIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	4,004	3,860	4,004	4,004	4,004	**3,860**	(144)	(0)	0	0	(144)
2008	3,867	3,693	3,867	3,867	3,867	**3,693**	(174)	(0)	0	0	(174)
2009	3,645	3,437	3,645	3,645	3,645	**3,436**	(208)	(0)	0	0	(209)
2010	3,618	3,364	3,618	3,618	3,618	**3,364**	(254)	(0)	0	0	(254)
2011	3,605	3,296	3,604	3,605	3,605	**3,295**	(309)	(1)	0	0	(310)
2012	3,591	3,206	3,589	3,591	3,591	**3,205**	(384)	(1)	0	0	(386)
2013	3,618	3,157	3,615	3,619	3,618	**3,154**	(462)	(3)	0	0	(465)
2014	3,704	3,169	3,698	3,704	3,704	**3,163**	(535)	(6)	0	0	(541)
2015	3,741	3,114	3,733	3,742	3,741	**3,106**	(628)	(8)	0	0	(636)
2016	3,625	2,905	3,614	3,625	3,625	**2,895**	(720)	(11)	0	0	(730)
2017	3,595	2,800	3,580	3,596	3,595	**2,785**	(796)	(15)	1	0	(810)
2018	3,562	2,695	3,544	3,563	3,562	**2,678**	(867)	(19)	1	0	(884)
2019	3,475	2,538	3,454	3,476	3,475	**2,519**	(937)	(21)	1	0	(956)
2020	3,450	2,452	3,427	3,452	3,450	**2,430**	(998)	(24)	2	0	(1,020)
2021	3,619	2,554	3,592	3,621	3,619	**2,529**	(1,065)	(27)	2	0	(1,090)
2022	3,523	2,395	3,492	3,526	3,523	**2,368**	(1,128)	(31)	4	0	(1,155)
2023	3,640	2,462	3,607	3,646	3,640	**2,436**	(1,178)	(33)	6	1	(1,203)
2024	3,649	2,427	3,614	3,660	3,651	**2,405**	(1,222)	(35)	11	2	(1,245)
2025	3,649	2,386	3,612	3,667	3,652	**2,369**	(1,263)	(37)	17	3	(1,280)
2026	3,631	2,330	3,592	3,657	3,636	**2,321**	(1,302)	(39)	26	4	(1,310)
2027	3,622	2,285	3,581	3,660	3,628	**2,287**	(1,337)	(42)	38	6	(1,336)

Annual Growth Rates:											
prior 15 years	-0.9%	-3.1%	-0.9%	-0.8%	-0.9%	**-3.2%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 10 years	-0.2%	-2.9%	-0.3%	-0.2%	-0.2%	**-3.0%**	-2.7%	-0.1%	0.0%	0.0%	-2.8%
prior 5 years	-0.4%	-3.1%	-0.5%	-0.4%	-0.4%	**-3.2%**	-2.7%	-0.1%	0.0%	0.0%	-2.8%
BASE YEAR: 2022											
next 5 years	0.6%	-0.9%	0.5%	0.7%	0.6%	**-0.7%**	-1.5%	-0.1%	0.2%	0.0%	-1.3%

APPENDIX A2: DERs - Nantucket Electric

NANTUCKET TOTAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	151	146	151	151	151	**146**	(5)	(0)	0	0	(5)
2008	152	146	152	152	152	**146**	(6)	(0)	0	0	(6)
2009	154	146	154	154	154	**146**	(8)	(0)	0	0	(8)
2010	149	139	149	149	149	**139**	(9)	(0)	0	0	(9)
2011	157	146	157	157	157	**145**	(11)	(0)	0	0	(11)
2012	157	143	157	157	157	**143**	(13)	(0)	0	0	(14)
2013	170	154	170	170	170	**154**	(16)	(0)	0	0	(16)
2014	182	163	182	182	182	**163**	(19)	(0)	0	0	(20)
2015	177	155	176	177	177	**154**	(22)	(1)	0	0	(23)
2016	187	161	185	187	187	**159**	(26)	(2)	0	0	(27)
2017	201	172	199	201	201	**170**	(29)	(2)	0	0	(31)
2018	205	172	203	205	205	**170**	(33)	(3)	0	0	(35)
2019	212	175	209	212	212	**173**	(36)	(3)	0	0	(39)
2020	213	173	209	213	213	**170**	(40)	(3)	0	0	(43)
2021	208	166	204	208	208	**162**	(43)	(4)	0	0	(46)
2022	213	168	209	213	213	**164**	(45)	(5)	0	0	(49)
2023	214	168	209	215	214	**164**	(46)	(5)	1	0	(50)
2024	220	172	214	221	220	**168**	(48)	(6)	1	0	(52)
2025	225	176	218	227	226	**172**	(49)	(7)	2	1	(53)
2026	229	179	222	232	230	**175**	(50)	(7)	2	1	(54)
2027	235	184	228	239	237	**181**	(51)	(8)	3	1	(54)

Annual Growth Rates:											
prior 15 years	2.3%	1.0%	2.2%	2.3%	2.3%	**0.8%**	-1.4%	-0.1%	0.0%	0.0%	-1.5%
prior 10 years	3.1%	1.6%	2.9%	3.1%	3.1%	**1.4%**	-1.5%	-0.2%	0.0%	0.0%	-1.7%
prior 5 years	1.2%	-0.4%	1.0%	1.2%	1.2%	**-0.6%**	-1.6%	-0.2%	0.0%	0.0%	-1.8%
BASE YEAR: 2022											
next 5 years	2.0%	1.8%	1.8%	2.3%	2.1%	**2.0%**	-0.2%	-0.3%	0.3%	0.1%	-0.1%

NANTUCKET RESIDENTIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	DELIVERIES (50/50)						DER IMPACTS				
Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	99	96	99	99	99	**96**	(2.9)	(0.0)	0.0	0.0	(2.9)
2008	99	95	99	99	99	**95**	(3.6)	(0.0)	0.0	0.0	(3.6)
2009	99	94	99	99	99	**94**	(4.3)	(0.0)	0.0	0.0	(4.3)
2010	94	89	94	94	94	**89**	(5.0)	(0.0)	0.0	0.0	(5.0)
2011	99	94	99	99	99	**94**	(5.6)	(0.0)	0.0	0.0	(5.7)
2012	99	93	99	99	99	**93**	(6.5)	(0.1)	0.0	0.0	(6.6)
2013	109	102	109	109	109	**102**	(7.8)	(0.1)	0.0	0.0	(7.9)
2014	116	107	116	116	116	**107**	(9.3)	(0.3)	0.0	0.0	(9.6)
2015	113	102	112	113	113	**101**	(10.7)	(0.8)	0.0	0.0	(11.5)
2016	119	107	118	119	119	**106**	(12.3)	(1.4)	0.0	0.0	(13.6)
2017	127	113	125	127	127	**111**	(14.1)	(1.9)	0.1	0.0	(15.9)
2018	131	115	129	131	131	**112**	(16.3)	(2.2)	0.1	0.0	(18.4)
2019	134	116	132	135	134	**114**	(18.2)	(2.5)	0.1	0.0	(20.6)
2020	141	121	138	141	141	**118**	(20.1)	(2.9)	0.2	0.0	(22.8)
2021	136	114	133	136	136	**111**	(21.6)	(3.3)	0.2	0.1	(24.6)
2022	138	116	135	139	139	**113**	(22.3)	(3.9)	0.4	0.1	(25.7)
2023	138	116	134	139	138	**112**	(22.6)	(4.5)	0.6	0.2	(26.3)
2024	142	119	137	143	142	**115**	(23.0)	(5.1)	0.9	0.4	(26.8)
2025	145	122	139	147	146	**118**	(23.3)	(5.7)	1.4	0.7	(27.0)
2026	148	124	142	150	149	**121**	(23.6)	(6.3)	1.9	0.9	(27.1)
2027	152	128	145	155	153	**125**	(23.8)	(6.9)	2.7	1.2	(26.8)

Annual Growth Rates:											
prior 15 years	2.3%	1.3%	2.1%	2.3%	2.3%	**1.1%**	-1.0%	-0.2%	0.0%	0.0%	-1.2%
prior 10 years	3.4%	2.3%	3.1%	3.4%	3.4%	**2.0%**	-1.1%	-0.3%	0.0%	0.0%	-1.4%
prior 5 years	1.7%	0.5%	1.4%	1.8%	1.7%	**0.3%**	-1.2%	-0.3%	0.0%	0.0%	-1.4%
BASE YEAR: 2022											
next 5 years	1.9%	2.0%	1.5%	2.2%	2.0%	**2.1%**	0.1%	-0.4%	0.3%	0.1%	0.2%

NANTUCKET COMMERCIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
	DELIVERIES (50/50)						DER IMPACTS				
2007	51	49	51	51	51	**49**	(2.4)	(0.0)	0.0	0.0	(2.4)
2008	52	50	52	52	52	**50**	(2.9)	(0.0)	0.0	0.0	(2.9)
2009	54	50	54	54	54	**50**	(3.5)	(0.0)	0.0	0.0	(3.5)
2010	53	49	53	53	53	**49**	(4.3)	(0.0)	0.0	0.0	(4.3)
2011	56	51	56	56	56	**51**	(5.4)	(0.0)	0.0	0.0	(5.4)
2012	56	49	56	56	56	**49**	(6.8)	(0.0)	0.0	0.0	(6.8)
2013	59	51	59	59	59	**51**	(8.3)	(0.1)	0.0	0.0	(8.3)
2014	65	55	64	65	65	**55**	(9.7)	(0.1)	0.0	0.0	(9.8)
2015	63	51	63	63	63	**51**	(11.5)	(0.2)	0.0	0.0	(11.6)
2016	66	52	65	66	66	**52**	(13.3)	(0.2)	0.0	0.0	(13.5)
2017	73	58	72	73	73	**57**	(14.8)	(0.3)	0.0	0.0	(15.1)
2018	73	57	73	73	73	**57**	(16.3)	(0.4)	0.0	0.0	(16.7)
2019	76	58	76	76	76	**58**	(17.9)	(0.4)	0.0	0.0	(18.2)
2020	71	51	70	71	71	**51**	(19.2)	(0.5)	0.0	0.0	(19.7)
2021	71	50	70	71	71	**50**	(20.6)	(0.6)	0.0	0.0	(21.2)
2022	73	51	73	73	73	**51**	(22.0)	(0.6)	0.1	0.0	(22.6)
2023	74	51	74	75	74	**51**	(23.1)	(0.7)	0.1	0.0	(23.7)
2024	76	52	76	77	77	**52**	(24.2)	(0.7)	0.2	0.0	(24.7)
2025	78	53	78	79	78	**53**	(25.1)	(0.8)	0.3	0.1	(25.5)
2026	80	54	79	80	80	**54**	(26.0)	(0.8)	0.5	0.1	(26.3)
2027	82	55	81	83	82	**55**	(26.9)	(0.9)	0.7	0.1	(27.0)

Annual Growth Rates:											
prior 15 years	2.4%	0.3%	2.4%	2.4%	2.4%	**0.2%**	-2.1%	-0.1%	0.0%	0.0%	-2.2%
prior 10 years	2.7%	0.4%	2.6%	2.7%	2.7%	**0.3%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 5 years	0.2%	-2.4%	0.1%	0.2%	0.2%	**-2.5%**	-2.5%	-0.1%	0.0%	0.0%	-2.7%
BASE YEAR: 2022											
next 5 years	2.3%	1.6%	2.3%	2.5%	2.4%	**1.7%**	-0.8%	0.0%	0.1%	0.0%	-0.6%

NANTUCKET INDUSTRIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	DELIVERIES (50/50) Reconstituted (before DER impacts)	Forecast w/only EE Reduction	Forecast w/only PV Reduction	Forecast w/only EV Increase	Forecast w/only EHP Increase	Final Forecast (after all impacts)	DER IMPACTS EE Reduction	PV Reduction	EV Increase	EH Increase	Total Impacts
2007	0.8	0.8	0.8	0.8	0.8	**0.8**	(0.0)	(0.0)	0.0	-	(0.0)
2008	1.0	0.9	1.0	1.0	1.0	**0.9**	(0.0)	(0.0)	(0.0)	-	(0.0)
2009	1.0	1.0	1.0	1.0	1.0	**1.0**	(0.0)	(0.0)	0.0	-	(0.0)
2010	1.0	1.0	1.0	1.0	1.0	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2011	1.1	1.1	1.1	1.1	1.1	**1.1**	(0.1)	(0.0)	0.0	-	(0.1)
2012	1.1	1.0	1.1	1.1	1.1	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2013	1.1	1.0	1.1	1.1	1.1	**1.0**	(0.1)	(0.0)	0.0	-	(0.1)
2014	1.1	0.9	1.1	1.1	1.1	**0.9**	(0.2)	(0.0)	0.0	-	(0.2)
2015	1.2	1.0	1.2	1.2	1.2	**1.0**	(0.2)	(0.0)	0.0	-	(0.2)
2016	1.2	1.0	1.2	1.2	1.2	**1.0**	(0.2)	(0.0)	0.0	-	(0.2)
2017	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2018	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2019	1.0	0.7	1.0	1.0	1.0	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2020	0.8	0.5	0.8	0.8	0.8	**0.5**	(0.3)	(0.0)	0.0	-	(0.3)
2021	1.1	0.8	1.1	1.1	1.1	**0.7**	(0.3)	(0.0)	0.0	-	(0.3)
2022	1.1	0.8	1.1	1.1	1.1	**0.8**	(0.3)	(0.0)	0.0	-	(0.4)
2023	1.1	0.8	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2024	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2025	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2026	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)
2027	1.1	0.7	1.1	1.1	1.1	**0.7**	(0.4)	(0.0)	0.0	-	(0.4)

Annual Growth Rates:											
prior 15 years	2.0%	-0.3%	1.9%	2.0%	2.0%	**-0.4%**	-2.3%	-0.1%	0.0%	0.0%	-2.4%
prior 10 years	0.1%	-2.4%	0.1%	0.1%	0.1%	**-2.5%**	-2.6%	-0.1%	0.0%	0.0%	-2.7%
prior 5 years	2.9%	1.6%	2.8%	2.9%	2.9%	**1.5%**	-1.3%	-0.1%	0.0%	0.0%	-1.4%
BASE YEAR: 2022											
next 5 years	-0.4%	-2.5%	-0.5%	-0.3%	-0.4%	**-2.4%**	-2.1%	-0.1%	0.1%	0.0%	-2.1%

APPENDIX B1: MODELS - Massachusetts Electric

Model: MECO ELECTRIC RESIDENTIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	55060.2115	DFE	215
MSE	256.09401	Root MSE	16.00294
SBC	2071.47463	AIC	1998.73416
MAE	12.1253215	AICC	2003.05191
MAPE	1.60431157	HQC	2028.05647
Durbin-Watson	2.0235	Transformed Regression R-Square	0.9757
		Total R-Square	0.9856

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-23899	814.4486	-29.34	<.0001	
time_trend	1	12.0828	0.4076	29.65	<.0001	
post_covid	1	56.3734	6.8860	8.19	<.0001	
hdd_jan	1	0.2138	0.005405	39.55	<.0001	
hdd_feb	1	0.1882	0.004668	40.31	<.0001	
hdd_mar	1	0.1586	0.004862	32.62	<.0001	
hdd_apr	1	0.1015	0.005819	17.45	<.0001	
cdd_jun	1	0.6833	0.0603	11.33	<.0001	
cdd_jul	1	0.9492	0.0232	40.93	<.0001	
cdd_aug	1	1.0569	0.0190	55.71	<.0001	
cdd_sep	1	1.0761	0.0298	36.15	<.0001	
cdd_oct	1	0.8445	0.1064	7.94	<.0001	
hdd_nov	1	0.0723	0.0107	6.74	<.0001	
hdd_dec	1	0.1674	0.007207	23.23	<.0001	
Bdays	1	14.4557	1.6194	8.93	<.0001	Number of Billing Days
sep09	1	38.5309	14.8473	2.60	0.0101	
jan07	1	40.6530	14.8134	2.74	0.0066	
aug14	1	53.4922	14.7760	3.62	0.0004	
aug20	1	67.2177	16.4733	4.08	<.0001	
jul20	1	58.1911	16.5027	3.53	0.0005	

Model: MECO ELECTRIC COMMERCIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	3772002.26	DFE	221
MSE	17068	Root MSE	130.64411
SBC	3036.03988	AIC	2984.0824
MAE	98.1251013	AICC	2986.26422
MAPE	1.81568453	HQC	3005.02691
Durbin-Watson	1.9580	Transformed Regression R-Square	0.8942
		Total R-Square	0.9128

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	109.7597	292.2084	0.38	0.7076	
IDX_GDP	1	25.6033	1.1028	23.22	<.0001	idx_GDP
cdd_season	1	108.7127	39.4678	2.75	0.0064	
hdd_season	1	-378.6847	41.8491	-9.05	<.0001	
cdd_season*cdd_5	1	3.3427	0.1541	21.69	<.0001	
hdd_season*hdd_5	1	0.8425	0.0516	16.33	<.0001	
Bdays	1	91.0722	8.9117	10.22	<.0001	Number of Billing Days
sep08	1	439.0602	129.3285	3.39	0.0008	
apr10	1	-319.9081	130.5865	-2.45	0.0151	
jun16	1	433.4192	130.2715	3.33	0.0010	
may20	1	-316.9232	134.2200	-2.36	0.0191	
jun20	1	-282.2918	131.8969	-2.14	0.0334	
aug20	1	461.7211	134.7054	3.43	0.0007	
sep20	1	-629.4562	131.5977	-4.78	<.0001	

Model: MECO ELECTRIC INDUSTRIAL KWH, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	27419.7334	DFE	220
MSE	124.63515	Root MSE	11.16401
SBC	1879.38698	AIC	1823.96568
MAE	8.29122583	AICC	1826.44969
MAPE	2.67250404	HQC	1846.30649
Durbin-Watson	1.9823	Transformed Regression R-Square	0.8252
		Total R-Square	0.8330

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-7.9685	24.0756	-0.33	0.7410	
IDX_empl_manuf	1	1.6876	0.0729	23.16	<.0001	idx_EMPL_MANUF
cdd_5	1	0.1133	0.008355	13.56	<.0001	RevMo Cooling Degree Days, MECo
Bdays	1	4.1664	0.7456	5.59	<.0001	Number of Billing Days
mar08	1	-61.0761	11.2566	-5.43	<.0001	
apr08	1	49.0207	11.2259	4.37	<.0001	
nov08	1	-54.0017	11.1882	-4.83	<.0001	
jun14	1	-60.3447	11.1786	-5.40	<.0001	
aug14	1	42.7413	11.2259	3.81	0.0002	
sep14	1	-59.2898	11.2381	-5.28	<.0001	
oct14	1	41.3859	11.2186	3.69	0.0003	
nov14	1	41.1771	11.2055	3.67	0.0003	
jun13	1	-44.2642	11.1753	-3.96	0.0001	
dec21	1	70.0257	11.2556	6.22	<.0001	
jan22	1	-89.6465	11.2328	-7.98	<.0001	

Model: MECO ELECTRIC RESIDENTIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	2.15199E10	**DFE**	225
MSE	95644009	**Root MSE**	9780
SBC	5055.68606	**AIC**	5017.58391
MAE	7380.80339	**AICC**	5018.76248
MAPE	0.65190599	**HQC**	5032.94321
Durbin-Watson	2.1988	**Transformed Regression R-Square**	0.7501
		Total R-Square	0.9228

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	81785	43573	1.88	0.0618	
IDX_HHolds	1	10883	453.5117	24.00	<.0001	idx_HHOLDS
jul10	1	33458	8621	3.88	0.0001	
sep14	1	-31446	8623	-3.65	0.0003	
jan16	1	-29676	8623	-3.44	0.0007	
jun16	1	-24286	8624	-2.82	0.0053	
oct16	1	-32674	8623	-3.79	0.0002	
feb19	1	-45011	8624	-5.22	<.0001	
dec20	1	-45265	8624	-5.25	<.0001	
nov21	1	24081	8626	2.79	0.0057	

Model: MECO ELECTRIC COMMERICAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	319440639	**DFE**	167
MSE	1912818	**Root MSE**	1383
SBC	3082.70942	**AIC**	3054.17506
MAE	1042.17441	**AICC**	3055.2594
MAPE	0.64313196	**HQC**	3065.74846
Durbin-Watson	2.2496	**Transformed Regression R-Square**	0.6820
		Total R-Square	0.8747

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	3122	9151	0.34	0.7334	
IDX_HHolds	1	1632	93.9230	17.37	<.0001	idx_HHOLDS
jan16	1	-3713	1246	-2.98	0.0033	
oct16	1	-4161	1246	-3.34	0.0010	
dec16	1	-3320	1246	-2.66	0.0085	
feb19	1	-4396	1357	-3.24	0.0014	
mar19	1	2961	1357	2.18	0.0305	
dec20	1	-4895	1246	-3.93	0.0001	

Model: MECO ELECTRIC INDUSTRIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	522610.074	**DFE**	230
MSE	2272	**Root MSE**	47.66778
SBC	2522.16627	**AIC**	2501.38328
MAE	35.4073843	**AICC**	2501.75009
MAPE	0.82026262	**HQC**	2509.76108
Durbin-Watson	2.5258	**Transformed Regression R-Square**	0.4738
		Total R-Square	0.9888

Parameter Estimates						
Variable	**DF**	**Estimate**	**Standard Error**	**t Value**	**Approx Pr > |t|**	**Variable Label**
Intercept	1	1163	345.3625	3.37	0.0009	
IDX_empl_manuf	1	29.8790	3.1546	9.47	<.0001	idx_EMPL_MANUF
prerecession	1	162.5218	47.2059	3.44	0.0007	
dec08	1	-147.0555	35.2042	-4.18	<.0001	
feb19	1	-166.1933	35.2034	-4.72	<.0001	

APPENDIX B2: MODELS - Nantucket Electric

Model: NANT ELECTRIC RESIDENTIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	726204.836	**DFE**	226
MSE	3213	**Root MSE**	56.68594
SBC	2620.07101	**AIC**	2585.4327
MAE	42.2200543	**AICC**	2586.41047
MAPE	5.19719868	**HQC**	2599.3957
Durbin-Watson	1.8405	**Transformed Regression R-Square**	0.8878
		Total R-Square	0.9285

Parameter Estimates						
Variable	**DF**	**Estimate**	**Standard Error**	**t Value**	**Approx Pr > |t|**	**Variable Label**
Intercept	1	-617.4719	118.8291	-5.20	<.0001	
IDX_PCI	1	7.7289	0.5926	13.04	<.0001	idx_PCI
hdd_season	1	-176.4283	17.2035	-10.26	<.0001	
cdd_season*cdd_4	1	3.0821	0.0906	34.01	<.0001	
hdd_season*hdd_4	1	0.3119	0.0240	13.01	<.0001	
Bdays	1	21.0310	3.5387	5.94	<.0001	Number of Billing Days
aug03	1	-123.8409	52.8251	-2.34	0.0199	
jul10	1	-201.9905	53.0318	-3.81	0.0002	
sep21	1	-169.5329	53.6464	-3.16	0.0018	

Model: NANT ELECTRIC COMMERCIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	19120951.4	DFE	223
MSE	85744	Root MSE	292.82107
SBC	3408.24952	AIC	3363.2197
MAE	217.736392	AICC	3364.85934
MAPE	6.52851326	HQC	3381.37161
Durbin-Watson	1.8735	Transformed Regression R-Square	0.7720
		Total R-Square	0.8241

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-101.1780	606.5648	-0.17	0.8677	
IDX_RPI_HH	1	7.9062	0.9966	7.93	<.0001	
cdd_4	1	7.6415	0.3956	19.32	<.0001	RevMo Cooling Degree Days, Nantucket
Bdays	1	49.6663	18.6993	2.66	0.0085	Number of Billing Days
sep04	1	1132	281.4894	4.02	<.0001	
aug06	1	-1629	296.9354	-5.48	<.0001	
sep06	1	1946	292.4831	6.65	<.0001	
mar17	1	-1114	292.4263	-3.81	0.0002	
apr17	1	1627	292.7919	5.56	<.0001	
sep17	1	1283	280.9011	4.57	<.0001	
feb20	1	1196	294.4561	4.06	<.0001	
mar20	1	-2075	293.6484	-7.06	<.0001	

Model: NANT ELECTRIC RESIDENTIAL CUSTOMER COUNT (Est.Period: Jan2008 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	99800.1602	DFE	158
MSE	631.64658	Root MSE	25.13258
SBC	1710.49434	AIC	1653.42563
MAE	18.6737251	AICC	1657.78232
MAPE	0.1599725	HQC	1676.57242
Durbin-Watson	1.5226	Transformed Regression R-Square	0.9829
		Total R-Square	0.9963

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	3163	555.1437	5.70	<.0001	
IDX_HHolds	1	90.2595	5.8803	15.35	<.0001	idx_HHOLDS
jun	1	22.8886	6.3106	3.63	0.0004	
jul	1	25.1090	8.1967	3.06	0.0026	
aug	1	30.3397	8.8915	3.41	0.0008	
sep	1	40.7329	8.9641	4.54	<.0001	
oct	1	47.4324	8.2287	5.76	<.0001	
nov	1	25.4108	6.4048	3.97	0.0001	
mar08	1	-108.5476	21.2044	-5.12	<.0001	
apr08	1	-135.0737	21.2044	-6.37	<.0001	
mar09	1	-50.9929	18.3780	-2.77	0.0062	
may10	1	-55.4700	18.6463	-2.97	0.0034	
jul10	1	170.1173	19.0229	8.94	<.0001	
feb14	1	-40.9006	18.3780	-2.23	0.0275	
apr16	1	112.8683	18.3781	6.14	<.0001	
feb20	1	-1704	18.3780	-92.73	<.0001	
jan21	1	-57.5265	18.3781	-3.13	0.0021	

Model: NANT ELECTRIC COMMERICAL CUSTOMER COUNT (Est.Period: Jan2003 to aug22

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	15655.3553	DFE	226
MSE	69.27148	Root MSE	8.32295
SBC	1716.13313	AIC	1681.49482
MAE	6.50876582	AICC	1682.47259
MAPE	0.43519637	HQC	1695.45782
Durbin-Watson	2.1604	Transformed Regression R-Square	0.9535
		Total R-Square	0.9967

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-604.7143	85.6570	-7.06	<.0001	
IDX_HHolds	1	22.9299	0.9341	24.55	<.0001	idx_HHOLDS
jun05	1	-47.3045	6.1453	-7.70	<.0001	
jan08	1	-26.6173	7.7424	-3.44	0.0007	
feb08	1	-66.4919	9.4573	-7.03	<.0001	
mar08	1	-124.7152	9.4573	-13.19	<.0001	
apr08	1	-26.2787	7.7424	-3.39	0.0008	
may16	1	-17.7347	6.1453	-2.89	0.0043	
feb20	1	-376.9208	6.1453	-61.34	<.0001	

APPENDIX C: Regression Statistics Discussion

All models are checked for overall goodness of fit, statistical validity and reasonable of results. In general, the following items are reviewed for each model.

1) Overall Goodness of Fit: Does the model adequately capture the explanatory aspects for the dependent variable? For example, for the residential use-per-customer model, do the explanatory economics, demographics, weather, calendar, and other independent variables adequately explain the monthly energy use. Several statistical tests can be used to gauge this. For this forecast, "Adjusted R-squared" is the primary test used. Values are expressed as a fraction of 1.0 and values closest to 1.0 are best. In theory, a 1.0 means that the variables being used explain 100% the energy use. For the most part residential models generally have Adjusted R-Squared values of 0.9 or higher, commercial models 0.85 or higher and industrial models 0.75 or better (based on past experience).

2) Correlation and Causality: Are the explanatory variables correlated with energy usage? That is, as a variable goes up or down, does the energy do the same? Are the variables causal? For example, can it be said that as summer weather gets hotter, would the expectation be that energy use would go up due to air conditioning and other cooling loads? For this forecast, correlation statistics are reviewed for correlation strength. Both general industry practice and experience are used to gauge causation.
3) Statistical Significance of Explanatory Variables: Are the independent variables statistically significant? P-values and T-statistics are used to determine this. Lower p-values indicate higher statistical significance. Generally, p-values less than or equal to 0.05 are considered statistically significant. However, in certain cases, explanatory variables with higher values (up to 0.10 or 0.15) may be useful to a model if that variable is known provide explanatory value.

4) Outliers and Influential Observations: There are times when several of the observations in the historical input dataset may be in error (ex: billing error) and have an undue influence on the outcome. An analysis of the residuals as well as statistical tests are used to determine this (statistical tests include R-Student and Cook's D). Outliers are corrected if possible or assigned a categorical 0 or 1 to exclude them from the model if they cannot be corrected.

5) Autocorrelation: Since energy usage is a time-series, the residuals may not be independent of time and can be autocorrelated, meaning the residuals can be correlated with prior observations of themselves, which can distort results. The Durbin-Watson statistic is used to test for autocorrelation (values of 2.0 indicate no influence, while values less than 1.6 or greater than 2.4 indicate possible autocorrelation). Autocorrelation is corrected with an autoregressive error model.

6) Additional Analysis: Additional analysis is done to ensure goodness of fit and the robustness of the model including a residual analysis, testing for heteroscedasticity, normality, and multicollinearity.

7) Reasonable Results: Is the resulting forecast reasonable? Is the forecast similar to historical trends? For example, if the residential customer counts have been growing annually at 0.5% per year over the last five years it would be expected, barring any significant changes in the economy or other explanatory variables, to continue to grow similarly over the next few years of the forecast. Major departures from historical trends require an explanation (for example a change in economic outlook or other factors.