Electric Sector Modernization Plan

Accelerating a Just Transition to a Reliable and Resilient Clean Energy Future

September 2023

Table of Contents

EVERSOURCE

Table of Figures

Table of Tables

1.0 Executive Summary

In recognition of the critical role the electric distribution system will play as a key enabler of clean energy and electrification over the next 25 years, Eversource has crafted this Electric Sector Modernization Plan ("ESMP") with an ambitious and detailed plan established for the next five and ten years and a vision for the steps that will be needed to achieve decarbonization objectives by 2050.

In recognition of the critical role the electric distribution system will play as a key enabler of clean energy and electrification over the next 25 years, Eversource has crafted this ESMP with an ambitious and detailed plan clearly established for the next five and ten years and a vision for the steps that will be needed to achieve decarbonization objectives by 2050. The 10-year plan increases grid electrification hosting capacity by 180% or 3.4 GW enabling 2.5 million electric vehicles and 1 million residential heat pumps and enables 2.2 GW of solar. In aggregate, this plan achieves the Commonwealth's 2040 goal. Unlocking the potential of a clean energy grid will support the aggressive clean energy targets established by the Commonwealth of Massachusetts aimed at transitioning to a decarbonized future. As a result of the infrastructure and technology platforms included in this plan, hundreds of communities across Massachusetts will be fully enabled in line with the Commonwealth's 2050 goals. Ensuring this transition is delivered with the input of the Company's diverse customer base, including its environmental justice communities, will require robust, transparent, and meaningful dialog. In this plan, the Company proposes establishment of a Community Engagement Stakeholder Advisory Group (CESAG) to engage with communities throughout implementation. To ensure affordability in delivering a grid that enables clean energy while becoming more resilient to the impacts of climate change, the Company has employed careful, data-driven planning to ensure the most cost-effective solutions are implemented, including technology platforms to increase system efficiency using clean energy resources. Further, the creation of a new Gas-Electric Coordinated Integrated Planning Working Group, will ensure projects are considered comprehensively. As a result of the plan, Massachusetts will experience benefits with respect to health outcomes, workforce, and economic development.

As a result of the plan, Massachusetts will experience benefits with respect to health outcomes, workforce, and economic development.

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

Eversource is committed to being a catalyst for an equitable clean energy future. This ESMP presents the Company's comprehensive roadmap to enabling a clean energy future that delivers the environmental, health and economic benefits of the Commonwealth's decarbonization and climate change mitigation, with a focus on delivering positive outcomes in historically marginalized communities. The Company's proposed distribution infrastructure and technology platform creates a reliable and resilient foundation to implement current and inform future clean energy program designs to propel adoption of customer electrification and the integration of clean energy resources.

With its Clean Energy Climate Plans, the Commonwealth of Massachusetts has established aggressive clean energy targets aimed at transitioning to a decarbonized future. In recognition of the critical role the electric distribution system will play as a key enabler of clean energy and electrification over the next 25 years, Eversource has crafted this ESMP with an ambitious and detailed plan clearly established for the next five and ten years and a vision for the steps that will be needed to meet decarbonization targets by 2050.

Equity, Transparency and Engagement

Submission of this ESMP to the Grid Modernization Advisory Council ("GMAC") is an important first step in increasing the transparency and inclusiveness of the Company's infrastructure investment decision making. To help inform how Eversource can further enhance its stakeholder and community engagement, Eversource in conjunction with the other Massachusetts electric utilities is proposing the development of a Community Engagement Stakeholder Advisory Group ("CESAG"), made up of representatives mutually agreed upon by Eversource and members of the GMAC. The primary objective of the new advisory group is to develop a community engagement framework that can be applied to the major infrastructure projects referenced in Section 6.5.1. Eversource envisions that equity considerations will be a core tenet of this framework. The Company will continue to work with the GMAC prior to submission of this ESMP to the Massachusetts Department of Public Utilities ("DPU") in order to gather feedback through effective community outreach, especially from environmental justice communities, to ensure that their voices and feedback are incorporated in this ESMP.

A Comprehensive Plan Based on Common Objectives

As an electric distribution company ("EDC"), Eversource is responsible for ensuring the safety and reliability of the electric distribution system, including planning, and building the infrastructure and implementing technologies needed to meet the future demands of electrification and growth in distributed energy resources ("DER"). The Company oversees multiple clean energy initiatives, including industry-leading energy efficiency and demand response programs and initiatives to support electric vehicle charging as well as modernization of the grid through the deployment of enabling technology.

Historically, these efforts have often been viewed in isolation, with their evaluation and approval occurring over varying time horizons based on objectives specific to a given initiative. By translating the sequencing of the grid infrastructure implementation plan into available per capita electrification hosting capacity in each city for every year within the ten-year forecast period, this ESMP links all the Company's efforts together into an innovative roadmap for the near and long-term for the first time.

Because a significant portion of this decarbonized future will be derived from the electrification of gas customers, the lack of complete overlap between gas and electric service territories presents complications with respect to planning and execution. Consequently, another major change in the current construct is a proposed integrated energy plan that is coordinated across gas and electric utilities in the Commonwealth. While the initial focus would be on data sharing and developing a common understanding of gas plans developed by gas local distribution companies (LDCs) and electric plans developed by the EDCs, the ultimate objective of enabling development of a coordinated EDC-LDC long-range capital plan is a necessary component of reliable transition to a decarbonized future in coordination with the Commonwealth's national-leading energy efficiency programs.

Coordinated, Analytics-Based Planning is the Basis for Cost-Effective Investments

In this period of rapid change, characterized by increasing impacts of climate change, technology evolution, and the imperative to think differently about ensuring a just transition to a decarbonized future, the ESMP sets forth a sustainable, cost-effective path to 2050, driven by analytics, sound planning, and workforce training for those with jobs that may be displaced due to reduced dependency on fossil fuels. A just transition will require a diverse and inclusive workforce and close collaboration with all stakeholders working together towards the shared goal of a decarbonized Commonwealth across all sectors.

Absent the comprehensive, coordinated plan established in this ESMP, the likely outcome is a cost inefficient plan, misaligned with the Commonwealth's objectives and in the worst case, adverse reliability outcomes with the Company continually placed in a reactive mode attempting to increase hosting capacity of the grid out of sync with its original plan and associated sequence. Additionally, in such a scenario customers would be frustrated by an inability to participate in DER and decarbonization opportunities.

Rather than reacting to isolated events and focusing on one-off solutions, the ESMP presents a proactive, thoughtful, and comprehensive approach to near- and long-term planning. This efficient framework maximizes benefits from their associated costs, highlighting opportunities to focus attention on equitably bringing the benefits of clean energy solutions to all customers, especially those in environmental justice communities.

As the available electrification headroom on each local distribution system continues to increase with upgrades to the infrastructure, electrification program implementation can be calibrated with the applicable electrification hosting capacities at individual large bulk substations – and by extension in the communities served by those bulk substations. Similarly, as the available solar hosting capacity on each local distribution system continues to increase as upgrades are made to distribution system infrastructure, solar program implementation can be calibrated with the applicable solar hosting capacities at individual large bulk substations – and by extension in the communities those solar facilities exist. Planning for future solar interconnections ought to be indistinguishable from planning for future electrification. This linkage between implementation of clean energy programs and grid capacity is critical to ensuring the Company maintains safe and reliable service while customers electrify and adopt clean energy resources. Such coordination across clean energy programs and grid infrastructure capacity in turn drives innovation within every aspect of EDC functions – rates, regulatory, technology, planning, construction, operation, workforce development and by extension, the overall utility capital planning process.

The Company's Five- and Ten-Year Plans Include Planned and Proposed Investments Required to Meet the Challenges Ahead

The Company has an established electric operations budget supported by existing rate mechanisms that includes investments in reliability, new customer growth, basic business, storm repairs, and capacity for peak load including economic growth. As described in Section 6, as a comprehensive whole, these investments are the foundation of the Company's roadmap to support a transition to a cleaner energy future. These programs will be managed in coordination with the Company's established energy efficiency and demand response programs. Significant investment in new substations is anticipated in the Company's plans. This includes substation projects that are substantially underway (i.e., expected in service by 2029) and projects that are in the planning stage for 2030-2034.

The five-year plan also includes new investments identified as needed to support and enable the clean energy transition, and as described in Section 7, are incremental to the Company's established electric operations budget existing rate mechanisms.

- With the sunset of the Company's grid modernization plan in 2025, further support will be needed to invest in technology to enable the use of DER as grid assets.
- Recent findings on the specific threats to infrastructure resulting from climate change have accelerated the need to propose an expanded program to harden the distribution grid.
- Building upon the established CIP cost allocation framework, the Company is proposing seven additional areas to support DER interconnections.
- Focusing on the needs of underserved communities, the Company has developed an innovative proposal to support low-income ownership of solar generation.

There is an Imminent Need to Increase the Capacity and Flexibility of the Electric Grid

Decarbonization needs are driving a seismic shift toward clean energy resources both on the supply and demand sides. The Company began with the Commonwealth's goals in mind in development of the plan – translating the clean energy goals and climate vulnerability challenges into one comprehensive safe, reliable, and resilient plan. The significant shift toward intermittent renewable supply side resources coupled with the once in a generation increase in electric demand are placing a significant stress on the current grid – driving the need to significantly upgrade the grid infrastructure capacity as well as invest in the people, process, and technologies necessary to modernize the future grid operations. During the same time horizon, climate change is driving a significant negative shift toward increased frequency and intensity of storms in New England which drives an urgent need to harden the electric infrastructure. As detailed in Section 4, these stresses are not theoretical outcomes in a distant future. Rather, they are the reality on the system today and as shown in Section 5, the economic growth-driven electric demand increase is imminent.

To continue to provide safe and reliable service and meet the imminent demand increases by 2035, the Company needs to construct fourteen new and upgrade twelve existing substations. Eversource views bulk distribution substations as clean energy hubs that create the necessary headroom on the electric system to accommodate future system demand and electrification supply and are therefore a critical element of the Company's ESMP. Further, to continue reliable integration of solar necessary to meet the pace of the Commonwealth's Clean Energy Climate Plan, the Company also needs to construct three new and upgrade fourteen substations. Addition of these new bulk substations would also require associated new transmission lines. This acceleration of transmission and distribution ("T&D") infrastructure necessitates siting and environmental permitting reform to allow for the large number of major bulk substations and their associated transmission upgrades to move through their project lifecycle in parallel – ensuring electrification is not enabled in one community at a time.

There will be multiple solutions required to cost effectively meet the need for increased capacity and flexibility. Adding new substations that transform power between the transmission and distribution systems is the foundation to make a meaningful and sustainable step-change in the amount of load and generation an area can accommodate. The need for new substations in all areas of the Company's service territory is undeniable and urgent. Substations alone, however, will not be adequate to deliver on relatively low-cost opportunities to integrate clean energy DER as grid assets on the distribution system. Whereas new substations will dramatically increase capacity, when paired with technology to optimize the use of non-traditional grid assets, such as virtual power plants ("VPP"), the combination makes the most of both solutions in a way that is sustainable and reliable.

Guided by a Vision for 2050

The Company's assessment of both the needs and solutions of the grid over the next ten years is in large part informed by its view of what it will take to achieve the Commonwealth's objectives for decarbonization by 2050. As described in Section 8, driven by heating and transportation electrification, the electric demand growth will continue to rise beyond 2035. Decisions taken in the near term must ensure that the infrastructure buildout is not undersized and avoid short-term design thinking. As described in Section 9, however, infrastructure investment alone will be insufficient given the magnitude of the challenge. Innovation in rate design, siting and environmental permitting reform, Advanced Metering Infrastructure ("AMI") implementation, continued investments in Energy Efficiency, clean energy policy, and technology enablement will all be a part of the solution. Specifically, policy designs to incentivize specific heating electrification technologies, managed charging of electric vehicles as well as incentives for workplace charging would work in concert with the Company's infrastructure buildout to drive increased efficiency of the overall plan. Eversource is committed to continue playing an active role in shaping all these areas in support of a cleaner energy future.

Finally, like every long-term plan, the 2035 to 2050 plan is not a static plan. By linking the Commonwealth's clean energy plan on specific electric forecasts, Eversource is committing to continuing to work with the policy makers on future iterations of the Commonwealth's policies.

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

The Company's ESMP 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. By providing a comprehensive view of all the Company's plans to invest in building a safer, more reliable, more resilient electric distribution system and providing options to customers to engage in the clean energy transition, the ESMP provides a complete roadmap detailing the drivers of investment needs and prioritized solutions to maximize customer benefit, with a focus on historically marginalized communities.

Specifically, the plan is represented in two different time horizons – the Ten-Year Plan and the 2035-2050 Plan.

2024-2035

Taking into consideration expected impacts from large step loads, electrification of heating and transportation, and off-sets driven by energy efficiency and DER, the result is a projected 16% increase in net electric demand in the ten-year forecast period, raising the total peak demand in the Commonwealth served by Eversource from 6.1 GW to 7.4 GW. Results are provided for each of the Company's planning regions. To meet this demand increase, the Company's ten-year plan to maintain safe and reliable service includes construction of fourteen new substations and upgrades to twelve existing substations. Further, to continue reliable integration of Solar necessary to meet the pace of the Commonwealth's Clean Energy Climate Plan, the Company also needs to construct three new substations and upgrade fourteen existing substations. The plan also includes battery storage systems in the Metro Boston and Southeast regions, as well as construction of a new and replacement of an existing undersea cable to Martha's Vineyard.

These bulk substation upgrades and infrastructure additions by 2035, in aggregate, increase the electrification hosting capacity by about 180% to 3.4 GW. The upgrades include one approved, five pending and seven newly proposed Capital Investment Plans ("CIPs"), which in concert with the load-driven upgrades enable 2.2 GW of solar at a bulk station level <u>beyond</u> the Commonwealth's 2040 goals or 72% of its 2050 goals. These upgrades are necessary to ensure imminent electric demand on the grid can continue to be served with sufficient capacity on the distribution system, and in doing so, creates available headroom to enable electrification.

Overall, to the extent the electrification and solar programs are coordinated with the grid capacity upgrades, this ESMP 10-year plan enables 135% of the Company's 2035 peak forecast which includes 100% of the Commonwealth's 2035 objectives. It even supports 100% of the Company's 2040 forecast, which again includes 100% of the Commonwealth's 2040 clean energy goals in Eversource's service territory. Across the Eversource territory, the 2035 available electrification headroom therefore enables 2.5 million Electric Vehicles (Statewide) and the equivalent of 1 million residential Heat Pumps (Statewide).

In Section 9, the Company also proposes a new DER planning framework to address outstanding gaps as well as different cost allocation mechanisms – expanding on the CIP cost allocation method by accounting for future customer electrification needs while proactively building the infrastructure to support future solar growth in high-potential areas not currently designed to interconnect solar.

The Company recognizes that this major infrastructure investment – specifically addition of new substations required by 2035, to ensure that the distribution system is able to support the projected electric demand (from both load and DER), will require thoughtful engagement with the local communities to assist with site selection, design and construction consistent with the

Company's Equity framework. Each new substation, station upgrade and battery storage project also require extensive street distribution line upgrades or new distribution lines to ultimately relieve loading on existing distribution feeders. Active stakeholder engagement in the EDC decision-making process for new bulk substations is critical to the successful execution of these projects.

In addition to these infrastructure capacity plans, reflecting the increased challenges of maintaining service levels given the impacts of climate change, the Company is proposing to increase investment in strategic undergrounding and other hardening programs over a ten-year period, to provide a 14% improvement in all customer outage minutes, including major storms.

Building system capacity with substations and battery storage systems will provide a critical foundation for enabling electrification and reliable interconnection of DERs. A comprehensive and cost-effective total solution to address barriers to meeting the Commonwealth's clean energy objectives, however, must include technology platforms that support customer engagement and the use of DERs to provide grid services to increase flexibility and address local constraints. One of the most important foundational investments is the Company's deployment of AMI. By 2028, all customers will have greater insights into their usage information and more tools to engage in demand response and clean energy programs. To support the use of customer-owned DER as a grid asset, the Company is proposing investments that will enable the use of VPP technology to address system constraints and defer the need for system upgrades into the future where applicable.

2035-2050

The base case shows the Company increasing its overall system electric demand from a 6.1 GW summer evening peak to a 15.3 GW winter morning peak by 2050. This is an unprecedented increase in electric demand driven by a combination economic development and electrification of the heating and transportation sectors. The majority of this 150% increase in electric demand by 2050 is driven by electrification of heating needs (about 50%) with the remaining driven primarily by electrification of transportation needs (25%) and normal load (25%). The large bulk substations in the ten-year planned have a significant impact on increasing the electrification hosting capacity – which results in the WMA region being best positioned (at a regional level) to fully enable electrification, followed by Metro Boston, Southeast, and Metro West with capacity deficiencies of 900 MW, 1.7 GW, and 2.0 GW respectively to enable the full 2050 electrification future. With the addition of four new bulk substations and upgrades to eleven substations planned beyond 2035, Metro Boston will be well positioned to enable the full 2050 electrification future, reducing the aggregated 4.6 GW capacity deficiency to 3.3 GW (1.7 GW in Metro West and 1.6 GW in Southeast, after planned upgrades beyond 2035 in those regions also). To close this 3.3 GW gap, outside of other solutions, the Company would need to construct eleven additional new substations in the Metro West and ten additional new substations in the Southeast region.

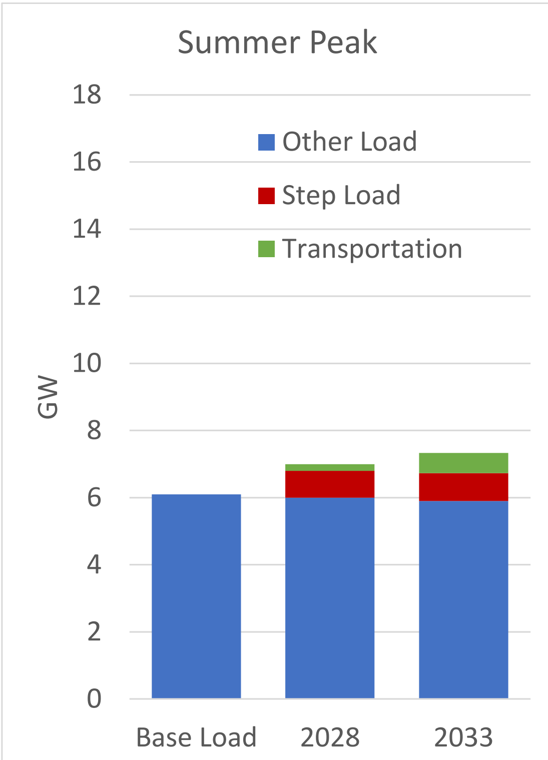


Figure 1: Summer Peak Forecast

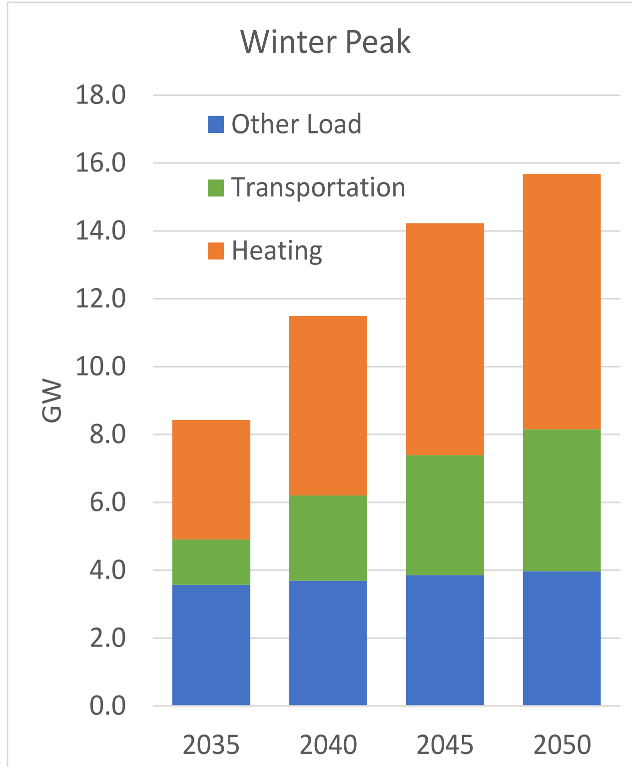


Figure 2: Winter Peak Forecast

However, solutions beyond large bulk substation additions are needed. These solutions may be different for each sub-region (excluding the Western sub-region) where capacity deficiency remains. The distribution grid would benefit from transition to electrified district heating in Metro Boston, more residential customers adopting ground-source heat pumps in Metro West and Southeast (if scalable), stronger incentives for workplace EV charging in Metro Boston and managed charging for EVs at homes. Additionally, closer coordination across gas and electric companies would provide more visibility on heating demand to inform right-sizing electric upgrades. Additionally, transparency is also needed on off-delivered fuels as their propensity to adopt electric heating may be more organic.

- **Metro Boston:** With the addition of two new substations and upgrades to eight substations in this region, Metro Boston is well positioned to enable the full 2050 electrification growth. Additionally, solutions like electrification of the steam district heating system (with service directly from the transmission system) in the downtown area could help reduce the need for individual building heating electrification, reducing the associated demand, and thereby further improving the available distribution bulk substation headroom.
- **Southeast:** In this sub-region, the majority of the 1.6 GW capacity deficiency can be attributed to electric heating – given the larger homes, on a per capita basis, the electric

heating demand is substantially higher than in other sub-regions. Given that the Cape area gas heating is serviced by National Grid, closer Gas-Electric coordination with the LDCs across utilities would inform how much of the building space requires heating – and how much of the building space is empty during winter months – and therefore, may not need to be included in grid electrification planned capacity despite homeowners converting to air-sourced heat pumps (ASHP). Further, given that distances between homes are substantial, single entity ground-Sourced heat pumps (GSHPs) deployed in this sub-region would be significantly helpful – albeit with higher upfront capital cost. More specifically, if 50% of residential homeowners (assuming year-round occupancy) install GSHPs, the 1.6 GW electric capacity deficiency compresses to 1.1 GW. This in and of itself, reduces the need to construct new bulk substations from ten down to four. If managed electric vehicle charging could effectuate a 20% reduction in EV load, it could potentially further reduce the capacity deficiency to 0.9 GW, potentially driving down the number of new bulk substations from four to three.

- **Metro West:** In Metro West, about 40% of the demand increase beyond 2035 results from Electric Vehicle charging. While it is evident from current academic studies that the majority of EV charging occurs at homes, with policy designs including facilitation of subsidized workplace charging, some of that electric vehicle charging demand could be shifted into Metro Boston to take advantage of the electrification hosting capacity created by the newly constructed bulk substations in this period. Also, because of the significant pool of vehicles plugged in, staggered charging and other managed charging initiatives can then be deployed in downtown areas to optimize demand over the workday time-period. Because the Company already incorporate this assumption into the load models developed by region, Eversource asserts the importance of this design to reduce the overall EV charging demand driven infrastructure build out. Like the Southeast, if 50% of residential homeowners were to adopt GSHP in lieu of ASHP, the 1.7 GW capacity deficiency is compressed to 1.2 GW by 2050, which in turn reduces the eleven new bulk substations needed in Metro West region beyond 2035 down to seven. If managed electric vehicle charging were able to effectuate a 20% reduction in EV load, it could potentially further reduce the capacity deficiency to 0.9 GW, potentially driving down the number of new bulk substations from seven to three.

The Company has explored other mechanisms to manage electric demand reductions but finds some specific applications such as Electrification Heating Demand Response as difficult to yield tangible demand reductions sufficient to defer or avoid necessary grid upgrades. The Company is also investigating the potential for more flexible load, through mechanisms such as winter active demand response of process or water heating load as well as vehicle to grid, but these areas are in too nascent of a stage for Eversource to develop a potential load reduction at this time. The Company will continue to work with solution providers to increase the viability of these technologies to suppress demand increases and improve system efficiency.

Another critical component of achieving a just transition to a clean energy future is rethinking rate-designs. The Company has explored some of the foundational principles of rate-design and recognizes the need for further collaboration on specific proposals. While the Company does not specifically propose new rate designs in its ESMP, the Company acknowledges a collective need to shift away from volumetric rates toward demand charge-based rate designs to ensure that necessary utility infrastructure investments as well as the Commonwealth's clean energy program costs are recovered from the broadest customer segments, while ensuring that usage in this electrified future is not being penalized. As the Company moves to an increasingly electrified system, it is important that careful consideration be given to cost allocation and rate design principles to ensure a just transition. In particular it will be important to design rates and allocate costs fairly so as not to shift costs around or over-burden any particular class of customers. The Company is concerned that the transition to an electrified future happens in an equitable and just manner and supports the establishment of the Equity Working Group as part of the GMAC to address concerns.

Finally, certain benefits of the Company's ESMP are documented in Section 12, with particular attention to workforce development, economic growth, and health outcomes. The Company reiterates its commitment to expanding on successful programs to hire and train the workforce of the future and outlines estimates of total job creation potential of approximately 20,000 jobs over the ten-year period. The Company also estimates an incremental economic development benefit to the Commonwealth of approximately $2.9 billion over the ten-year period due to its ESMP. As an enabler of clean energy solutions, the ESMP will result in improved health outcomes for Massachusetts residents, including those disproportionately impacted by environmental pollutants and heat-related ailments.

1.3. Service Territory Overview

Eversource distribution systems can be broadly segmented into four sub-regions: Eastern Massachusetts (EMA)-North Metro Boston, EMA-North Metro West, Southeast Massachusetts (SEMA) and Western Massachusetts (WMA). Each sub-region has its unique set of challenges for which the EDCs must develop planning solutions. Metro Boston and Metro West areas have seen a significant increase in electric demand driven by each region's success in key business areas such as life sciences laboratories as well as broader economic growth that surpasses most regions in the nation. Metro Boston is also exposed to an elevated risk of coastal flooding due to climate change. In the past decade, however, Eversource has only constructed three new bulk distribution substations in Metro Boston and Metro West – one in the Seaport district of Boston, one in the town of Brighton, and another in the Longwood Medical area. Due to this pace of economic growth surpassing the pace of construction of large new distribution infrastructure upgrades, the available distribution capacity headroom has rapidly diminished.

This has accelerated the need for construction of four new bulk substations and expanding four existing bulk substations by 2029 in the Metro Boston and Metro West regions to continue to maintain a robust and reliable electric service, especially in the light of future electrification needs. These bulk distribution substations, or clean energy hubs, create the necessary headroom to accommodate future system demand and electrification supply. Additional details on adjacent substation capacity deficiencies ameliorated with these new bulk substations are included in Sections 4 and 6.

While the greater Boston region is experiencing capacity deficiencies due primarily to significant load growth, the SEMA region has seen a significant growth in DER, primarily solar photovoltaic (PV) generation and PV combined with battery energy storage systems (BESS). The current installed solar in conjunction with queued interconnection requests, have reached 55% of peak demand in the Southeastern region. The impacts of high penetration of inverter-based, variable generation on the system lead to capacity constraints resulting from reverse power flows during off-peak hours and voltage issues on the distribution system. This has accelerated the need to not only construct or expand eight bulk substations in the region but propose alternative cost allocation mechanisms to equitably distribute costs of infrastructure upgrades based on benefits derived not just by solar developers but by distribution customers broadly. Upgrades to these bulk substations coupled with transmission upgrades would enable about 1 GW of clean energy from solar PV on local distribution systems in southeast Massachusetts to be supplied via the transmission system into distribution systems in Metro Boston and Metro West load centers. The Cape region of SEMA is also particularly exposed to high wind speeds during storms, necessitating hardening upgrades focused on this subregion discussed in more detail in Section 10.

The Western region has also seen a significant growth in solar PV with current installed plus queued interconnections reaching 63% of peak demand in this region. Additionally, this region has traditionally been designed to supply power to sparse and geographically distant customers through very long overhead distribution lines, typically over 20 miles, which are significantly bulk exposed to causes of outages. With the additional impacts of climate change, the need to harden these distribution systems through a combination of strategic undergrounding, creation of new bulk substations to reduce the distribution line risk exposure and rebuilding overhead structures is even more urgent and further explained in Section 10.

While upgrades to the distribution systems to increase capacity are critical to enable a reliable transition to a decarbonized future, there are other existing distribution capital programs that are necessary to continue to maintain safe and reliable service to Eversource's customers. Extensive reliability programs ensure that the aging infrastructure continues to be upgraded using quantitative data-driven approaches to inform efficient replacement decisions. Investments in technologies support real-time operation of the grid, including communications infrastructure, outage management systems and geographic information systems to maintain asset data.

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

As the clean energy transition impacts the generation, transmission, and distribution of electricity in support of a cleaner energy future, customers will be increasingly empowered with options to engage in clean energy solutions and tools to manage energy consumption and costs.

Achieving a just transition requires tackling the challenges faced by communities and workers as they shift toward sustainable livelihoods, while also ensuring that the benefits of the zero-carbon and resilient economy are shared fairly. One of the core tenets of this just transition is therefore ensuring equitable access to a safe, reliable, and resilient electric power system and empowering the workforce necessary to execute on this ESMP. Customers in the modern era are increasingly reliant on their electric service for daily living and transportation; this is especially important for customers disproportionately impacted by power outages due to economic or health constraints. As climate change increases the frequency of major storm events, the challenge of maintaining reliable service will increase. Customers require a plan to ensure that, despite growing threats, power will be available when it is needed. The Eversource ESMP is aimed at building a more reliable and resilient grid, ensuring no communities are left behind and unable to benefit from the clean energy transition.

Unlocking the full range of customer benefits from the clean energy transition will require a grid that is flexible and able to respond to a variety of customer and community needs. The investments under the Eversource ESMP reflect a future where urban communities investing in electric buses for public transportation will not be delayed by the need to build out infrastructure to meet their specific need. Rural areas seeking to support community solar projects do not have to wait for the interconnection queue to clear before moving forward. Businesses with flexible load will have multiple options to monetize their energy management while reducing their carbon footprint. Homeowners seeking to install a heat pump will not have to wait for local grid upgrades to enable increased load. Customers seeking out opportunities to lower their electricity bill will have greater access to information and suggestions for efficiency programs. In short, the grid will be not a barrier to but an enabler of the benefits of the clean energy economy in Massachusetts, regardless of how customers want to engage.

In addition to providing a safe, reliable, resilient, and flexible electric system, the grid of the future will be characterized by technologies that directly empower customers. One of the most significant changes for Eversource customers in the future will be the introduction of AMI. This will enable increased customer access to more granular usage information, improving the customer's understanding of energy savings opportunities. This information has the potential to be powerful for the customer when combined with new rate designs and participation in energy efficiency programs and demand-response programs. AMI will also improve the efficacy of customer information tools such as load disaggregation applications. Customers will benefit from more timely updates from the Company, such as mid-cycle high bill and customer-directed bill alerts, which are service offerings proven to be of value to customers. In addition, call center representatives will have access to more granular data, putting them in a better position to help customers understand how changes in their usage impact changes in bill amounts and recommend participation in energy efficiency and demand response programs. Another customer benefit of AMI technology is improved frequency and precision of communications during outages and storm restoration, as well as reduced time for meter transactions, including the expedient and efficient activation of new service connections.

A just and equitable transition will require a greater focus on ensuring customers with economic, health or language constraints have targeted and specific access to the benefits of clean energy. With AMI, for instance, customer communication about ways to access features such as high bill alerts will need to be available in multiple languages. Low-income customers who previously believed investing in solar generation was out of reach financially may benefit from the Company's proposed plan for on-bill financing described in Section 6. The build out of system capacity and infrastructure to accommodate increased load will need to consider ways to prioritize support for environmental justice communities that want to reduce air pollution in their homes and communities through electrification of homes and public transportation fleets.

Over time, the Eversource ESMP investments will facilitate the equitable clean energy transition. These investments are designed to maintain and improve customer reliability and resiliency as more clean energy is added to the grid, provide more direct clean energy options for customers, and give customers more data and information for them to make the right decision for their individual power needs.

1.5. Demand Assessment and Investment Drivers

Eversource has made substantial advances in its advanced forecasting and modeling capabilities. For instance, Eversource now has the ability to project with hourly granularity the impacts of the Commonwealth's Clean Energy Climate Plans, thereby assessing their impacts on the local distribution systems. The Department's approval of Grid Modernization planning and forecasting tools, partnerships with MassCEC and with up-and-coming firms focused on developing analytical software, have provided the Company with the ability to forecast: (a) customer propensity to adopt rooftop solar; (b) economic growth of ground mounted solar using a combination of hosting capacity, land use permitting rules and costs; (c) customer adoption of electric vehicles and associated charging location and time periods; (d) new large customer connections in terms of locations, magnitude and uncertainty; and, (e) heating space demand at different weather conditions into electric demand with conversion to heat pumps. Eversource is able to overlay these projections onto existing hourly load shapes to recreate future hourly demand shapes resulting from the Commonwealth's policies – at a distribution feeder-level, geographically-targeted granularity. These innovations in advanced forecasting are a prerequisite to efficient EDC capital investment decisions by pinpointing where the constraints on the distribution system are projected to manifest.

The result of this in-depth forecasting and modeling is a projected 20% increase in net electric demand in the ten-year forecast period, raising the total peak demand in the Commonwealth served by Eversource from 6.1 GW to 7.4 GW.

The resulting headroom – endogenous to the forecast overlaid on the infrastructure capacity as well as internally consistent with the major bulk substation upgrades and associated implementation timeline – is translated into a kW per Capita available electrification hosting capacity in each municipality within Eversource's EDC territory. This electrification hosting capacity in each municipality can be further expanded into each community within a municipality – specifically larger cities like City of Boston that may have specific neighborhoods supplied by different large bulk substations. This information now equips city planners and policy makers to drive electrification programs into these communities to maximize clean energy deployment while also aligning with the capacity of the grid in those local distribution systems.

The Commonwealth of Massachusetts has outlined ambitious objectives to decarbonize by 2050 in its Decarbonization Roadmap. There are many different pathways to achieving these greenhouse gas (GHG) and net-zero emissions goals with varying impacts on the electric system. However, they all have in common an increase in demand on the electric system by unprecedented amounts due to supplying all the energy needs that are today being met through statewide gas infrastructure (i.e., liquid fuel distribution networks, and gas stations) via the electric power system. The base case shows the Company increasing its overall system electric demand from a 6.1 GW summer evening peak to a 15.3 GW winter morning peak by

2050. The majority of this 150% increase in electric demand by 2050 is driven by electrification of heating needs (about 50%) with the remaining driven primarily by electrification of transportation needs (25%) and normal load (25%). At a sub-regional level, the proportion of electrification impacts between heating and transportation vary. The Western region sees a higher proportion of transportation electrification demand relative to Metro Boston, resulting from longer average driving miles and associated charging demand. On the other hand, the Southeastern region sees a higher proportion of heating electrification demand relative to other regions due to a significant amount of commercial space and larger homes. The ten-year planned large bulk substations have a significant impact on increasing the electrification hosting capacity offset by economic development driven demand increase. This drives the Western Massachusetts region to be best positioned to enable electrification (at a regional level) followed by Metro West and then by SEMA. Despite significant new bulk substation additions in Metro Boston (documented within Section 6) and the associated 2 GW increase in electric demand hosting capacity if the infrastructure is deployed as planned, Metro Boston will only narrowly meet the regional electrification demand of 2050. In Metro West and Southeastern regions, Eversource still identifies approximately 1.7 GW and 1.6 GW capacity deficiency respectively needed to enable the full 2050 electrification future at a regional level. In Western Massachusetts, the 2035 bulk substation upgrades in the ten-year plan enable the full 2050 electrification future at a regional level. In addition, the Company projects another 2.4 GW of aggregated bulk station capacity will be required to interconnect the projected solar build out.

Additionally, this Section also includes the Company's forecasts of solar – geographic solar development considering land costs, interconnection costs in alignment with the Commonwealth's solar growth trajectory. The sub-regional solar forecasts are then layered in with available hosting capacities in these regions after the implementation of the ten-year plan. These granular sub-regional solar forecasts in turn inform the Company's planning framework to proactively upgrade the distribution infrastructure to enable solar above and beyond the interconnection queue.

Finally, because these forecasts – both solar and electrification – are so significant above and beyond the ten-year hosting capacity, the locationally-specific growth forecasts and associated pace of the growth are critical to informing the utility on where the bottlenecks will be and by when. This is why significant data-analytic and forecasting advancements have been put forth by the Company in building adoption propensity modeling approaches to deliver locationally specific forecasts.

Stakeholder Engagement and Feedback

Reliable electric service is vital to public safety, the health and welfare of the Commonwealth's citizens, and sustainable economic development opportunities. To promote a more resilient system and to properly plan for and address the Commonwealth's energy needs, clean energy infrastructure needs to be implemented in a timely manner. However, as Eversource transitions to this cleaner future, proposed utility investments must achieve both equity and clean energy objectives. Eversource believes these energy justice and reliability goals can be accomplished simultaneously and this balance will improve the Company's collective success in achieving shared clean energy goals. To ensure that Eversource operates under a common set of definitions, in Section 3, Eversource begins by defining Equity and adopting the state law definitions of Energy Benefits, Environmental Benefits, Environmental Justice, Environmental Justice Population and Meaningful Involvement.

Stakeholder engagement is foundational to a just and equitable energy transition and is at the core of how Eversource intends to develop projects associated with its ESMP. As the energy sector moves toward a cleaner energy future, the opportunities and challenges of this transition must be considered with a commitment to equity to maximize benefits for Eversource customers. This can only be done through deep and committed stakeholder engagement. To that end, Eversource has built an equity-focused =outreach plan that is based on the idea to build an engagement approach in partnership with stakeholders that have not historically participated in the project development and regulatory process, such as those customers living in environmental justice communities.

To help inform how Eversource can further enhance its stakeholder and community engagement, Eversource and its peer EDCs are proposing the development of a Community Engagement Stakeholder Advisory Group ("CESAG"), made up of representatives mutually agreed upon by Eversource and members of the GMAC. The primary objective of the new advisory group is to develop a Community Engagement Framework that can be applied to the new bulk substation ESMP projects documented in Section 6, before they are submitted to the DPU and/or the Energy Facilities Siting Board (EFSB). Eversource envisions this Community Engagement Framework will be co-developed and informed by key community-based organizations who have established trusting relationships in communities.

The Community Engagement Framework outlined in Section 3 will evolve and improve over time, leveraging lessons learned from real experiences. Eversource firmly believes that the recommendations outlined in Section 3 puts the Company on a path towards receiving comprehensive, diverse feedback that will lead to an inclusive set of ESMP activities that generate benefits in all communities across the Commonwealth.

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

As detailed in Section 7, the Company's ESMP provides a comprehensive view into the Company's five- and ten-year investment plans. Over the five-year period, the Company's existing plan calls for investing $4.5 billion in capital on electric operations, including peak load and capacity projects; and $1.0 billion on clean energy enablement, including AMI, CIP, and solar projects. In addition, the Company is proposing and additional $0.6 billion in new resiliency and technology platform capital investments. The Company's current plan includes $475 million in annual operations and maintenance expense for electric operations and operations support, $540 million in annual energy efficiency, electrification and demand response incentives, and is proposing additional operating expense with the implementation of new programs to enable DER to provide grid services. The Company's ten-year investment plan totals $12.1 billion with expenditures relatively flat year-over-year.

The outcomes resulting from these expenditures are diverse and impact all customers. In addition to these investments, the Company will also need to invest on the transmission system (and associated siting and permitting impacts) to supply the distribution infrastructure. The following is a summary of the benefits that will accrue as a result of the ESMP:

Safety. Every project to design, build or maintain an Eversource asset takes into consideration opportunities to keep employees and the public safe. Investments to replace aging infrastructure eliminate older equipment, such as antiquated oil switches that have a higher operational risk profile than the current technology. Other investments deploy equipment using equipment standards and work methods that adhere to the Company's rigorous guidelines to ensure worker and public safety.

Stakeholder transparency. A robust stakeholder engagement process will allow a diverse group of interested stakeholders to proactively engage and have a voice on a just transition to enable clean energy.

Grid reliability and resiliency. Reliability investments will drive improvements in the Company's existing reliability metrics. Further, as described in Section 10, the Company is proposing a new resiliency program to focus investment specifically on lessening the outage impact of major storm events and flooding. This program is targeting a 14% reduction in all-in customer minutes over ten years by investing in targeting undergrounding, vegetation management and overhead storm hardening.

Facilitation of the electrification of buildings and transportation. As a result of the plan, at the end of the ten-year period, the Company will have increased the headroom of the system to accommodate an incremental 2.5 GW of electrification load across its service territory. This effort will be complemented by the Company's energy efficiency and demand response programs that work to minimize loading from new and existing buildings. This work will be complemented by the Company's energy efficiency programs supporting not only the reduction in energy use but increased electrification and robust demand response programs. It will also be complemented by managed charging programs that minimizing the loading impact of electric vehicles added to the system. These programs will be coordinated with the Company's introduction of AMI as a tool to empower customers to actively participate in clean energy programs, including time-varying rates.

Integration of distributed energy resources. Eversource 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's existing and proposed CIP initiatives will add an incremental 1.0 GW of bulk station hosting capacity to enable DER interconnection. In addition, the Company's other non-CIP bulk station upgrades will add an additional 0.9 GW of hosting capacity. Other initiatives aimed at DER integration in the plan include the Company's proposals to support the use of DER to provide grid services.

Avoided renewable energy curtailment. The benefits described above related to DER integration will also help avoid renewable energy curtailment. With increased system capacity due to the Company's CIP and other system upgrades, there will be fewer instances where facilities trigger the need for extensive system modifications and thus the option to be curtailed due to voltage or capacity constraints. Further, as a part of its 2022-2025 Grid Modernization Plan, the Company is investing in dynamic DER interface technology that enables remote communication and control of customer DER facilities. With this technology deployed at a DER facility, operating agreements can be established that reduce the number of hours a facility will require curtailment.

Reduced greenhouse gas emissions and air pollutants. The Company's five- and ten-year plans allocated significant investment to initiatives that will directly and indirectly contribute to the Commonwealth's greenhouse gas emission reduction goals.

The following are Company investments included in the five-year plan that will directly and indirectly reduce greenhouse gas emissions:

- Eversource-owned solar.
- System efficiency and line loss reduction.
- Eversource operations.
- Energy efficiency and demand response programs.
- Investments to increase hosting capacity and enable DER.
- Encouraging DER as a grid service.
- Investments to increase headroom to support electrification of transportation and heating.
- Electric vehicle programs.

Avoided land use impacts. Eversource fosters the long-term vitality of the land it is a part of, and the Company promotes diverse native habitats through land management and preservation. Eversource's transmission, distribution and vegetation management divisions work to minimize the impacts of its operations on habitats that support a variety of species within its rights of way (“ROWs").

Minimization or mitigation of impacts on the ratepayers of the Commonwealth. Eversource recognizes the financial impact of electricity costs on customers. Working in four areas, the Company is working to minimize costs of its plan to ratepayers. First, the Company is minimizing costs of infrastructure with planning optimization. Second, the Company recognizes that planning the grid of the future will take multiple complementary approaches to ensure the most cost-effective solutions are implemented. Although there is an imminent need for system capacity driving the need for substation development, the Company is proposing to complement these projects with technology platforms and demonstrations to support the use of DER to provide grid services. This is a cost-effective solution, leveraging existing and new customer-owned DER in a VPP approach that uses assets deployed for other use cases to provide grid services. Third, the Company actively seeks out opportunities to empower customers to lower the energy usage to reduce costs. Eversource’s top-tier Mass Save energy efficiency programs for 2022-2024 are expected to have a total passive peak load reduction around 20 MW per year. This reduction directly reduces energy costs for participating customers. Once fully implemented in 2028, AMI technology will produce data and insights that can be utilized to create information and alerts for customers to be able to understand and manage their electricity usage and costs. Fourth, in addition to developing a comprehensive investment plan that meets the need for safe, reliable, resilient infrastructure that enables electrification and clean energy at the lowest possible cost, the Company supports efforts to ensure costs are equitably shared among ratepayers.

Improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources. One of the key transformational investments included in the Company’s five-year plan is the introduction of AMI for all residential and commercial electric customers. For customers, AMI will enable increased access to more granular usage information, improving the customer’s understanding of energy savings opportunities.

The Company’s sense of urgency to continue to maintain a safe and reliable service – is exemplified by the imminent capacity deficiencies in multiple areas which require upgrades to four bulk substations, all by 2024. The Company is already engaged in local community outreach efforts and petitions to the Energy Facilities Siting Board (EFSB) have either already been submitted or shall be imminently to ensure timely implementation of these urgently needed new bulk substations to maintain safe and reliable service.

Within the subsequent five years, (2025 – 2029) the Company will need to upgrade six bulk substations, construct five new substations, construct a new undersea cable to Martha’s Vineyard, and construct two Battery Storage systems in Hyde Park in Boston and Industrial Park in New Bedford to maintain safe and reliable service.

These bulk substation upgrades and additions by 2029, in aggregate, increase the electrification hosting capacity by 1.8 GW. This, in addition to the existing 7.9 GW firm capacity, results in the Company enabling 100% of the Commonwealth's 2030 goals at the aggregated bulk station level. Figure 3 below shows the Electrification Hosting Capacity above the 2030 forecasted peak, after implementation of the five-year Plan.

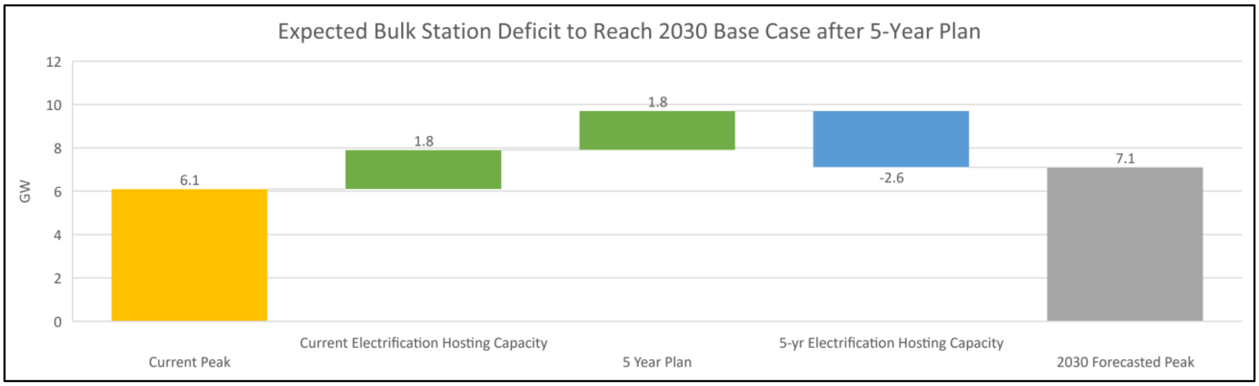


Figure 3: Expected Aggregated Bulk Station Capacity to Meet 2030 Forecasted Peak after 5-year Plan.

The full ten-year plan increases the electrification hosting capacity by an additional 1.6 GW to reach a total of 3.4 GW by 2034. Figure 4 below shows the aggregated bulk station capacity build up in the five- and ten-year plans, as well as the electrification hosting capacity above the 2035 Forecasted Peak.

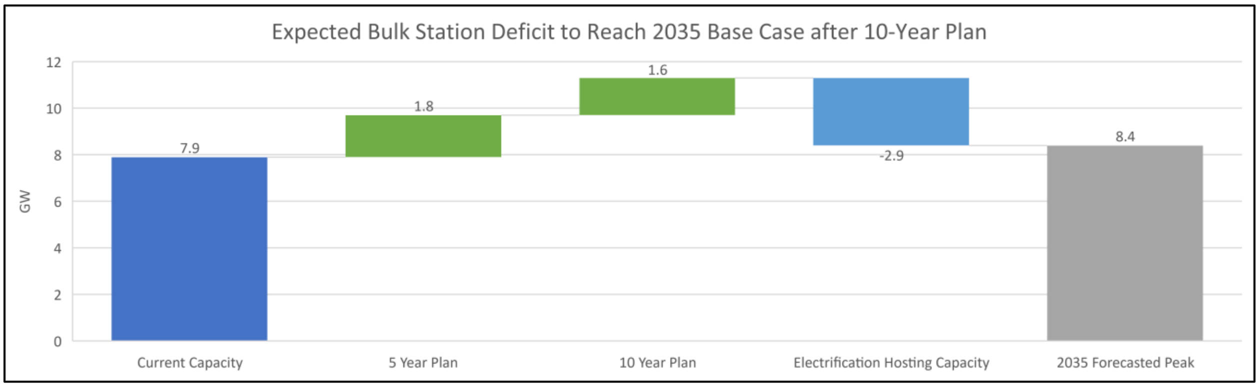


Figure 4: Expected Aggregated Bulk Station Capacity to Meet 2035 Forecasted Peak after 10-year Plan

While this shows significant Electrification hosting Capacity above and beyond the forecasted peak, the transition to a winter-peaking system and the associated rapid ramp up of load driven by heating needs, results in the ten-year plan enabling just over 50% of the Commonwealth's 2050 goals with an additional 4 GW of aggregated bulk station capacity required by 2050 to serve demand, as shown in Figure 5.

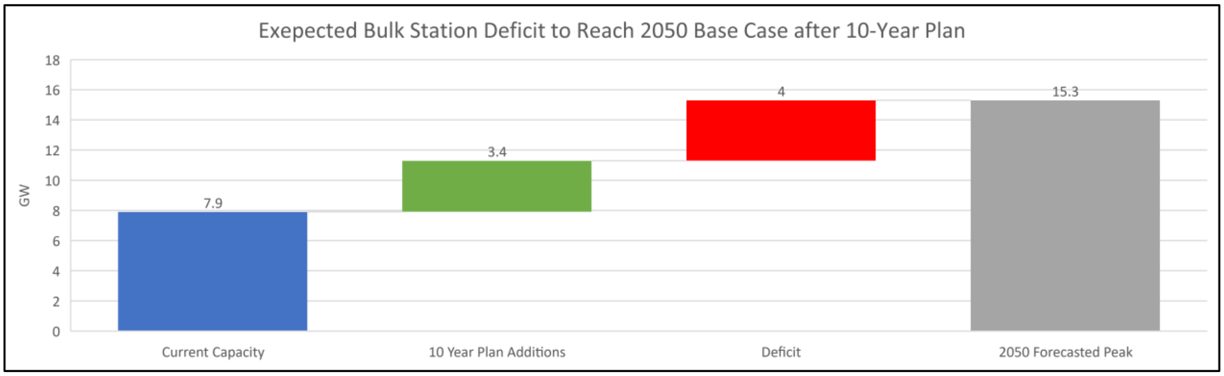


Figure 5: Expected Aggregated Bulk Station Capacity to Meet 2050 Forecasted Peak after 10-year Plan

The five-year plan includes (1) approved and (5) pending CIPs which, in concert with the aforementioned load-driven upgrades, enable an additional 1.1 GW of solar at a bulk station level or more than 100% of the Commonwealth's 2030 solar goals as shown in the Figure 6 below. The full ten-year plan enables an additional 1.2 GW of solar incremental to the five-year plan solar enablement, reaching 70% of the Commonwealth's 2050 goals at an aggregated bulk station level.

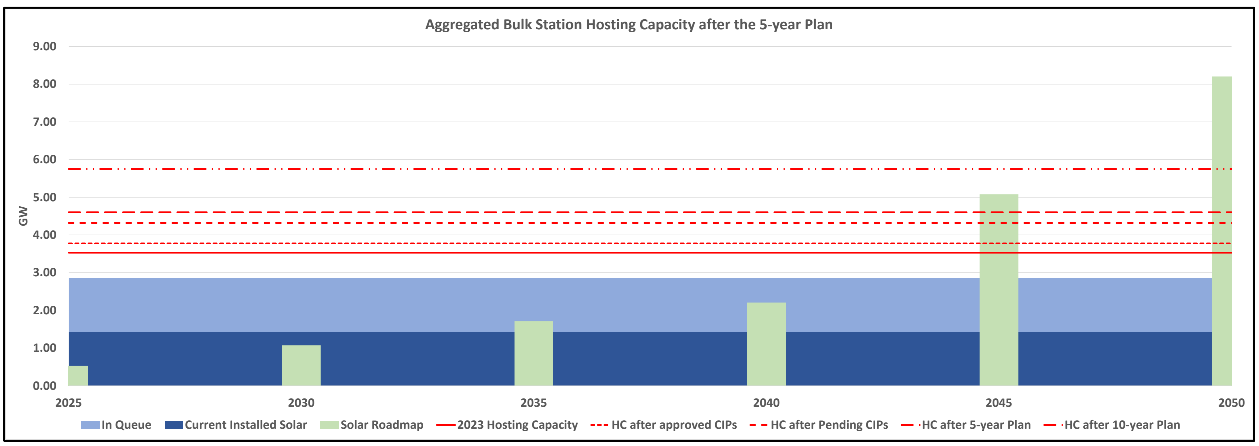


Figure 6: Expected Aggregated Bulk Station Hosting Capacity relative to the Commonwealth Solar Roadmap as allocated to the Company

Overall, to the extent the electrification and solar programs are coordinated with the grid capacity upgrades, the ESMP five-year plan enables 100% of the Commonwealth's 2035 clean energy goals. Across the Eversource territory, the available electrification headroom enables 2.5 million electric vehicles statewide and the equivalent of 1 million residential heat pumps by 2040.

The Company's five-year plan also includes $225M of Resilience hardening upgrades which include strategic undergrounding, rebuilding overhead lines, constructing new distribution lines and enhanced tree trimming and removal.

Building system capacity with substations and battery storage systems will provide a critical foundation for enabling electrification and reliable interconnection of DERs. A comprehensive and cost-effective total solution to address barriers to meeting the Commonwealth's clean energy objectives, however, must include technology platforms that support customer engagement and the use of DERs to provide grid services to increase flexibility and address local constraints. One of the most important foundational investments is the Company's deployment of AMI. By 2028, all customers will have greater insights into their usage information and more tools to engage in demand response and clean energy programs. To support the use of customer-owned DER as a grid asset, the Company is proposing investments that will enable the use of VPP technology to address system constraints and defer the need for system upgrades into the future where applicable.

1.7. Climate Impacts and Building Resilience

In the Company's Resilience Plan, Eversource introduces the Resilience Planning metric and associated data-driven Resilience Plan focused on vulnerable communities to ultimately reduce storm costs and improve customer service.

As noted previously, the Climate Mitigation Plans and Climate Adaptation Plans are interlinked from the customer standpoint. An electrified and clean energy enabled distribution infrastructure fails if it is not also designed to protect against extreme events driven by climate change.

Reliability: The Company's Base Reliability programs to replace aging and obsolete overhead, underground and substation equipment, and various programs to address poor performing circuits, serve as the bed rock of any utility programs for Eversource to continue to maintain top quartile reliability in the industry. Utility reliability performance metrics are commonly measured in terms of SAIDI, SAIFI and CAIDI. The Company commits to maintaining top quartile reliability by establishing industry leading targets and taking a data-driven approach to maintaining and improving reliability performance.

Resilience: The Company apportions a significant part of its Resilience Plan toward a comprehensive review of the Commonwealth's Climate Assessment and Hazard Mitigation and Climate Adaptation Plan. Eversource identifies a number of synergistic areas where it learns from the Commonwealth's identified vulnerabilities as well as commit to socializing the granular Company results with the various agencies to commence collaborative planning and a common understanding of shared risks. However, prior to considering future worsening climate conditions, the Company recognizes New England's current increased exposure to storms. New England was hit by three catastrophic storms since 2010 – Tropical Storm Isaias, Hurricane Sandy and Hurricane Irene. New England was also impacted by Winter Storm Alfred, also commonly known as the 2011 Halloween Nor'easter, which arrived just two months after Irene. When looking at 40 years of Storm data, these storms range between 1 in 30-to-50-year events. But shortening the lookback period to the most recent 15 years of storm data, suggests a dramatic compression in catastrophic storm probabilities in the range of 1 in 19-to-23-year events. This substantial compression in storm probabilities when looking at more recent storm history demonstrates that these catastrophic storms are becoming significantly more likely in New England. Within this ESMP, the Company is leading by developing a Resilience metric, to assess location and magnitude of vulnerabilities on the system, associated distribution system outages, but also unique hardening plans to address each damaged circuit at a device level granularity. Section 10 also includes the Company's methodology to maximize resilience benefits in the most cost-effective manner. Specifically, with the implementation of the ten-year plan, the Company projects a reduction in storm costs as well as quantifies reduction in customer cost of interruption. Given that these hardening investments would last well beyond thirty years, Eversource anticipates these benefits to grow especially considering future worsening climate conditions.

To meaningfully assess future value of resilience, the Company is now assessing the results of its Climate Vulnerability Study similar to the Commonwealth Climate Assessment. This study looks at Extreme Temperature Magnitude and Duration, Heavy Precipitation, Drought, Sea Level Rise and Storm Surge out to 2080 under two different Climate Change scenarios (SSP2 4.5 and SSP2 8.5). Coined as a middle of the road scenario by United Nations Climate Panel, the SSP2-4.5 scenario assume progress toward sustainability is slow, with temperatures rising by 2.7 degrees C by the end of the century with CO_2 emissions hovering around current levels before starting to fall mid-century but failing to reach net zero by 2100. By comparison, SSP2-8.5 scenario assumes global economic growth fueled by fossil fuels with a doubling of CO_2 emissions by 2050 and with temperatures rising by 4.4 degrees C by the end of the century. Specifically, the upper tail of the daily maximum temperature are projected to increase by 3.6F to 6.7F in Boston by 2050 and the upper tail of the daily average temperature are projected to increase by 3.7F to 7.7F in Boston by 2050. Both the average and maximum temperature projected increase supports a theory that this may be a new normal representation of blue-sky days' performance too. Under SSP2-4.5, the 50th percentile of the annual hottest daily temperature in Boston in 2050 is projected to be 100F, while under SSP5-8.5 the 90th percentile of the annual hottest daily temperature in Boston in 2050 is expected to be 103F. The Company is expecting about 5 to 7 heat waves annually by 2050, while the current baseline is about 2 heat waves annually. Additionally, those heat waves are projected to be much more prolonged by 2050. Under SSP2-4.5 50th percentile, the duration of the annual longest heat wave is expected to be 8-15 days in 2050, about double the current 4-7 days.

While the climate vulnerable study results were released in June and given the significant downstream changes this study will have on planning, new design standards, new construction standards as well as potentially new equipment designs, the timing of this ESMP filing does not provide the Company sufficient time to translate the results of the study into those specific proposed changes. However, given its criticality, the Company commits to proposing updates to its Distribution Planning and Design standards by the end of 2024. By the end of 2024, the Company plans to translate these Climate vulnerability study results into updates to its Distribution Planning and Equipment Design standards.

1.8. Workforce and Societal Benefits of a Just Transition

Each ESMP investment will lead to tangible benefits for both the workforce and the broader society, directly benefiting the residents with a special focus on residents of environmental justice communities of the Commonwealth. A clear focus of the Company is to engage with communities aiming to facilitate a transition towards long-term emission reduction goals in a fair and equitable manner. ESMP workforce and societal benefits include:

Economy, Jobs, and Training

The substantial investments necessary for the transition toward long-term emission reduction goals will result in positive economic benefits. Based on the United States Department of Commerce Bureau of Economic Analysis (“BEA”) Regional Input-Output Modeling System II (“RIMS II”), the Company forecasts that grid investments will result in significant positive economic benefits for the Commonwealth.[1] RIMS II is a regional economic modeling tool used by investors, planners, and elected officials to objectively assess the potential economic impacts of various projects. This model produces multipliers that are used in economic impact studies to estimate the total impact of a project on a region. The RIMS II methodology relies on the annual expenditure of program capital, accompanied by an associated economic benefit.[2]

The modeling forecasts $1.5 billion of incremental benefits over the first five years of the plan, with the state of Massachusetts poised to receive the significant portion of these benefits. For the extended timeframe of 2025-2035, these incremental benefits are expected to reach a total of $3 billion.

The RIMS II model also forecasts that ESMP investments will generate over 11,000 direct and indirect good paying jobs for Massachusetts residents in a wide variety of sectors from 2025 to 2030 and a total of more than 23,000 jobs during the extended period of 2025 to 2035 as a result of ESMP investments. Please see Section 12.4 for more details.

[1]“RMS II User Guide”, Bureau of Economic Analysis. US Department of Commerce, December 2013, https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf.

[2] The RIMS category is “Electric power generation, transmission, and distribution” and the multiplier is 1.244.

Those employment opportunities will include manufacturing, construction, engineering, maintenance, installation, grid operations, energy efficiency, consultancy, electric transportation, and research and development. As the grid is gradually able to host more renewable energy generation, the demand for skilled workers in the related industries increases, driving employment activities.

This transition will create good paying jobs for residents of the Commonwealth. To create equitable access to these job opportunities, the Company will work in partnership with environmental justice communities to create the pipelines for the grid workforce. Additionally, Eversource will continue to update its own training programs to reflect the training needed to build and operate the grid of the future, see Sections 7.3.3 and 12.2.3.

Technological Innovation, Research, and Leadership

The transition towards long-term emission reduction goals drives innovation in renewable energy technologies, energy storage solutions, and grid management systems including automation and microgrids. Utilities, private companies, and academic research institutions will invest in research and development to improve the efficiency, reliability, and affordability of clean grid technologies. These innovations will not only foster economic growth but also enhance the Commonwealth's competitive economic advantage.

Employment, Equity, and Environmental Justice

Being fully aware of the historical and disproportional impacts of pollution on environmental justice and other underserved communities, Eversource will engage with these communities to address their concerns on the transition to devise an equitable process for all, as described in Section 3. Eversource will continue to develop and promote hiring and workforce development programs, in partnership with the community and other stakeholders, that will benefit environmental justice communities and the Commonwealth's workforce at large; please see Sections 12.2-3. Although substantial investments are needed for this transition, the long-term benefits include less reduced reliance on imported fossil fuels and greater energy efficiency. Being fully cognizant that affordability is a major concern among customers, the Company will target LMIs and environmental justice communities' residents for its programs such as training, energy efficiency, electric vehicles, and solar.

Health Benefits

A tangible benefit of the ESMP is a significant reduction in emissions in the state of Massachusetts, directly associated with reducing various health concerns. Eversource's electric vehicle program will tackle emissions from the transportation system. The deployment of enhanced Volt-Var Optimization ("VVO") with AMI technologies is expected to lower energy consumption and emissions in the state. Additionally, the Company's solar programs save significant amount of carbon emissions. Eversource supports Energy Efficiency programs aimed at delivering green and healthy homes characterized by improvements in indoor air quality. Installation of air-source or ground-source heat pumps in communities that do not currently have access to air conditioning space, would realize tangible benefits in terms of health outcomes especially in communities disproportionately impacted with asthma and heat related illnesses.

Improvements in electric reliability will benefit customers who depend on electricity for their medical devices. As outages disproportionally impact environmental justice communities, reducing them will be a step in addressing environmental and health inequities, see Section 12.5.

Eversource is fully engaged in facilitating the transition towards long-term emission reduction goals within the Commonwealth as required by the Massachusetts statutes. In addition to the previously mentioned emission reduction strategies, the Company's dedication to minimizing its emission footprint across all operational levels is underscored by investments in innovative technologies. Notably, the development of breakers without Sulfur Hexafluoride ("SF6") – the most potent greenhouse gas - highlight this commitment. Eversource will strive to maintain its leadership in decarbonization and will continue to innovate and invest in new grid technologies that will bring tangible workforce and societal benefits for a just transition.

1.9. Conclusion and Next Steps

Eversource is committed to being a catalyst for a cleaner, more inclusive energy future. This ESMP presents the Company's comprehensive roadmap to enabling the environmental, health and economic benefits of decarbonization and climate change mitigation for all Massachusetts communities, with a focus on delivering positive outcomes in historically marginalized communities. Eversource has crafted this ESMP with a realistic and detailed plan clearly established for the next five and ten years and a vision for the steps that will be needed to meet decarbonization targets by 2050.

The Company believes as a general rule that the public engagement process should be robust and that proactively soliciting feedback is critical. In the period following the submission of this ESMP 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 findings and recommendations. Furthermore, Eversource is committed to at least two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. In addition, and as discussed previously, the Massachusetts EDCs are jointly proposing the CESAG to further inform their engagement efforts around the proposed projects in Section 6 of their respective ESMPs. Finally, as discussed in Section 13, Eversource in collaboration with the other EDCs will propose ESMP metrics and a reporting template for stakeholder review and comment prior to submitting the ESMP to the Department in January 2024. The metrics and corresponding reporting template will be designed to support transparency and accommodate mid-term modifications based on GMAC and stakeholder feedback prior to submission of the Company's next ESMP in 2028.

2.0 Compliance with the EDC Requirements Outlined in the 2022 Climate Act

Section Overview

The Company's ESMP 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. Eversource 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 (Sections 4.3.9, 4.4.9, 4.5.9, 4.6.9 and 10.0 on reliability and resiliency and Section 6.3 on communications); (ii) enable increased, timely adoption of renewable energy and distributed energy resources (Sections 6.1 and 7.1); (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy (Sections 7.1, 8.0, and 9.0); (iv) prepare for future climate-driven impacts on the transmission and distribution systems (Section 10.0); (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, the transmission system (Sections 6.0, 8.0, and 9.0); and (vi) minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the Commonwealth realize its statewide greenhouse gas emissions limits and sublimits under Chapter 21N (Sections 7.1 and 9.0).

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 ESMP describes in detail each of the following elements, as required by G.L. c. 164, § 92B(b): (i) improvements to the electric distribution system to increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks (Sections 4.3.9, 4.4.9, 4.5.9, 4.6.9 and 10.0); (ii) the availability and suitability of new technologies including, but not limited to, smart inverters, advanced metering and telemetry and energy storage technology for meeting forecasted reliability and resiliency needs, as applicable (Sections 6.3 and 9.0); (iii) patterns and forecasts of distributed energy resource adoption in the Company's territory and upgrades that might facilitate or inhibit increased adoption of such technologies (Section 5.0 and 8.0); (iv) improvements to the distribution system that will enable customers to express preferences for access to renewable energy resources (Section 9.0); (v) improvements to the distribution system that will facilitate transportation or building electrification (Sections 7.1, 8.2, 8.3, 9.1.1, 9.1.2); (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under Chapter 21N (Sections 7.1 and 9.0); (vii) opportunities to deploy energy storage technologies to improve renewable energy utilization and avoid curtailment (Sections 4.3.5, 4.4.5, 4.5.5, 4.6.5, 5.1.6, 9.1.4, 9.5.2); (viii) alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response (Sections 7.1.1, 9.1 and 9.5); and (ix) alternative approaches to financing proposed investments, including, but not limited to, cost allocation arrangements between developers and ratepayers and, with respect to any proposed investments in transmission systems, cost allocation arrangements and methods that allow for the equitable allocation of costs to, and the equitable sharing of costs with, other states and populations and interests within other states that are likely to benefit from said investments (Sections 7.1.2 and 9.5). Additionally, the Company's ESMP identifies customer benefits associated with the investments and alternative approaches including, but not limited to, safety, grid reliability and resiliency, facilitation of the electrification of buildings and transportation, integration of distributed energy resources, avoided renewable energy curtailment, reduced greenhouse gas emissions and air pollutants, avoided land use impacts and minimization or mitigation of impacts on the ratepayers of the Commonwealth (Sections 6.3.1, 7.1.3, 12.0).

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 (Section 5.0), a 10-year forecast (Section 5.0) and a demand assessment through 2050 to account for future trends, including, but not limited to, future trends in the adoption of renewable energy, distributed energy resources and energy storage and electrification technologies necessary to achieve the statewide greenhouse gas emission limits and sublimits under Chapter 21N (Section 8.0). G.L. c. 164, § 92B(c)(i). The Company also considers and includes a summary of all proposed and related investments (Section 7.1), alternatives to these investments and alternative approaches to financing these investments (Sections 7.1.1 and 7.1.2) that have been reviewed, are under consideration or have been approved by the Department previously. G.L. c. 164, § 92B(c)(ii). Finally, the Company has submitted this plan and solicited input, such as planning scenarios and modeling, from the Grid Modernization Advisory Council established in section 92C, responded to information and document requests from said council and conducted technical conferences and a minimum of 2 stakeholder meetings to inform the public, appropriate state and federal agencies and companies engaged in the development and installation of distributed generation, energy storage, vehicle electrification systems and building electrification systems (Section 3.0). G.L. c. 164, § 92B(c)(iii).

2.3. Planned Investments

The Company's ESMP, in Section 6 describes discrete, specific, enumerated investments and alternatives to meet the statewide greenhouse gas emissions limits and sublimits under Chapter 21N through enabling a just transition to a reliable and resilient clean energy future. The proposals focus on the 5-year and 10-year horizon, while also discussing the policy drivers and groundwork needed for future investments and alternatives in 2035-2050. While many of the proposals in the 5- to 10-year timeframe focus on utility assets that are specifically needed for near-term increases in demand, the Company envisions the 2035-2050 solutions set will integrate significant incentive design scenarios that will incorporate meaningful developments in demand response, load management, and other aggregated or system-wide approaches. For all planned investments and alternative approaches, the Company has identified 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 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 Company's customers. The Company also considers how the proposed investments will impact the workforce, the economy overall, and the population's health.

3.0 Stakeholder Engagement

Section Overview

Reliable and resilient electric service is vital to public safety, the health and welfare of the Commonwealth's citizens, and sustainable economic development opportunities. To promote a more resilient system and properly plan for and address the Commonwealth's energy needs, clean energy infrastructure needs to be implemented in a timely manner. However, as Eversource transitions to this cleaner future, proposed utility investments must achieve both equity and clean energy objectives. For everyone to benefit from a clean energy future, economic and cultural barriers must be overcome to ensure impacted communities have a seat at the table when key decisions are being made. Eversource believes energy justice and reliability goals can be accomplished simultaneously and that this balance will improve Eversource's collective success in achieving Eversource's shared clean energy goals.

Eversource is committed to being a strong environmental partner, a responsible neighbor in the communities it serves and to ensuring all stakeholders are afforded effective and equitable opportunities to access, participate, and benefit from its proposed projects. This commitment requires Eversource to build and maintain trusted partnerships through meaningful community engagement and incorporate feedback in Eversource's decision-making processes, especially from those who are burdened with existing negative environmental circumstances and justice disparities.

This stakeholder engagement and partnership is foundational to a just and equitable energy transition and is at the core of how Eversource intends to develop projects associated with its Electric Sector Modernization Plan (ESMP). As the energy sector moves toward a cleaner energy future, the opportunities and challenges of this transition must be considered with a commitment to equity to maximize benefits for Eversource's customers. This can only be done through deep and committed stakeholder and community engagement. To that end, Eversource has built an Equity-Focused Plan, that is based on an engagement approach in partnership with community stakeholders, with an emphasis on stakeholders that have not historically participated in the project development and regulatory process, such as those customers living in disadvantaged communities.

Eversource's stakeholder engagement is focused on engaging with all communities Eversource serves in ways accommodating to them based on their needs, not Eversource's assumptions. This includes acknowledging and emphasizing those communities historically burdened by decisions out of their control and are likely the greatest impacted by climate change. To help inform how Eversource can further enhance its stakeholder and community engagement, Eversource is proposing the development of a Community Engagement Stakeholder Advisory Group ("CESAG"), made up of representatives mutually agreed upon by Eversource, the other Electric Distribution Companies and members of the GMAC. The primary objective of the new advisory group is to develop a Community Engagement Framework that can be integrated when implementing new clean energy infrastructure projects specifically documented in Section 6.5.1, before they are submitted to the DPU and/or the Energy Facilities Siting Board (EFSB). Eversource envisions this Community Engagement Framework to be co-developed and informed by key community-based organizations who have established trusting relationships in communities. Relationships with these key community representatives and organizations can help the Company to prioritize the incorporation of the voices and lived experiences of those customers they represent.

The Community Engagement Framework will evolve over time, leveraging lessons learned from real experiences and accomplishments. Eversource firmly believes that the recommendations outlined in Section 3 puts the Company on a path towards receiving comprehensive, diverse feedback that will lead to an inclusive set of ESMP activities that generate benefits in all communities across the Commonwealth.

3.1. Background & Definitions

As the Commonwealth works to decarbonize its energy system, Massachusetts has taken significant steps over the years to codify in the law, the important role environmental justice will play in the transition. Eversource recognizes that as it moves towards a cleaner energy future, the opportunities and challenges of this transition must be considered with a commitment to equity so that benefits can be shared across all customers.

The recent 2021 Climate Act, among other drivers, defines environmental justice populations (or environmental justice communities), environmental burdens and environmental benefits, and directed Commonwealth agencies to develop processes and standards that would ensure participation by members of Environmental Justice communities. Shortly following the passage of this bill, the Executive Office of Energy and Environmental Affairs (EEA) also updated its Environmental Justice Policy in June 2021.

To ensure that this document operates under a common set of definitions, it begins by defining 'Equity' and adopting the state definitions of Energy Benefits, Environmental Benefits, Environmental Justice, Environmental Justice Population and Meaningful Involvement.

3.1.1. Definitions:

When referring to common terminology throughout this plan, it's important to level set to ensure there is a clear understanding by all parties of how Eversource defines important terms.

While there is no definition for “equity” codified in state law, Eversource defines equity as the following:

Equity: engaging all stakeholders, including Eversource’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.

Eversource also adopts the following definitions from 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.

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: 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 Population: 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.

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.

3.2. Eversource Equity Framework

Eversource developed a set of engagement principles as part of its Equity Framework (first communicated in the Company's rate case D.P.U. 22-22) that underpin the Company's actions to solicit feedback on major projects and communicate major actions going forward and the basis of Eversource's ESMP stakeholder efforts. The Equity Framework was developed by Eversource as a multipronged strategic approach to serving customers with an intentional focus on environmental justice communities to enable equitable outcomes for all communities and customers served by Eversource. The Equity Framework is a deliberate initiative to increase engagement and communication with historically marginalized communities.

Specifically, Eversource's Equity Framework is guided by the following relevant principles as it relates to stakeholder engagement:

- Actively solicit and value stakeholder input and engagement through routine incorporation into projects and services.
- Collaborate with stakeholders to achieve mutually positive outcomes for Eversource projects and programs.
- Work to achieve fair and just outcomes for all Eversource's stakeholders (especially with respect to communities burdened with economic challenges, racial inequity, negative environmental impacts, and justice disparities), and ensure that Eversource reasonably mitigates any potential negative community outcomes that may arise as a result of Eversource activities.
- Ensuring Eversource's stakeholders and communities that are served feel respected and that Eversource's work supports their dignity.

3.3. ESMP and Equity-Focused Stakeholder Engagement

As Eversource prepares to construct clean energy infrastructure projects (documented in Section 6), a critical component is to ensure that there are significant energy and environmental benefits of the projects – specifically, enablement of reliable and resilient heating and transportation electrification and adoption of renewable generation in alignment with the Commonwealth's CECP. The ESMP projects may additionally contribute to increased grid resiliency in EJCs through better alignment of the commonwealth's clean energy programs with the electrification hosting capacity resulting from the construction of the large new bulk substations or by more proactively targeting these communities for enhanced vegetation management and prioritizing resiliency upgrades in EJCs to address climate change impacts. Alignment of the commonwealth's clean energy programs with increased electrification hosting capacity in communities – especially those that host the new large bulk substations, will further pave the way for more renewables and clean energy electrification in these areas. Proactively soliciting feedback on these types of proposed projects will be paramount in ensuring successful outcomes.

Overall, Eversource's approach is summarized in Figure 7 below and described in subsequent sections.

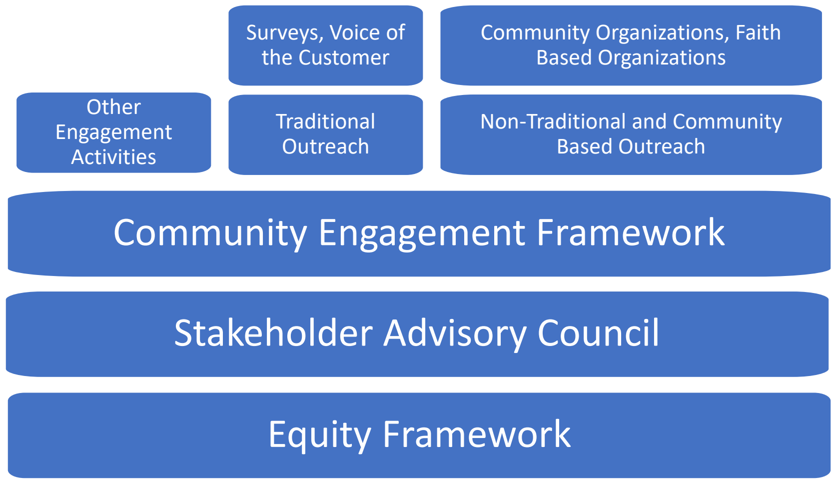


Figure 7: Community Engagement Approach

The proposals in this section have been developed to not only leverage Eversource's current Equity Framework by continuing to have a strong focus on EJCs but also expanding engagement efforts to cover all potentially impacted stakeholders, as it is vital that future engagement strategies are developed with input from those stakeholders.

3.4. Outreach and Information Gathering from Key Stakeholders

As Figure 8 below illustrates, there are a myriad of different stakeholders that are integral to the energy sector transformation and that are potentially impacted by the implementation of ESMP projects. Eversource plans to identify key stakeholders and conduct outreach to engage them in the ESMP stakeholder process.

Figure 8: Key Clean Energy Stakeholders

Of these groups identified, there are several stakeholders of key importance for advancing equity, including customers, community-based organizations, and environmental justice advocates. This section provides more insight into these key stakeholders and unique engagement considerations.

3.4.1. Customer Outreach

Listening directly to customers is at the heart of Eversource's strategy to implement its ESMP goals and solicit feedback. To address and prevent unconscious bias, Eversource will listen to customers and communities without judgment, to gain a better understanding of their needs, concerns, and challenges.

One way in which Eversource currently listens to its customers is through its Voice of the Customer (VOC) organization. The VOC organization is focused on designing and executing strategies to obtain customer insights and communicating those insights broadly to internal business partners. The insights identified guide the design and analysis of Eversource's customers' experiences delivered by Eversource. Existing customer engagement includes digital surveys, voice surveys, focus groups and other channels for gauging customer satisfaction.

The VOC organization is currently in the field with a survey targeted at residential customers, with an oversampling of low-income customers and customers that live in EJCs, to gauge customer's attitudes towards clean energy. The goal of this survey is to help the Company better understand how customers feel about clean energy, their willingness to adopt clean energy products, and their feelings towards Eversource actions to enable additional clean energy. This survey is just one example of how Eversource solicits feedback from customers.

Conducting surveys help the Company develop a baseline understanding of customers' preferences and attitudes towards programs and initiatives. When conducting surveys or customer outreach, it's essential to take steps to ensure communications are clear and helpful to all customers in a specific community. An example of a strategy that Eversource uses to improve effectiveness within communities, is understanding the languages spoken and knowledge of message delivery preferences, both of which are examples of critical components to building effective, two-way communication with Eversource's customers.

Through discussions with GMAC members and other community-based organizations, Eversource developed an initial customer outreach survey to further inform the Company about Eversource's customers' current understanding of the Clean Energy transition and help to shape future education and outreach materials as a result.

3.4.2. Municipal Outreach

Eversource has ongoing engagement with local governments and has continuous interactions with local leaders, including mayors, selectmen, city and town managers, boards and commissions regarding the delivery of safe and reliable service to Eversource's customers.

Engaging and deepening relationships with local leaders is a critical part of the ESMP process and essential for collaboratively and successfully executing Eversource's Future Grid/Climate Ready Grid plan. Local communities want to be a part of the decision-making process when choosing infrastructure locations. They want to understand the 'why' and 'what' and then be involved in the determination of the 'where' and 'how'.

The infrastructure investment needed to reach clean energy goals will occur at the local level, which requires close coordination with Eversource's municipalities on community outreach and engagement around specific projects, obtaining local permits and permissions to do work in municipal rights of way and streets, and ensuring that construction timelines are such that they don't interfere with or complicate major municipal priorities, including the municipalities' own infrastructure work.

These same municipalities are also Eversource's 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, Eversource's towns and cities have economic development goals and housing needs.

To better engage with and understand the interests of each of Eversource's towns and cities and their constituents, Eversource engages in direct dialogue with municipal leaders, including individual mayors and energy managers. Eversource also engages with municipalities through organizations and existing partnerships. The Company's approach is to actively engage with municipal officials and key stakeholders to educate and garner feedback.

3.5. Environmental Justice Communities

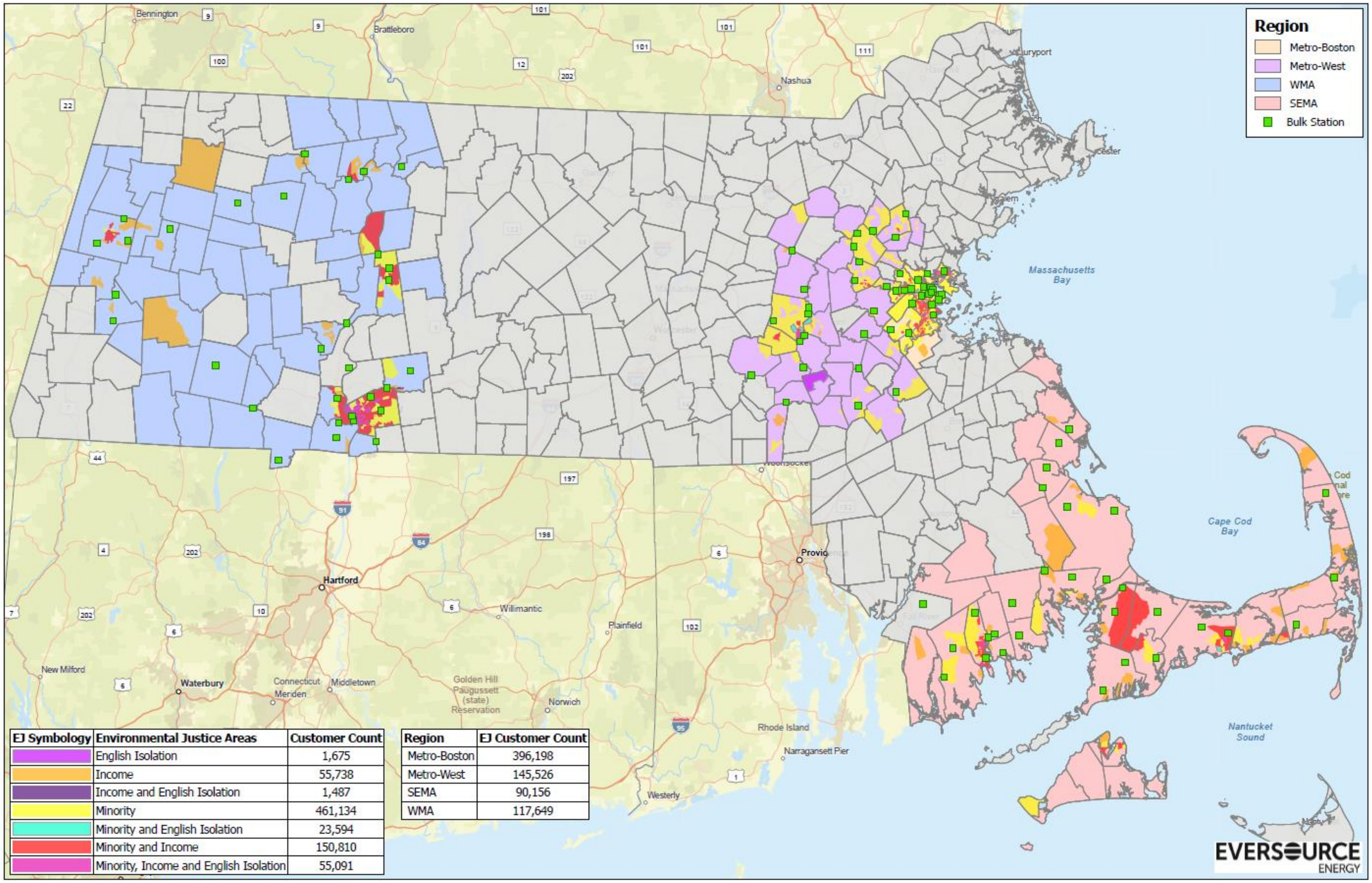
Eversource aims to take a leadership role to address overt and covert inequities and bias in communities. Eversource is uniquely positioned to engage with disadvantaged communities and, with their help, identify opportunities to improve service and outcomes. Engagement requires an understanding of and respect for the historical inequities and ongoing disparities facing many, particularly those communities that are home to Black, Indigenous and People of Color (BIPOC) who often are environmentally burdened and economically challenged. Eversource is committed to increasing engagement with Eversource's customers, with an intentional focus on underserved and environmental justice communities.

Eversource's commitment to equity, as codified in the previously referenced Equity Framework, includes an explicit obligation to improve Eversource's communication's effectiveness with historically marginalized communities.

Eversource firmly believes that the path to environmental justice starts with recognizing and understanding historical inequalities and ongoing disparities and listening to the voices of Eversource's most vulnerable customers and communities. This approach helps guide us on the tools to use, experiences and events to participate in, and resources available to ensure Eversource's customers and communities feel informed, understand the personal benefits of Eversource's work, and know how to engage in the process.

All outreach in EJCs will be done in part by identifying languages spoken in stakeholder communities in order to enhance strategic communication with multilingual customers. Language identification data shall be used to inform and secure interpreters, generate appropriate translations of materials, conversations, dialogue, and in-community events. And whenever possible community meetings shall be scheduled during late afternoon/evening hours and/or weekends as further described below. This is all being done to rectify historic inequities and will govern the various ways Eversource engages with stakeholders.

Figure 9 below shows the location of each EJ block in each region o Eversource's service territory and the number of customers in each EJ block. Section 4 includes more discussion on the distribution of EJ customers within each region with relation to teh electrical infrastructure.



EJ Symbology	Environmental Justice Areas	Customer Count
	English Isolation	1,675
	Income	55,738
	Income and English Isolation	1,487
	Minority	461,134
	Minority and English Isolation	23,594
	Minority and Income	150,810
	Minority, Income and English Isolation	55,091

Region	EJ Customer Count
Metro-Boston	396,198
Metro-West	145,526
SEMA	90,156
WMA	117,649

Figure 9: Eversource Service Territory Mapping to Environmental Justice Communities

3.6. Stakeholder Meetings and Information Exchange

3.6.1. Ongoing ESMP Fall Workshops

Eversource and the other electric distribution companies (EDC) are committed to hosting two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. These workshops are critical to ensuring there is stakeholder engagement and feedback gathered. These workshops will be conducted in the following manner:

- Stakeholder attendees will be pre-determined in consultation with the GMAC.
- Professionally facilitated.
- All workshops will be hosted virtually, at times recommended by the GMAC or Equity Working Group, with language translation services.
- Used as an opportunity to further educate stakeholders and gain feedback from the voices of the community.
- The EDCs will track all recommendations and develop a formalized feedback loop for increased transparency.
- All recommendations will be shared with the GMAC.

3.6.2. Proposed "Community Engagement Stakeholder Advisory Group" ("CESAG")

In addition to the two fall workshops, to further inform EDC engagement efforts around proposed clean energy infrastructure projects from Section 6, the EDCs are proposing the development of a new **Community Engagement Stakeholder Advisory Group ("CESAG")**. The CESAG will allow for a structured opportunity for the EDCs to develop a comprehensive stakeholder engagement and community benefits agreement framework that will enable a) increased transparency and stakeholder understanding of the complex electrical grid and EDC distribution planning process through establishment of a repeatable community engagement platform and b) ensure communities that host new bulk substations and associated transmission infrastructure directly benefit from this clean energy enablement infrastructure. The CESAG will help to ensure that historic obstacles to stakeholder engagement such as language barriers or the location/time of engagement sessions are addressed to ensure the widest possible level of community participation.

3.6.2.1 Members and Meeting Frequency:

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

- Once the frameworks are established, periodic review of these frameworks would be conducted.
- Frequency of future meetings would be determined by the CESAG as applicable.
- Meetings will be professionally facilitated.

3.6.2.2 Community Engagement Framework

To meet the objectives of the Commonwealth laid out in An Act Driving Clean Energy and Offshore Wind, it will be critical to build new distribution infrastructure to accommodate higher penetrations of clean energy and electrification. This new infrastructure needs to be built relatively quickly in order to meet the Commonwealth's overall decarbonization goals and the near-term interim Clean Energy and Climate Plan emissions reduction targets. Given the need to execute all ESMP projects, the first mandate of the proposed CESAG would be to develop a Community Engagement Framework that can be used by the EDCs as an overall guide to working with all potential impacted communities and stakeholders prior to projects (from Section 6) going before the Energy Facilities Siting Board. This framework will be co-developed and informed by a partnership between the EDCs and key community-based organizations. At its core, the EDCs are providers of safe and reliable energy. As Eversource continues to build and enhance Eversource's community engagement efforts, it is important the EDCs remain informed by the voices of these communities. This goal will be furthered 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 EDC community engagement framework would enable the following:

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

The goal is for the EDCs to follow a framework co-developed with community partners to allow for greater community understanding and support around projects in Section 6. This will help expedite critical projects necessary as part of the ESMP to accelerate decarbonization in the

Commonwealth. As the EDCs continue to learn and grow in this space, the CESAG can continue to identify ways the EDCs can adjust outreach and engagement strategies in response to feedback from partners, allies, and communities.

3.6.2.3 Community Benefits Agreement Framework

To ensure that communities that host clean energy infrastructure directly benefit from the infrastructure, a connection between the clean energy enablement infrastructure and the clean energy programs is necessary. Such community benefits agreements can take shape with the feedback from CESAG stakeholders to ensure EDCs continue to re-think and formulate new methods and approaches to drive benefits of this just transition to the appropriate communities.

3.7. Stakeholder Input and Tracking

Eversource is not only committed to taking proactive steps to promote community involvement and engagement during the planning of large projects but also committed to providing a transparent feedback loop regarding all input received in the engagement process.

Reaching out to communities and community members early and often, through their desired channel, is a key tactic to solicit feedback before project plans are fully finalized. It is critical for Eversource to receive this feedback, so project plans and their associated impacts aren't based solely on Eversource assumptions but on real feedback from the community affected. Further, it is equally important for Eversource to meaningfully address the input received from its communities and explain how that input factored into decision making.

This type of engagement is geared towards making the process of implementing the ESMP more transparent and increasing Eversource's accountability to impacted stakeholders.

These steps include:

- Inclusive outreach expanded to specifically provide information to and gather feedback from EJ communities affected by the project.
- Collaborative discussions about solutions to mitigate the impacts of project construction and potential burdens of additional infrastructure with community betterment measures that align with regulatory parameters.
- Timely responses to the affected stakeholders, including civic associations, community-based organizations, and the affected municipality.
- Detailed analyses and action plans to ensure that the proposed project appropriately addresses potential impacts to the environment and community through avoidance and minimization approaches.

Increasing the ability to understand the needs of the communities Eversource serves and to track and monitor program participation historically by community — and in real time — helps us understand what has or hasn't been successful and make data driven appropriate changes.

Eversource is committed to regularly assessing Eversource's approach and course-correcting as needed. Continuous and regular stakeholder input will ultimately help Eversource improve operational and corporate processes, systems, and practices to better understand and serve the needs and unique circumstances of customers.

3.8. Key Takeaways from Stakeholder Engagement

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

Reaching out to communities and community members early and often, through their desired avenue, is a key tactic to solicit feedback before project plans are fully finalized. It is critical for Eversource to receive this feedback, so project plans and their associated impacts aren't based solely on Eversource assumptions but on real feedback from the community. Eversource is committed to meaningfully address the input received from its communities and explain how that input factored into decision making.

3.9. Future Stakeholder/Community Engagement Process

Throughout all stakeholder engagement, Eversource will use an equity lens to account for different opportunities and burdens experienced within communities, with the goal of pursuing equitable solutions to achieve system level change. By using this approach, it will be possible to support more and diverse public participation in energy planning and decision-making while also advancing equity and broadening equitable outcomes for all of Eversource's customers.

Stakeholder input is a critical component for Eversource's successful implementation of the ESMP as it helps augment investment and operating activities. This is done by proactively listening to communities to balance equity, resiliency, and affordability. Acknowledging the competing priorities of Eversource's work while seeking to balance equitable outcomes for Eversource's customers becomes a critical variable in all operational decision making.

3.10. Ongoing and New Proposed Stakeholder Working Groups

The CESAG described above can help offset potential issues and concerns raised by local communities around the inclusion and awareness of utility filings. The CESAG would develop a community engagement framework that would begin the stakeholder engagement process before any projects were brought before the EFSB. The goal of this early engagement is to help ensure those stakeholders and communities most impacted by Eversource projects in Section 6, are heard and part of the process.

For all future community meetings related to the projects in Section 6.5.1, Eversource is committed to hosting meetings with the following principles in mind:

Why:

- Pivotal for Eversource to meaningfully engage with communities and stakeholders with the shared goal of not only recognizing and understanding the potential historic burdens faced by a community but also to educate that community about a potential need for and benefits of a project.
- This education has to be multidirectional both for the community to learn about Eversource system needs, and for Eversource to better understand the community's needs and how Eversource can help to mitigate as many impacts as possible of a potential project or program in that community.

Who:

- Solicit input from all types of stakeholders, especially those with relevant lived experiences, in addition to technical experts.
- All neighborhoods who might be impacted by a project should be engaged.
- Impacted stakeholders may want to engage directly through Eversource, or alternatively through community organizations, religious institutions, or other municipal organizations.

Where:

- Community meetings should be held in the neighborhoods where the project will be located or impacted.
- They should take place in community-oriented locations, ones that are commonly used for community events.
- Community meetings should take place near public transit stops so that transit riders can attend.
- Meetings should, whenever possible, be held in a hybrid format providing both an in-person and virtual option. Remote-only meetings may present barriers to participation for residents with limited internet or electronic devises, while in-person-only meeting

may present a barrier for residents who have disabilities, small children, are immunocompromised or constrained by work schedules.

When:

- Initial community meetings should begin during the project planning process.
- Schedule community meetings during different times of day and different days of week for maximum participation.
- Whenever possible community meetings should be scheduled during late afternoon/evening hours and/or weekends.

How/What:

- Eversource must both communicate in the spoken and written languages of the community and understand the ways in which customers in each community want to be communicated with.
- Written materials and presentations should not include acronyms.
- Any technical language should be written and spoken in a way so that residents who do not work in the field of energy generation, transmission or distribution can easily understand.
- All materials, including notices, slides, handouts should be translated (written form) into the languages spoken in the neighborhoods.
- Meetings in a hybrid format should be recorded and easily available for later viewing. Additionally, the hybrid format aligns with the Commonwealth's re-authorization to allow public bodies to host remote meetings, and the public's expectation of a virtual option.
- All meetings should also provide simultaneous interpretation (verbal form) into the languages spoken in the neighborhoods where the project is being proposed and where the meeting is taking place.
- Multilingual staff whose primary job is not translation/interpretation should not be asked to translate/interpret unless they are certified translators/interpreters and are compensated accordingly.
- Outreach should include notices and flyers publicized in commonly used medium including local newspapers (including multilingual newspapers), social media, local TV channels, churches, senior centers, schools, community centers and other community organizations and gathering spaces.
- Community meetings should include food for meeting participants.
- Providing childcare also allows for a more expansive list of possible attendees to attend community meetings with their children.

As noted above, communicating in the spoken and written languages of the community is critical for effective engagement. In addition to understanding the appropriate written and spoken languages, it is equally important to understand the ways in which customers in each community want to be communicated with. Impacted stakeholders may want to engage directly through Eversource, or alternatively through community organizations, religious institutions, or other municipal organizations.

4.0 Current State of the Distribution System

Section Overview

Eversource distribution systems can be broadly segmented into four sub-regions: Eastern Massachusetts (EMA)-North Metro Boston, EMA-North Metro West, Southeast Massachusetts (SEMA) and Western Massachusetts (WMA). Each sub-region has its unique sets of challenges for which the EDCs must develop planning solutions. Metro Boston and Metro West have seen a significant increase in electric demand driven by each region's success in key business areas such as life sciences laboratories as well as broader economic growth that surpasses most regions in the nation. Metro Boston is also exposed to an elevated risk of coastal flooding due to climate change. In the past decade, Eversource has only constructed three new bulk distribution substations in Metro Boston and Metro West – one in the Seaport district of Boston, one in the town of Brighton and another in the Longwood Medical area. Due to the pace of economic growth surpassing the pace of construction of large new distribution infrastructure upgrades, the available distribution capacity headroom has rapidly diminished. This has accelerated the need for construction of four new bulk substations and expanding four existing bulk substations by 2029 in the Metro Boston and Metro West regions to continue to maintain a robust and reliable electric service, especially in the light of future electrification needs. Additional details on adjacent substation capacity deficiencies ameliorated with these new bulk substations is included in Sections 4 and 6.

While the greater Boston region is experiencing capacity deficiencies due primarily to significant load growth, the Southeastern region has seen a significant growth in distributed energy resources (DER), primarily solar photovoltaic (PV) generation and PV combined with battery energy storage systems (BESS). The current installed solar in conjunction with queued interconnection requests, have reached 55% of peak demand in the Southeastern region. The impacts of high penetration of inverter-based, variable generation on the system lead to capacity constraints resulting from reverse power flows during off-peak hours and voltage issues on the distribution system. This has accelerated the need to not only construct or expand eight bulk substations in the region but propose alternative cost allocation mechanisms to equitably distribute costs of infrastructure upgrades based on benefits derived not just by solar developers but by distribution customers broadly. Upgrades to these bulk substations coupled with transmission upgrades would enable about 1 GW of clean energy from solar PV on local distribution systems in southeast Massachusetts to be supplied via the transmission system into distribution systems in Metro Boston and Metro West load centers. The Cape region of Southeastern Massachusetts is also particularly exposed to high wind speeds during storms, necessitating hardening upgrades focused on this subregion discussed further in Section 10.

The Western region has also seen a significant growth in solar PV with current installed plus queued interconnections reaching 63% of peak demand in this region. Additionally, this region was designed to supply power to geographically distant customers through very long, exposed overhead distribution lines, typically over 20 miles. This exposure leaves these lines vulnerable to many common outage causes. With additional impacts due to climate change, the need to harden these distribution systems is even more urgent. These systems will be hardened through a combination of strategic undergrounding, creation of new bulk substations to reduce the distribution line risk exposure and rebuilding of overhead structures.

While upgrades to the distribution systems to increase capacity are critical to enable a reliable transition to a decarbonized future, there are other existing distribution system capital programs that are necessary to continue to maintain safe and reliable service to Eversource's customers. Extensive reliability programs ensure that the aging infrastructure continues to be upgraded using quantitative data-driven approaches to inform efficient replacement decisions. Investments in technologies support real-time operation of the grid, including communications infrastructure, outage management systems and geographic information systems to maintain asset data.

The Massachusetts electric distribution system is at an inflection point. Over the past eight years, Massachusetts has led the nation in its response to the climate crisis by making unprecedented commitments to reducing green-house gas (GHG) emissions attributable to the state. In 2017, Massachusetts closed the last coal-fired power plant in operation in the state, Brayton Point. In 2020, Massachusetts became one of the first states in the country to establish a Net Zero emissions limit. In addition to expanding clean energy production, the Commonwealth has consistently ranked among the most energy-efficient states in the nation.[3]

Over the past five years, much of Eversource's service territory in Massachusetts has seen significant economic growth, especially the Metro Region around Boston, driven by the region's business development in areas such as life sciences laboratories. Economic growth is forecasted to drive ten percent growth in peak electric demand in Eversource's Massachusetts service territory between 2023 and 2032, compared with relatively flat peak load growth system-wide over the previous decade. Approximately three quarters of this projected growth, and associated capacity concerns impact the City of Boston and the

[3] Commonwealth of Massachusetts. "Commonwealth Clean Energy and Climate Plan for 2050." Massachusetts Department of Energy Resources, Dec. 2022

metropolitan area surrounding the city.

In the past decade, Eversource has only constructed three new bulk distribution substations in the Commonwealth – one in the Seaport district of Boston, one in the neighborhood of Brighton and another in the Longwood Medical area. Bulk distribution substations convert power from transmission-level voltages to distribution-level voltages. The pace of economic growth has surpassed the pace of construction of new large distribution infrastructure upgrades, rapidly diminishing the available distribution capacity headroom. This has accelerated the need for significant upgrades to the Electric Power System (EPS) to continue to maintain a robust and reliable electric service, especially in the light of future electrification needs.

While the greater Boston region is experiencing capacity deficiencies due primarily to significant load growth, other regions of the system, such as SEMA and WMA, are challenged by significant growth in distributed energy resources (DER),[4] primarily solar photovoltaic (PV) generation and PV combined with battery energy storage systems (BESS) which produce direct-current (dc) output that needs to be converted to alternating-current (ac) output via inverters to be supplied to the grid. High penetration of this inverter-based, variable generation on the system has led to capacity constraints during off-peak hours and voltage issues on the distribution system. These challenges must be addressed to provide safe reliable service for all customers because large front-of-the-meter (primary connected) solar installations are not geographically coincident with metropolitan load centers. In locations geographically distant from load centers, the expansion of large Bulk Distribution Substations will facilitate reverse power flow (from distribution system onto the transmission system) enabling renewable DER energy to supply excess power into the transmission system. In this way, substation expansions will contribute to rapid retirement of fossil fuel generation. With the growth in DERs expected to accelerate due to state incentives and newly approved cost allocation methodologies,[5] significant upgrades to the EPS must be constructed to facilitate the transmission of clean energy from where it is produced to where it is consumed.

Within the West region of the state, reliability issues manifest due to higher outage exposure of long, overhead, radial distribution lines (900 to 1,000 miles of reinforced three-phase lines emanating directly from substations, also known as backbone feeders) running through heavily treed areas due to the lack of bulk distribution substations in sparsely populated

[4] DER or DG, refer to any type of facility that must submit an application under a Distribution Company's DG Interconnection Tariff, regardless of whether it actually generates electricity (e.g., energy storage systems). Department of Public Utilities. "D.P.U 20-75." 22 Oct. 2022

[5] Provisional System Planning Program Guide," Mass.gov. For more details, visit Provisional System Planning Program Guide | Mass.gov

areas. This inherent design, combined with the fact that in all regions, major system components, such as transformers, poles and wires are rapidly approaching end of useful life, increases reliability risk for customers. This increased outage exposure is further exacerbated by the increased frequency and intensity of catastrophic storms resulting from climate change. Despite these challenges, the Eversource MA system reliability metrics, SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index), are typically in the first quartile of the IEEE benchmarking survey (see Section 4.1.9). For example, 2022 top-quartile SAIDI performance was lower than 90 minutes (blue sky), SAIFI was less than 0.84 and CAIDI less than 106 minutes. By comparison, in MA, Eversource's performance was 58.9 minutes of SAIDI, a SAIFI of 0.62 and a CAIDI of 94.3 minutes, i.e., all three blue-sky metrics were within top quartile for 2022. There are areas of the Company's Massachusetts system where customers suffer less than first-quartile reliability. The reliability performance per division is shown later in this Section under the "Reliability and Resilience Performance" subsections. Against the backdrop of worsening impacts of climate change, Eversource is focusing its hardening plans in areas where performance is consistently worse than the Commonwealth's average reliability and resilience performance.

With the growing needs and deficiencies, as discussed later in this Section and in Section 6, Eversource is taking an integrated planning approach to identifying planning criteria violations and system constraints and developing solutions that address the key challenges affecting the distribution system today, over the next ten-years, and through 2050.

4.1. State of the Distribution System and Challenges to Address

4.1.1. The Electric Power Grid – An Overview

Near the end of the millennium, the National Academy of Engineering named the electric power grid as the greatest achievement of the 20th century due to its impact on the quality of life over the previous 100 years, powering almost every pursuit and enterprise in modern society. The basic architecture of the grid (shown in Figure 10 below) has not changed much since that pronouncement; Most generation is still central generating stations whether they be gas, hydro, nuclear, etc., connected by high-voltage networked transmission lines which move electrons from the power plants to substations, which step voltage down to local distribution systems,[6] which ultimately deliver power to businesses and homes (primary and secondary customers).

However, the mission and challenges facing the grid and the impact on customers have significantly evolved over the past decade. Even though most generation resources are still central power plants feeding into the transmission network, there is still significant retirement of traditional generation sources (like coal and gas plants) replaced by expansion of inverter-based technology including significant growth in offshore wind, transmission connected large solar farms and Distributed Energy Resources (DERs) such as Solar PV feeding into both the transmission and distribution systems.[7] Figure 11 below is a simplified version of the distribution system showing how it has evolved to accommodate new technologies such as generation from wind farms and large solar plants, grid-scale energy storage, electric vehicles (EV), and rooftop solar and local battery energy storage in customers' residences and businesses.

Acting as an interface between the transmission system and customers, the distribution system serves as the backbone of a reliable Electric Power System (EPS). An effectively planned distribution grid, especially as Eversource's customers transition to an even more electrified future, is therefore critical to providing the essential safe and reliable electric service directly to customers.

---

[6] The distribution system is defined as substation, feeder, and equipment operating at voltages below 69,000 Volts (or 69kV) and above 4kV. The distribution system serves as a bridge between the electric transmission system (typically at 115kV) and the low-voltage system supplying customers (typically voltages below 460V).

[7] Inverter-based technologies are triggering significant changes to the way the distribution system is modeled and analyzed. Instead of focusing solely on static analysis at hourly intervals, distribution analysis has evolved to transient analysis at the milli-second scale. Study methods have also transitioned from snapshot analysis at the peak-load hour during an entire year to evaluating all 8760 hours of the year. This is because with PV and battery storage, the constraints on the system are no longer just on specific summer or winter peak days, but it could be early mornings, nighttime, winter, spring, or fall.

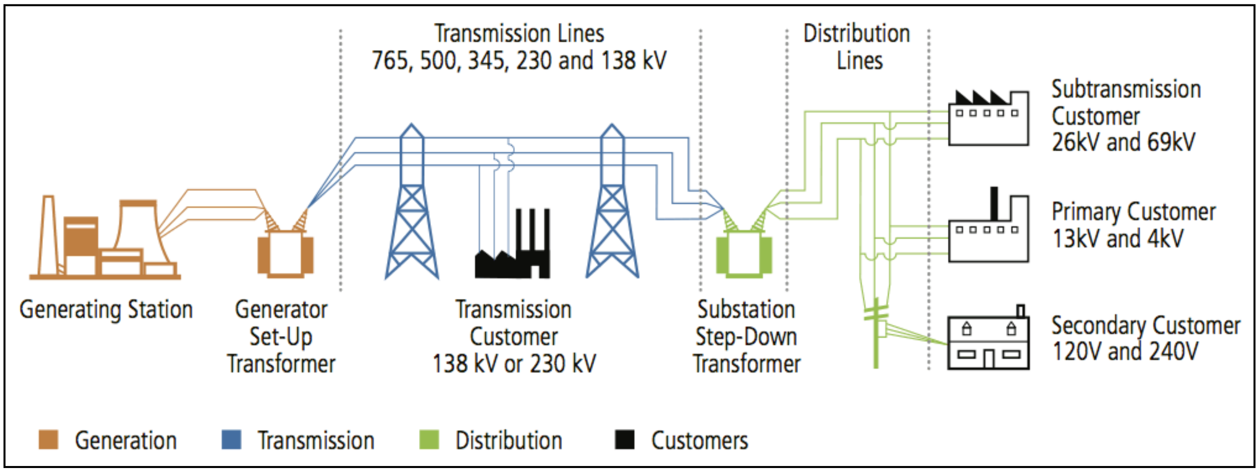


Figure 10: Basic Architecture of the Electric Power Grid (Source DOE - Quadrennial Energy Review)

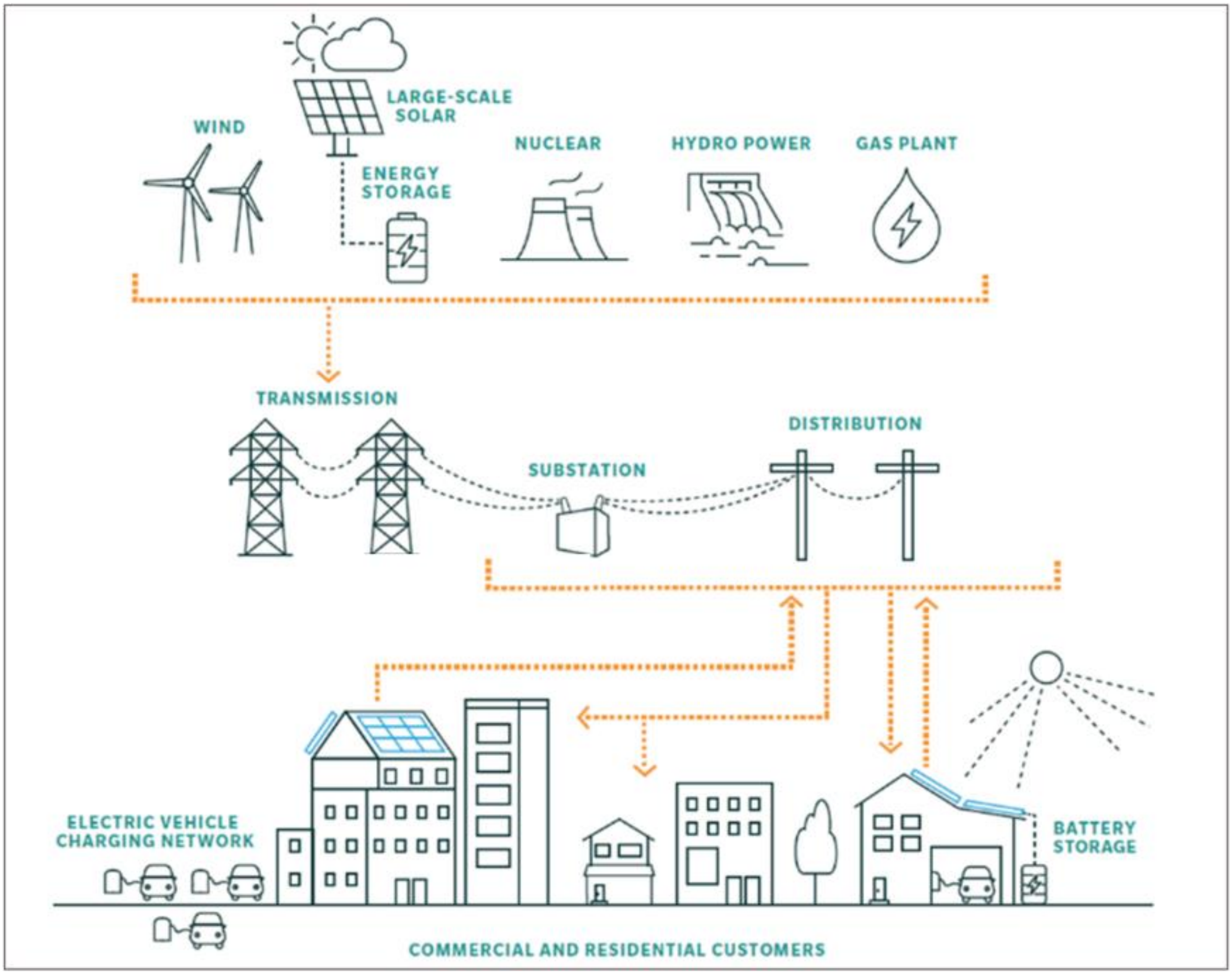


Figure 11: Basic Architecture of the Evolving Electric Power Grid

4.1.2. The Company's Power Grid – An Overview

The Company's electric distribution system includes the following major assets:

- 172 substations
- Approximately 11,500 circuit miles of overhead lines
- 9,200 circuit miles of underground lines
- 172,900 service transformers

Integral to the provision of safe, reliable service to all customers, load and DER alike, are Bulk Distribution Substations, also defined as those substations directly supplied from the transmission system.

The Company's 1.47 million electric residential, commercial, and industrial customers require approximately 6 GW of peak electric demand. Bulk Distributions Substations,[8] supplied directly from the transmission system, are integral to the provision of safe, reliable service to all customers. Bulk distribution substations vary in size and complexity based on customer needs and the geographic area supplied. At their core, bulk distribution substations all serve the same function – step-down high (transmission) level voltages, typically 115 KV, to lower level (distribution) voltages, typically 13 kV, 14 kV or 23 kV, that are more practical for routing power locally to supply customers or interconnecting DER. Other than reliable conversion of transmission current and voltage to distribution current and voltage and vice-versa in areas where DER energy exceeds distribution customer consumption, Bulk Distribution substations do not serve any other function – but serve as a path to transmit clean energy. More specifically, Bulk Distribution substations do not themselves emit air pollutants or greenhouse gases. With the retirement of fossil fuel generation on the transmission system replaced by large solar and offshore wind, these Bulk Distribution substations serve a critical purpose of transforming current and voltage from distant transmission connected renewable generation to local distribution systems and conversely transform current and voltage from renewable DERs on the local distribution system to the distant load center distribution systems with the help of the transmission system. 72,600 DER projects totaling over 1.9 GW are supplied and interconnected by 101 bulk distribution substations. This power generated locally is carried by the transmission system to other, distant bulk distribution substations, which supply load centers via distribution lines. As customers replace their fossil-fuel based appliances and cars with electrified technologies, these bulk distribution substations are critical facilities needed to transform

[8] The distribution side of bulk distribution substations is supplied by multiple transformers that step-down transmission level voltage (typically 115-kV) to distribution level voltage. All the transformers at a single bulk distribution substation are connected via 14-kV bulk distribution bus-work. This 14-kV bus is the source for all 14-kV distribution feeders emanating from that substation.

current and voltage from distant located renewable generation transmitted through the transmission system into local distribution systems to reliability provide the current and voltage necessary to power these customer-sided electrified technologies.

Figure 12 below[9] shows the approximate location of Company's 101 bulk distribution substations shaded by Planning Region (see Section 4.2 for a description of Planning Regions). In aggregate, these substations currently have a total firm capacity to serve 7.9 GW of customer demand. With the current peak customer electric demand of 6.0 GW, in aggregate, the distribution system has an available headroom of 1.9 GW. Having said that, because these bulk distribution substations serve local townships, it is the capacity of an individual bulk distribution substation relative to the customer electric demand at that local township that is more relevant to the available headroom. A more detailed representation of local headroom will be explained further in this Section below.

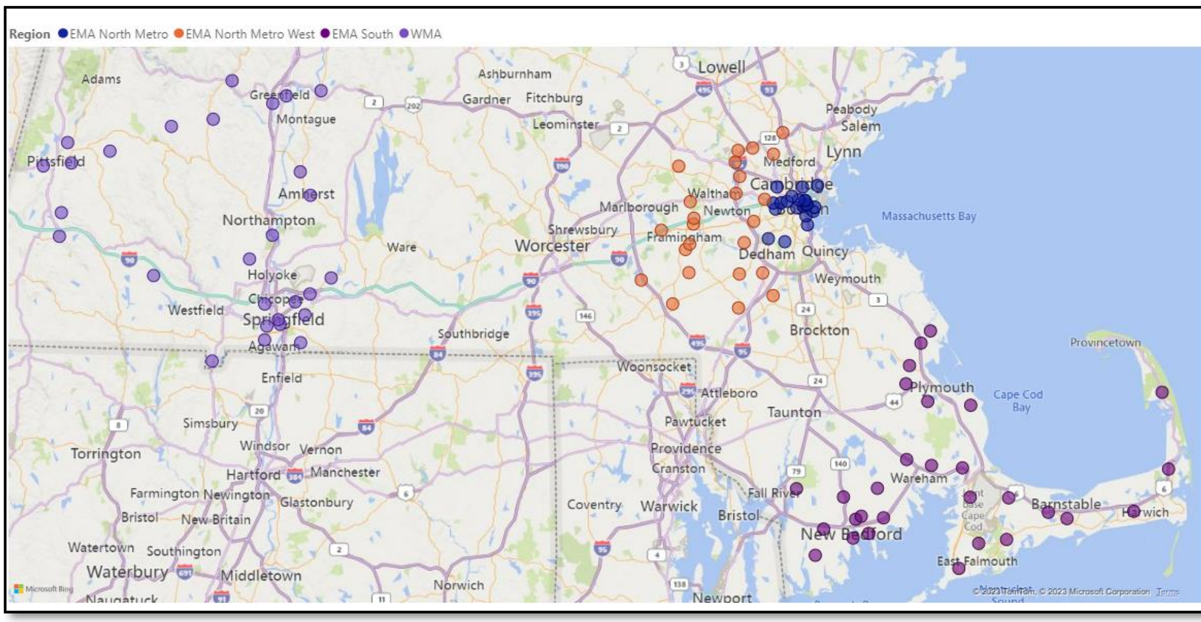


Figure 12: Location of Eversource bulk distribution substations in Massachusetts

Electric distribution systems are designed to move power from substations to customer loads (or from DER to loads) in the most efficient manner possible. Several (sometimes conflicting) factors determine the nature of the design, including size of the load, distance to load, system voltage level, topography, etc. Ultimately, the laws of physics and electric service standards dictate whether a service configuration is practical and/or possible. For this reason, the

[9] Refer to the Massachusetts Executive Office of Energy and Environmental Affairs 2020 Environmental Justice Populations Map overlaid with the approximate location of the Company's 101 bulk Distribution substations.

Company strategically places substations near load centers and defines a service area for each substation based on the ability of distribution feeders, operating at their voltage level, to move power from the source to loads while maintaining adequate service quality. The number of substations required to serve customer load and their locations depends on a number of factors, but load density or the number of customers and total MW (megawatts) per square mile is one of the primary drivers for the number of substations necessary to serve that load level, their size (in terms of number of transformers installed and total capacity), and their proximity to each other.

Figure 13 below shows typical areas with increasing load densities: a residential street, a significant portion of a city, and a dense urban area. The figure shows that as the population density increases for the same geographic area (typically in square miles), the amount of needed equipment capacity[10] increases. Applying these factors to the Company substation map in Figure 12, it can be clearly seen that dense load areas such as Metropolitan Boston, the City of New Bedford, and the City of Springfield require more substations per square mile with more and shorter distribution feeders due to the significantly higher load density. Conversely, rural areas with much lower load density such as areas of Plymouth, Cape Cod, and Western Massachusetts require fewer and smaller substations, located further apart, and with longer distribution feeders to serve sparser load.

Another factor determining the number and density of substations is the operating voltage of the distribution system. A distribution system operated at 23kV can serve approximately twice the amount of load as a 13kV or 14kV distribution system, with feeders approximately twice as long, with fewer bulk distribution substations. Areas of the Eversource service territory, such as Plymouth, Cape Cod, and portions of Western Massachusetts, which operate at 23kV, require fewer substations to serve the same amount of load compared to Boston or New Bedford, which have 13 and 14kV distribution systems. The distribution voltages in each area of the Eversource service territory were selected many years ago in the early stages of development of the electric power grid and are not easily changed due to the interconnected nature of local distribution systems. Conversion of a local distribution system to a higher voltage would require a complete overhaul of all substation equipment and distribution cables, incurring a significant investment. At this point, Eversource does not view this as necessary to enable electrification. Nevertheless, some lower (obsolete) voltages, such as 4kV, are being phased out over time, and

---

[10] Equipment capacity, such as power transformers, is measured in Volt-Ampere (VA), a thousand Volt-Ampere is 1KVA and a million Volt-Ampere is 1MVA. Small residential transformers installed in overhead poles typically range in size from 25kVA to 100KVA. Medium size residential pad-mounted transformers installed on the sidewalks or inside customer property are typically in the range of 50kVA to 500kVA. Large residential transformers installed below grade or inside customers buildings range in size from 500KVA to 2.5MVA.

where justified, the Company makes an effort to convert voltages to standard values to ensure service reliability and secure operation.

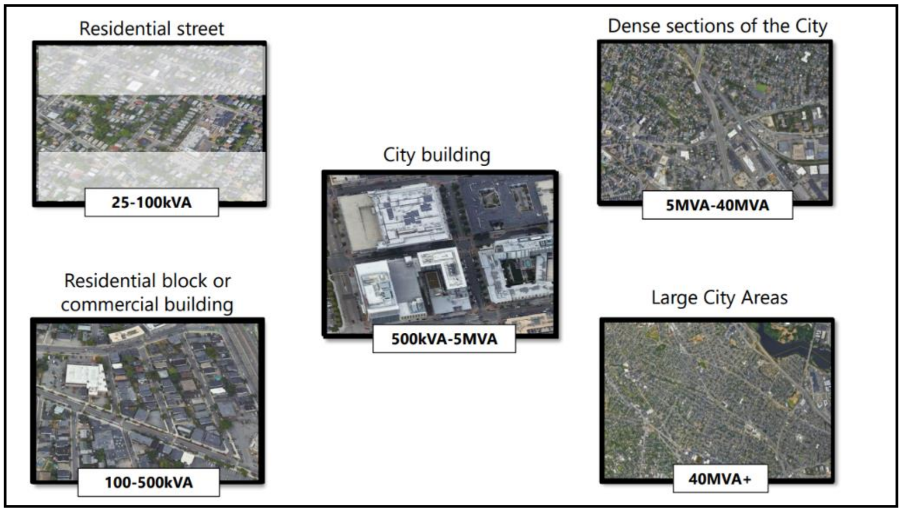


Figure 13: Examples of Areas with Different Load Densities

4.1.3. Bulk Distribution Substation Overview

Bulk distribution substations are key components of the electric power system, essential elements in meeting consumer demand for energy and supporting 21st century economies as discussed earlier. Eversource views bulk distribution substations as clean energy hubs that create the necessary headroom on the electric system to accommodate future system demand and electrification supply, and are therefore a critical element of the Company's ESMP. Figure 14 shows a typical bulk distribution substation with incoming high voltage transmission lines, (typically 69kV, 115kV and 345 kV), terminating at high voltage buses, power transformers which step voltage down to distribution levels (typically 13 kV, 14 kV, 23kV or 27kV) and outgoing distribution feeders. This differs from a "generating station" where power is "generated" or created. The fact that a bulk distribution substation serves a power conversion function, via static equipment such as transformers that does not move or rotate, as opposed to a power generation function illustrates that a distribution substation is a "greener" asset (with no greenhouse gas emissions generated) than most forms of generation assets. In fact, bulk distribution stations are agnostic to the source electrons that flow through them, and as such, are critical for moving wind power, solar generation, or any form of clean energy from source to consumers.

Figure 14: Bulk Distribution Substation

The major components of a bulk distribution substation include:

- One or more stepdown power transformers, which reduce or "step down" the incoming 115kV transmission voltage to primary distribution voltage. Electrically, this is no different than the smaller size pad-mount transformer located on the street from which residential service lines emanate – stepping down the primary distribution voltage to the 120 Volts that most residential appliances are powered with.
- Circuit breakers, which provides protection during abnormal conditions for the substation equipment and the distribution feeders that emanate from the substation. Electrically, this is no different than the smaller breakers inside the breaker panel in every residential home that protect the wires from burning out in case of a short-circuit or fault.
- Bus-work, which 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.
- A Protection and Control room which houses electronic equipment that needs to be protected from the environment.
- Incoming transmission line(s), which supply the bulk substation from the transmission system.
- Outgoing primary distribution feeders, which may be either overhead or underground, which supply the street circuits that supply the distribution transformers located on a street which in turn serve customers directly – no different than different wires that

supply different rooms and associated outlets within a residential home (albeit much smaller size wires)
- A fenced area surrounding the substation for protection of the station equipment and for protection of the public and animals.

A bulk distribution substation may be of an "open air" (AIS, or Air Insulated Substation) design with individual freestanding bus-work and circuit breakers or may be a metalclad "enclosed" design with all bus-work and breakers inside an enclosure – no different (albeit much smaller) than a breaker panel box inside residential homes which contain multiple breakers.

The topology and arrangement of a bulk distribution substation depends upon the reliability requirements, load magnitude, and load density of the area being supplied. Historically, Eversource predecessor companies constructed substations using single bus/open breaker arrangements with each transformer supplying each bus section. This was adequate for lower load densities and expectations for electric reliability that prevailed at the time. With load density and DER penetration increasing, higher expectations for electric reliability, and a desire to increase system resilience, Eversource has standardized on two substation bus topologies (shown in Figure 15 below) for future construction:

1. Double bus/double breaker switchgear (for low to medium load density areas). Each substation transformer and each distribution feeder will be fed from two primary bus sections through two feeder breakers. An outage of a bus section or any individual element will not result in customer load loss.
2. Ring bus arrangement (for medium to high load density areas). The switchgear will be arranged in a ring bus so that an outage of any bus section or any individual element will not result in customer load loss. A ring bus offers higher system reliability than a double-bus/double breaker arrangement. With all transformers in parallel this may require series reactors for fault current mitigation.

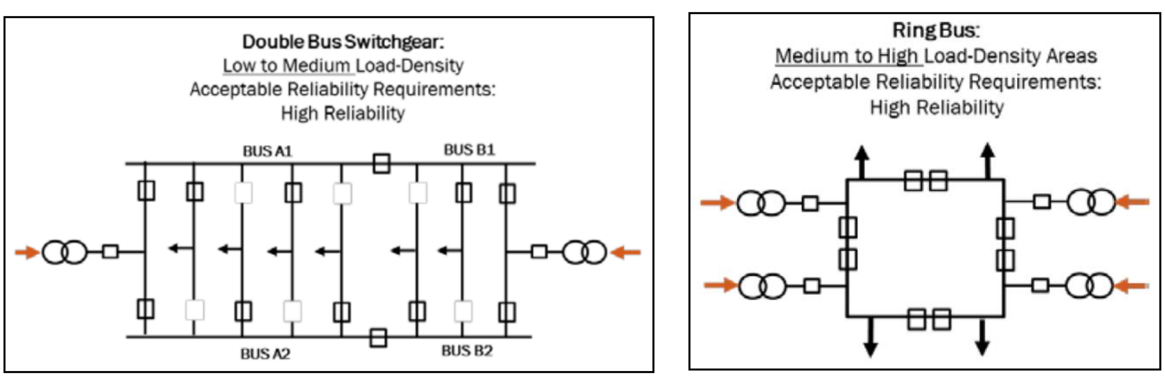


Figure 15: Eversource Standard Substation Designs

4.1.4. Planning Challenges

Across the Eversource MA service territory, there are diverse challenges to the planning mission. Figure 16 shows the service territory, highlighting challenges with respect to load and DER in different areas. In the Western portion of the state where load is characteristically low and developable land is available, Eversource anticipates the need to build distribution capacity to accommodate future DER growth. Most of the electrical load is in the population centers of the North (Metro Boston and Metro West), but due to space constraints and other factors, there are limited locally installed generation resources. Eversource expects this trend to expand further with future electrification of transportation and the heating sector, leading to an approximately 50% increase in total electric demand in Metro Boston and Metro West region by 2035. Conversely, in the Southeastern region with a current peak demand of 1.2 GW, Eversource has seen significant growth in DER resources (over 650 MW online and 1.3 GW in the queue) and anticipate connection of 6.4 GW of offshore wind injection in this region during the same time period – by 2035 – significantly accelerating the need to expand the Transmission and Distribution systems in the Southeastern region.

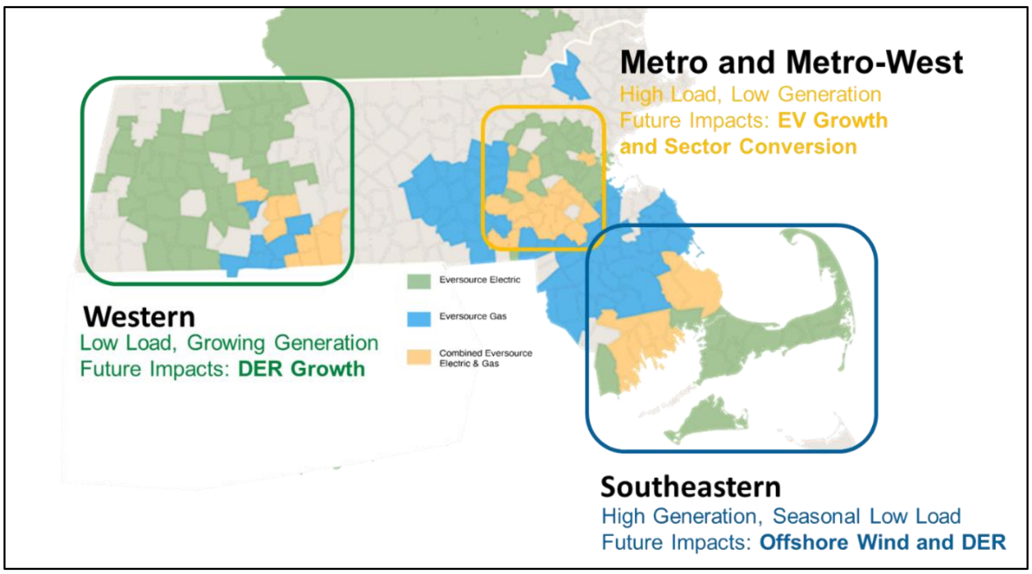


Figure 16: Eversource MA Service Area and Key Challenges

In the SEMA region in Spring, for example, the customer load demand is seasonally low when the production of distributed energy resources is high, leading to significant reverse flow during clear April and May days and a very pronounced duck curve, shifting the time of peak even further towards the late evening hours, as discussed earlier. Figure 17 shows an example of the net load on May 1st, in three successive years (2021, 2022, and 2023) in Southeastern Massachusetts (SEMA) with the typical duck curve characteristic shape driven by high solar output above and beyond the load. The peak (net) load on these days occurs after 8:00 PM as shown on the chart. Overall, the DER growth areas, (South and West), are not geographically aligned with the demand growth area (North), which drives the need for infrastructure development to move power from where it is produced to where it's consumed.

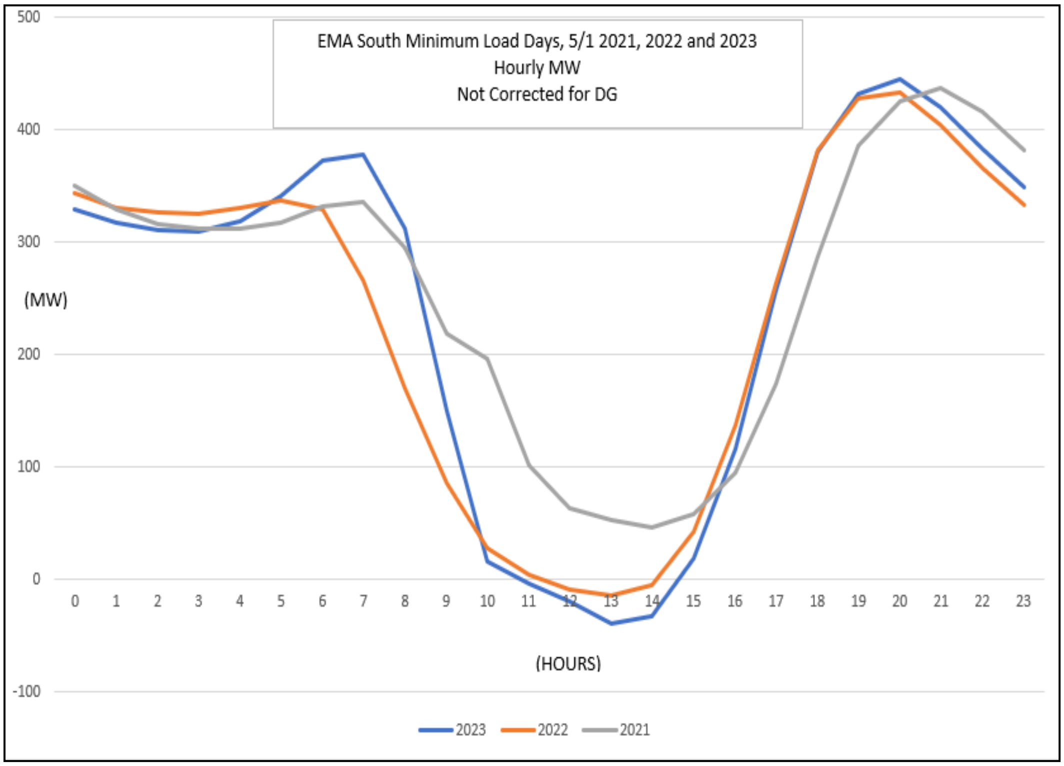


Figure 17: SEMA Load Curve for May 1st, 2021, 2022, and 2023

For much of the last decade, peak load throughout New England has been flat as economic growth was offset by two primary load-reduction drivers: 1) the nation-leading energy efficiency programs run by Eversource (see Figure 18 below) and 2) extensive adoption (more than 477 MW and 66,600 projects) of behind-the-meter[11] (BTM) rooftop solar.[12] Eversource, along with the other Mass Save Program Administrators (PAs),[13] runs nation-leading energy efficiency programs, as authorized by the Green Communities Act (GCA).[14] The GCA mandates that the PAs develop three-year energy efficiency plans that will "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." For over 15 years, Massachusetts has been nationally recognized as a leader in implementing high-quality Energy Efficiency Programs. Since 2009, following the

[11] Defined in this analysis as Simplified projects in the interconnection tariff; numbers are as of June 2023

[12] 2021 Regional System Plan. SO New England Inc., November 2, 2021. Link

[13] The Company notes that the Mass Save programs in the Cape Cod region are delivered by the Cape Light Compact, as a certified municipal aggregator. Therefore, any energy efficiency or demand response numbers in this document for the Company's South Sub-region are partially attributable to delivery by CLC.

[14] Green Communities Act of 2008, as amended and codified at G.L. c. 25, §§ 19, 21, 22

EVERSOURCE

implementation of the Green Communities Act of 2008, Massachusetts has consistently ranked first or second in the nation according to the American Council for an Energy Efficient Economy's State Energy Efficiency Scorecard. These EE investments have resulted in substantial reductions in system-wide energy usage and peak demand. More recently, however, economic growth has outpaced the achievable energy efficiency reductions, and many areas of the system are now seeing growth in peak load. (For more details on the savings associated with energy efficiency, see Section 6.1.5). Along with the success that energy efficiency has had in suppressing the magnitude of the entire load curve, substantial behind the meter solar PV has also been installed throughout Eversource's territory. Due to the output pattern of solar, this has caused a shift of the peak hour from early afternoon to early evening hours.

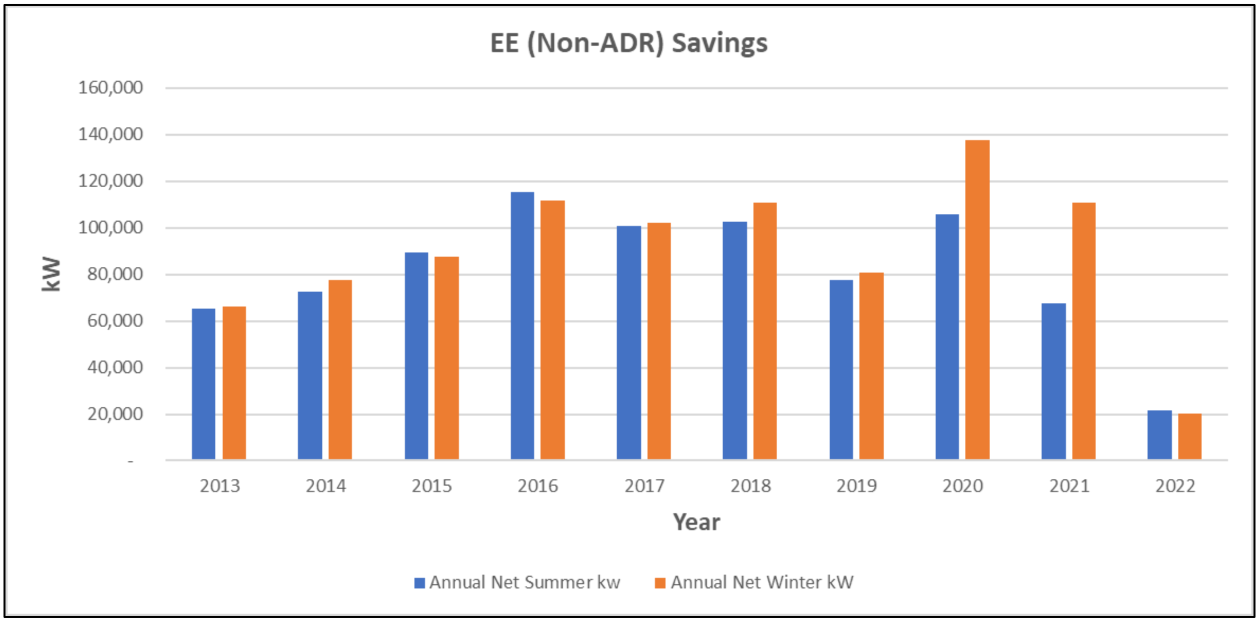


Figure 18: Energy Efficiency (Non-Active Demand Response) Savings 2013-2022

Referencing Figure 19 below, over the last eight years for the entire Massachusetts service territory, while total (coincident)[15] peak load forecast was consistently declining from 2018 to 2021, with relatively flat growth, it has started increased sharply in 2022. As the system peak continues to move towards evening hours, driven by behind-the-meter (BMT) solar installations, the marginal impact of the next MW of BTM solar capacity on said peak shrinks. Figure 19 shows the shifting in overall system peak hour by region (Metro Boston and Metro West are

[15] Coincident peak describes the peak value of the aggregate load of a set of stations. The coincident peak might be at a time and date that does not align with the individual (non-coincident) peak of a substation. For example, the coincident peak of 2 substations might be at 4pm, while the first station peaks at 3:00pm and the second at 6:00pm (non-coincident peak). All plots in this and the following sections are based on the aggregated sum of the individual station peaks.

represented in a single chart). For example, in the bottom graph representing the Western region from 2004 to 2009, the system peak was between 1:00pm and 3:00pm; after 2019 the peak has consistently been later in the evening from 6:00pm to 8:00pm. The clearly visible trend in shifting of the peak load hour toward the evenings in the Southern and Western Region is consistent with the fact that these areas are where most of the solar deployment the Company is occurring.

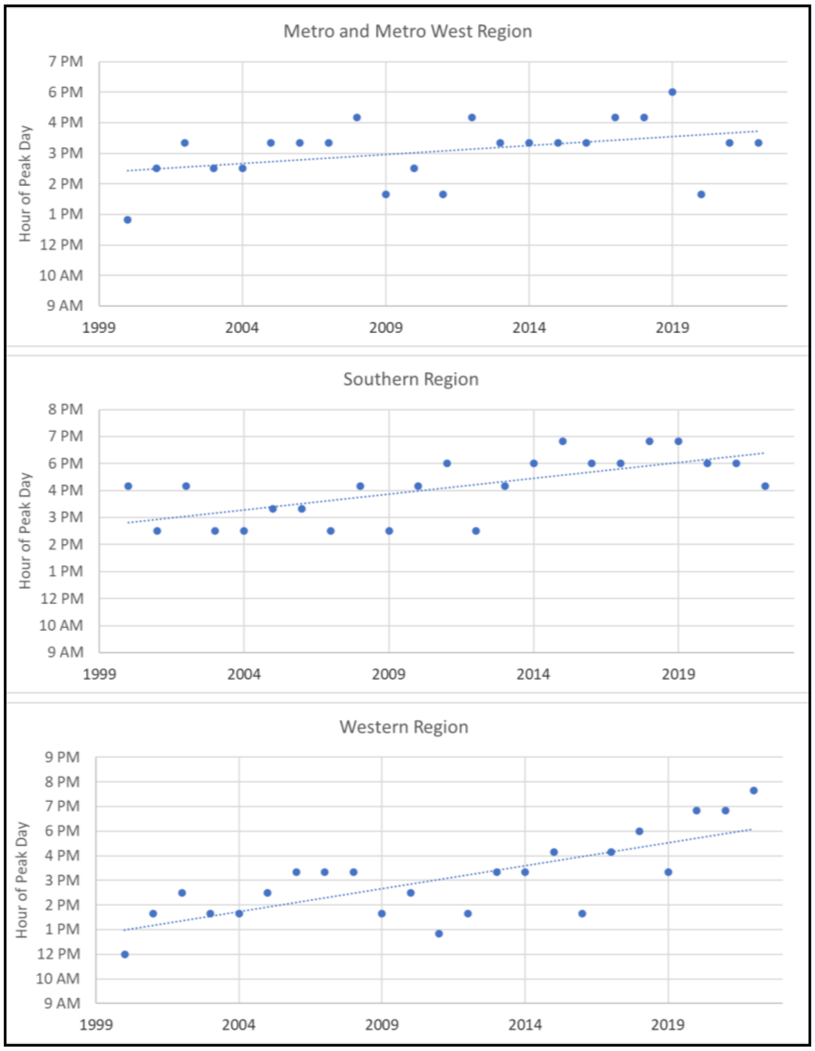


Figure 19: Peak Load Hour in Each Year from 2000 to 2022 By Region

Along with the growth in solar PV, the Commonwealth is now seeing and projecting more aggressive load growth in new areas due primarily to policy directives and clean energy goals. This has prompted evolution of forecasting tools and methods to predict adoption propensities for new technologies (such as EV and heat pumps) so that Eversource can not only assess the magnitude of demand but also the location and associated timing of that demand in the forecast period to enable an orderly planning of the system.

Finally, Eversource is wrestling with the very real and very pronounced impacts of climate change on Eversource's distribution system and customers. Over the past decade alone Eversource has seen four major storms with a return period of 25 years or more. Consequently, Eversource has developed resiliency plans with tactical measures to harden Eversource's system to reduce and mitigate customer impacts. All these challenges exist in some fashion across Eversource's footprint, but in MA, particularly in localized areas, they are more pronounced.

4.1.5. Planning Criteria and Standards

In identifying, designing, and implementing upgrade solutions to resolve violations, Eversource relies on its existing reliability criteria and planning standards to guide the selection of technically viable solutions. The Company's criteria include the following industry standards and Eversource internal standards and planning guides. These guides and standards, taken in the aggregate, comprise the current Eversource policies that pertain to:

1. Providing consistent uniform approach for planning and designing and efficient, reliable, and safe EPS.
2. The study, interconnection, and operation of Distributed Energy Resources (DER) on the Company's EPS

The guides and standards relevant to these two objectives are listed below:

Eversource Distribution System Planning Guide (DSPG): This Eversource guide sets forth standards for distribution system design and system studies including loading criteria, equipment ratings, system voltages, power quality, reliability, standard substation designs, secondary network criteria, evaluation of DER, system modeling criteria, load forecasting, system study methodologies, and modeling assumptions. The Company DSPG, filed yearly as part of the Company's Annual Reliability Report (ARR) - DPU Docket 23-ARR-02, is foundational for developing major capacity projects essential for the Commonwealth's electrification plans including those submitted under the Company's Rate Case Filing under DPU 22-22.

Eversource SYS PLAN 010 Bulk Distribution Substation Assessment Procedure: This Eversource standard pertains to the performance of annual assessments for bulk distribution substations (115 kV transmission down to distribution voltage), including modeling assumptions, software tools, load forecasting, and relevant contingency events to be tested.

The Company's Bulk Distribution Substation Assessment Procedure (SYSPLAN-010) and the Distribution System Planning Guide (DSPG 2020), establish the Company's criteria and guidelines for the planning and design of its bulk substation and distribution facilities, and sets forth the various criteria by which the capacity and reliability performance of the Company's supply systems are measured, and how these assessments are conducted. SYSPLAN-010 states that plans need to be developed to ensure that: Each distribution bus has at least two means of supply (primary and secondary), upon loss of a source of supply, customer electric service is automatically restored, and the number of bulk distribution buses with no power source because of a single contingency is minimized.

In accordance with the planning standards, under normal operating conditions and configurations (N-0), substation transformer loads should not exceed 75% of the normal rating and substation transformers should not exceed their long-term emergency (LTE) rating after implementation of the automatic bus restoral (ABR) scheme in response to N-1 contingency outages involving loss of a bulk transformer. When actual or projected transformer loads approach 75% of the normal rating (under normal operating conditions), the options typically include: (1) permanently transfer loads to other substations in the area, (2) replace/upgrade limiting equipment, such as installing larger transformers, (3) add new equipment or expand substation, (4) construct Non-Wires Alternatives (NWA) such as battery storage, (5) construct new substations. Typically, several solutions are developed for each capacity/reliability need and the process to select a final solution involves many groups and engineering disciplines which consider and compare a range of attributes for each alternative, including cost, reliability, constructability, environmental impact, and others. Large more complex projects such as a transmission line or new substation would typically require regulatory approval for siting and permitting. The final distribution solution must meet the long-term energy need in a reliable manner with minimum impact on the environment at the lowest possible cost.

Eversource Non-Wires Alternative (NWA) Framework: The Company has also developed an NWA Framework to provide a standardized and expedited process to screen an NWA solution's technical and economic feasibility to meet a need at a specific location identified in accordance with the distribution planning criteria. Non-Wires Alternatives are defined as grid investments or programs that use non-traditional solution to achieve deferral of distribution grid capacity equipment or material upgrade, increase distribution grid reliability/resiliency, and increase operational efficiency and optimization of the distribution grid. The primary objective of the Company's NWA framework is to identify solutions with the potential to mitigate system violations (capacity, reliability, and resiliency) or that enable efficiency at a lower total cost.

Eversource Distributed Energy Resource Planning Guide (DERPG): Like DSPG, the DER Planning Guide sets forth the planning criteria, study philosophy and analyses used to study the impacts of Distributed Energy Resources (DER) seeking to safely and reliably interconnect to the Company's Electric Power System (EPS). Distribution Impact studies are performed based on the guidelines as stated in this document.

Eversource Information and Technical Requirements for the Interconnection of Distributed Energy Resources:[16] This is a resource under the Customer Care section of the Eversource

[16] For additional details, refer to: der-information-technical-requirements-2020

website to provide customers and DER developers with the minimum standards and policies of Eversource relevant to the interconnection of DER/DG resources to the Eversource EPS.

IEEE Standard 1547-2018 (and formerly IEEE 1547-2003): Institute of Electrical and Electronics Engineers (IEEE) is the approved standard for criteria and requirements for the interconnection of distributed generation resources into the electric power grid. It is recognized as the governing standard in Massachusetts in the Eversource "Standards for Interconnection of Distributed Generation" tariff MDPU No. 55A.

4.1.6. Planning Process

As a regulated utility, the Company has an obligation to provide reliable service in accordance with applicable safety codes and regulatory requirements. The basic goal is to provide orderly, economic expansion of the equipment and facilities to meet future system demand with acceptable system performance. The key objectives include: build sufficient capacity to meet instantaneous demand; satisfy power quality/voltage requirement within applicable limits; provide adequate availability to meet customer requirements; and deliver power with required frequency.[17]

To meet its obligations, the Company takes a bottoms-up approach to integrated planning, with an annual cyclical planning cycle illustrated in the Chart appearing as Figure 20.[18]

[17] Refer to D.P.U 22-22, Exhibit ES-ENG-1 at 10

[18] In the performance of system planning studies to establish the need for system upgrades, the Company employs detailed steady-state electrical power-flow and electromagnetic transient analyses models of its transmission, substation, and distribution supply systems.

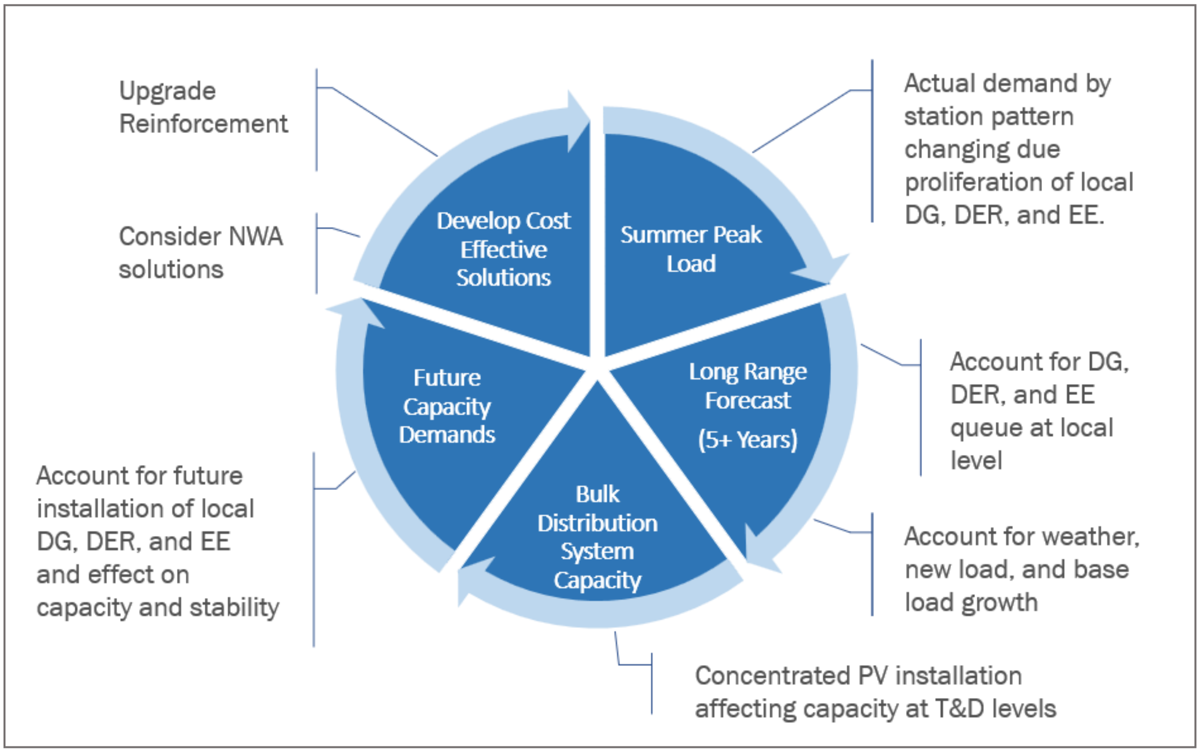


Figure 20: Eversource Annual Planning Cycle

The approach starts with forecasting the net load on the system, i.e., the demand accounting for offsets due to DER production. As part of this process, the Company conducts a yearly analysis to build a 90/10 weather-normalized load assessment based on an econometric model for each of its bulk distribution substations. This assessment is conducted on a yearly basis to support the business-planning process. The Company's assessment evaluates underlying load growth, as well as several adders[19] that will impact the overall peak over and above underlying growth – considering the transition associated with electrification. Lastly, this assessment includes any local generation[20] that has contractual backup capacity through the system, which is available to support the electric grid in case of an asset failure.

The detailed assessment of electric demand is split into two segments: the Near-Term Load assessment, focusing on the next 10 years with projected load growth through new business adoption; and Long-Term Load assessment,[21] which analyzes the Commonwealth's net zero

[19] Adders include large new business growth (step loads), electric vehicle (EV), energy efficiency (EE), and solar PV development.

[20] Such as combined head and power (CHP)

[21] The Company's methodology for the Long-Term Load Assessment is described in detail in D.P.U 22-22, Exhibit ES-ENG-2.

carbon goals to understand the impact on the region. To ensure power system is adequately planned, three scenarios[22] are typically considered when planning for large substation projects:

- **Summer Peak Scenario:** Historically, in most cases, the summer peak scenario is the scenario that drives infrastructure investment. Due to high HVAC consumption during summer months, especially in afternoon and evening hours, the summer peak scenario is directly correlated with the heat index. The summer peak scenario is at its worst when load is highest and local generation (DER) is lowest. Therefore, in the electric demand assessment, this scenario is defined by low, weather adjusted solar output, and a high load.
- **Winter Peak Scenario:** Although the Company's system as a whole is not currently winter-peaking and shows lower temperature-dependent load change during the winter months, the extensive conversion from fossil fuel heating to electric applications is expected to increase the winter load as well as the temperature dependency. This scenario is similarly to the Summer-Peak Scenario looking at high load scenarios with low, weather adjusted DER output.
- **Low Load Scenario:** The low load scenario represents the shoulder months such as April, May, or October where minimal heating and cool applications produce load on the system and solar output can achieve 100% of nameplate power. This scenario uses a low load data as well as ideal solar output conditions. It is designed to identify potential for reverse flow and high voltage conditions on the system.

Based on the 90/10 weather normalized near-term load assessment, detailed analyses are performed to determine when and where violations in planning criteria and performance requirements occur. Specifically, the following analyses are conducted in accordance with the applicable standards and criteria identified in SYSPLAN-010 and the Distribution System Planning Guide DSPG (described above):

I. **Steady-state analysis** to assess thermal overloads and voltage limit violations resulting from load demand and DER output. The steady state analyses are conducted through time series power flow simulations in the steady-state distribution analysis package under both N-0 and N-1 scenarios.
II. **Dynamic/transient analysis** to verify acceptable model performance and to identify any violations of stability criteria or transient overvoltage criteria following system disturbances and switching actions. For this analysis, the steady-state load flow models

[22] For the purpose of the Company's Electric Distribution Substation Demand Assessment, seasons are classified as follows: Summer from June 1st to August 31st; Winter from November 1st to February 28th; and Shoulder Season from March 1st to May 31st and September 1st to October 31st.

are converted to electromagnetic transients (EMT) models to allow for power systems dynamic simulations.

III. **Short-circuit analysis** to assess if circuit breaker fault circuit interrupting capability or bus work short-circuit structural limitations are exceeded, and to inform system protection schemes.

IV. **Protection review** to assess if direct transfer trip (DTT), ground fault (zero sequence) overvoltage (3V0) protection or other special protection schemes are required based on the risk of islanding, back-feed at stations, and other operational requirements.

V. **Reliability and operational flexibility assessment** to determine loss of load/DER reliability risk and degradation in transfer capability following a single-contingency event. This does not constitute a stand-alone analysis, but rather signifies that all previous analyses must account for the various permutations of system configuration, ensuring that the EPS is safe and reliable under all practical operating scenarios.

Following this, the Company identifies the need to plan and construct new equipment, including non-wires alternatives, which expand the capacity of the system, reduces demand, and increases reliability. This, then increases the headroom for new loads and the associated hosting capacity for new electrification as well as additional DERs to connect. Load and enabled DER capacity are then aggregated to the transmission level and constraints on the transmission system are identified, considering generation sources, retirements and commitments. The result is a comprehensive plan that identifies the need for coordinated distribution and transmission solutions in local areas of Eversource's system.

4.1.7. Solution Development - Traditional and Non-Wires Alternatives (NWA):

Once violations and system deficiencies are identified, the Company develops comprehensive plans to position the electric transmission and distribution systems to meet the needs of customers both from capacity, reliability, and resiliency perspective, but also in relation to future electrification. Based on the system analysis results, Eversource engineers design and implement a variety of projects to resolve thermal/capacity, power quality/voltage, reliability and stability violations where station and line equipment may be operating under conditions beyond their design limits. As part of this process, Eversource generally applies several design concepts to resolve and mitigate issues identified in system analysis. Four of the more common design concepts are briefly described below:

I. **Upgrade existing equipment:** By replacing existing equipment with similar equipment with greater capacity, such as increasing the transformer size at a station or reconductoring a distribution feeder, the system capacity is increased.

II. **Construct new equipment/capacity:** Through additional hardware, such as new circuits, substations, or the addition of an extra transformer to a substation the system capacity is increased. An example is the upgrade of substations to standard multibank substation configuration[23] using standard transformer sizes[24] and increasing capacity of the substations that will maximize group firm capacity at the lowest capital cost,[25] up to the point where transmission cost becomes the limiting factor.[26]

III. **Reconfigure the system:** Through load transfers, customers can be moved to different circuits or stations permanently to better utilize resources. This however is limited by the need for sufficient capacity on nearby equipment to support potential N-1 scenarios.

IV. **Construct or apply non-wires alternative solutions**: Where technically feasible and economically viable, through construction of Eversource front-of-the meter NWA solutions or application of behind-the-meter customer solutions, load shapes can be modified to resolve technical constraints, to defer distribution level upgrades.

The high-level solution and benchmark cost estimates may be determined during the system analysis phase. However, final system modifications and costs estimates would require some level of engineering to resolve site-specific issues related to environmental permitting, physical constraints and rights of way, procurement, and construction scheduling, all of which can significantly impact the cost. The Company's reliability-based capacity expansion plans are submitted annually to the Department in the Annual Reliability Report (ARR).[27]

4.1.8. Solution Implementation

Once the comprehensive solution and/or solution alternatives are determined via the system analysis process the Eversource project approval/construction process is used to initiate and implement a capital project. The process is designed to ensure that the technical approach is sound, and resources are budgeted and allocated to facilitate successful and timely execution of the projects. The overall process flow for capital projects is depicted in Figure 21.

As shown in the figure, following the final approval of a project, the initiator secures initial funding for preliminary engineering. The initiator is required to document the project need,

---

[23] Substations with two or more transformers connected to a Common bus provide better reliability than single transformers substations which are limited by distribution line capacity.

[24] Using standard transformer sizes is more cost-effective than step size upgrades (e.g., upgrading from 20MVA to 50MVA to 75MVA in a short time period).

[25] A DER Group Study approach looks at all the substations in the group instead of finding solutions for individual substation or feeder. Accounting for the capacity of nearby substation provides an opportunity for developing cost effective solutions while maintaining the reliability and operational flexibility of the group.

[26] For example, if upgrading a substation from 1 to 3 transformers is cost effective due to minimum transmission cost, then this solution is proposed. If upgrading the same substation from 1 to 4 transformers is cost prohibitive due to significant transmission costs, the proposed substation upgrades will be limited to 3 transformers.

[27] Pursuant to Notice of Inquiry and Rulemaking, D.T.E 98-84/EFSB 98-5 (2003) each electric distribution company must submit to the Department of Public Utilities and annual reliability report (ARR); Refer to 17559379 (comacloud.net) for the 2023 Report.

objectives and include an explanation of the funding request amount, including a budget for conceptual and preliminary engineering activities and a schedule for acquiring full project funding. Key process steps include:

- Project Initiation
- Conceptual Engineering
- Solution Vetting
- Preliminary Engineering
- Full Project Authorization
- Detailed Engineering, Siting, and Permitting
- Construction and Construction Variance Monitoring.

All project documents will be closed, and associated databases updated upon project closeout in accordance with Project Management Process or applicable local project closeout process.

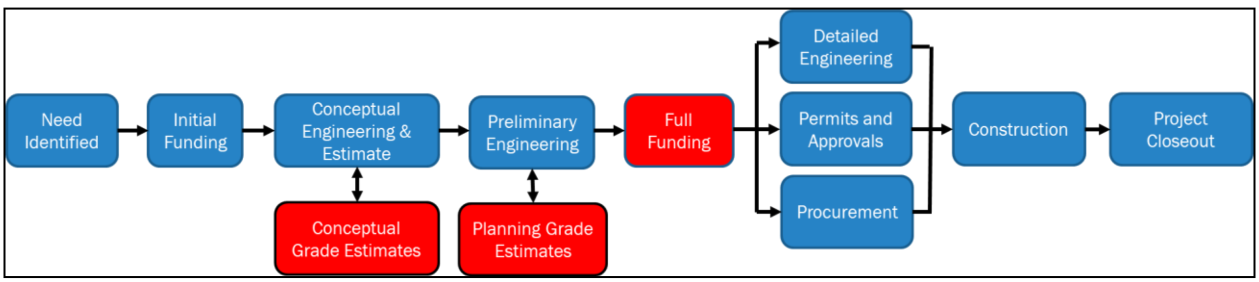


Figure 21: Schematic overview of the approval/construction process

4.1.9. Reliability and Resilience Measures

In Massachusetts and across its tri-state footprint, the Company has historically adopted SAIDI, SAIFI and CAIDI 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.

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 and is mathematically expressed as:[28]

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

The System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time, typically a year, and is mathematically expressed as:

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

A third metric, Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service, and is mathematically expressed as

$$\text{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\sum \text{Total Number of Customers Interrupted}} = \frac{\text{CMI}}{\text{CI}} = \frac{SAIDI}{SAIFI}$$

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 aforementioned 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 (day-to-day customer experience) have the potential to be inherently different from the drivers

---

28 Institute of Electrical and Electronics Engineers. "IEEE Standard 1366-2012." 2012 of major storm performance (also 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. Because 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.

The IEEE Benchmark Survey of key distribution reliability metrics (SAIDI, SAIFI, CAIDI) is conducted annually on an anonymous basis by the Distribution Reliability Working Group (DRWG). The working group attempts to identify various aspects that could cause a difference in reported metrics. However, the data may not be directly comparable due to:[29]

- Data collection and system differences exist
- Certain exclusion differences can occur, although Eversource strives to have the differences minimized
- No exclusions for performance beyond catastrophic event day levels

The 2022 results include data from 74 distribution utilities collectively serving 70 million customers. Table 1 below shows the results of the survey for all utilities, including the quartiles for SAIDI, SAIFI and CAIDI.

Table 1: 2022 IEEE Benchmark Survey Results

74	SAIDI ALL	SAIDI IEEE	SAIDI WOF	SAIDI WOP	SAIFI ALL	SAIFI IEEE	SAIFI WOF	SAIFI WOP	CAIDI ALL	CAIDI IEEE	CAIDI WOF	CAIDI WOP
MIN	28	28	27	27	0.28	0.25	0.24	0.24	48	48	55	55
Q1	161	97	93	86	1.10	0.87	0.77	0.69	130	103	105	102
MEDIAN	236	136	124	118	1.37	1.10	0.96	0.90	172	121	134	130
Q3	443	190	174	161	1.86	1.48	1.26	1.14	255	141	152	152
MAX	7454	456	431	400	4.78	3.73	2.34	2.01	2414	256	256	270

The Company produces an annual Distribution System Resiliency Report, which is filed annually the Massachusetts D.P.U. (docket 23-ARR-02). The report contains "heat maps" of the Company's distribution system, documenting: (1) electric load in MW by substation; (2) Load in

29 Institute of Electrical and Electronics Engineers. "2022 Benchmarking Survey." IEEE Power & Energy Society - Distribution Reliability Working Group, 2022, https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2022-Benchmarking-Survey.pdf.

percentage of circuit rating; (3) customer outage durations in hours; and (4) number of outages affecting customers.

The Company annually reports reliability statistics, as well as other service quality measures, for its distribution system in the Service Quality Index (SQI) filing to the M.D.P.U. (docket 23-SQ-13). Details on reliability and resiliency performance in each region are included in Sections 4.3.9, 4.4.9, 4.5.9 and 4.6.9.

4.1.10. Siting and Permitting – An Overview

Eversource is planning the grid to enable an equitable clean energy transition where the benefits of decarbonization are equitably distributed. This transition is marked by seismic changes in how energy is generated, distributed, and managed. More infrastructure must be built faster to meet state climate and clean energy goals, including Massachusetts' ambitious commitment to achieve net zero greenhouse gas emissions in 2050 and interim targets leading up to that that goal. In sections 6.5.1, the ESMP identifies projects that are critically needed to meet these ambitious goals while increasing capacity, reliability, and resiliency of the electrical grid.

The Commonwealth's current siting and permitting processes are not structured to meet the urgency and scale of this challenge, and without major siting reform, reaching these targets is not possible. The Commonwealth of Massachusetts has recognized the need to remove barriers to responsible clean energy infrastructure development to meet climate and equity goals. Acting on that need, it has created the Commission on Clean Energy Infrastructure Siting and Permitting (CEISP) that will provide a forum to identify administrative, regulatory, and legislative changes to permitting and siting procedures.

Eversource looks forward to the opportunity to provide input, backed by unique position and expertise as system operator, to inform how siting and permitting processes can transition to meet demands of a rapidly evolving energy sector. Eversource will advocate for changes to provide rigorous, consistent, and efficient processes that integrate constructive and equitable engagement within timeframes that enable achievement of Commonwealth targets and goals. Focus should include consideration of the following:

- Expedite state review and permitting processes for electric utility infrastructure projects that contribute to decarbonization, providing streamlined points of contact at the state level and consolidated reviews.
- Establish clear and enforceable deadlines for review and decisions (such issuance of procedural schedules within a specific number of days of filing petition, and Issue decisions within a specific number of days of filing final briefs).
- Increase efficiency and decrease duration of review processes.

- Provide funding, staff and other resources to increase capacity of agencies to process more projects in parallel.
- Identify expedited review pathways for projects that meet certain criteria (e.g., meet a critical capacity need, provide interconnections for off-shore wind, unlock interconnection queues for solar and other distributed energy resources), can demonstrate that impacts will be avoided, minimized and mitigated to the maximum extent possible; and include a community benefit agreement.
- Narrow thresholds to apply to projects to apply to most impactful projects.
- Identify categories of projects that may be exempt from review because impacts are not significant, or impacts can be addressed through adoption of Best Management Practices (BMPs) or standard mitigation commitments.
- Clarify jurisdictional issues and applicability to new technology such as battery storage.
- Provide clear guidance on how to prioritize community engagement at beginning of project development and sustain throughout review process and construction period.
- Evaluate benefit of a Community Engagement Framework discussed in Chapter 3 that can be applied to certain categories of projects to increase engagement and communication with historically marginalized communities.
- Develop best practices for creating and sustaining community engagement through formal and informal review processes.

The following describes the current state of siting and permitting of electrical infrastructure projects in Massachusetts. Siting and permitting in the Commonwealth of Massachusetts is regulated by several federal, state, and local governing bodies. All projects must be consistent with state energy policies as articulated in the Electric Utility Restructuring Act of 1997 (the "Restructuring Act"), the Green Communities Act (c. 169 of the Acts of 2008), the Global Warming Solutions Act (c. 298 of the Acts of 2008), the Energy Diversity Act (c. 188 of the Acts of 2016), the Clean Energy Act (c. 227 of the Acts of 2018), and An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (c. 8 of the Acts of 2021).

State siting and permitting provide opportunities to engage municipalities, residents and other stakeholders in planning and review of the electric system and related projects. Chapter 3.0 of this document addresses stakeholder engagement. Stakeholder engagement is foundational to a just and equitable energy transition and is at the core of how Eversource intends to develop projects associated with its Electric Sector Modernization Plan (ESMP). As the energy sector moves toward a cleaner energy future, the opportunities and challenges of this transition must be considered with a commitment to equity to maximize benefits to customers. This can only be done through deep and committed stakeholder process that is built on an engagement approach in partnership with stakeholders that have not historically participated in the project development and regulatory process, such as those customers living in disadvantaged communities. Eversource will work in partnership with communities and stakeholders to support understanding of the siting project review processes, formal and informal opportunities to participate, project needs, site selection, potential impacts and how impacts can be addressed.

4.1.10.1 Siting

Two agencies govern Siting activities in Massachusetts: the Energy Facilities Siting Board (EFSB) and the Department of Public Utilities (DPU). EFSB and DPU processes are formal, legal proceedings that require the project proponent (e.g., a utility company) to demonstrate that the proposed project is consistent with state laws, regulations, and policies. Most electric projects subject to Siting review are transmission projects; however, some distribution projects, such as new bulk substations, or aspects of distribution projects are subject to review. In many cases, the associated transmission infrastructure will need be coordinated with distribution projects.

Pursuant to G.L. c. 164, § 69J, the EFSB shall approve a petition to construct a facility if, inter alia, the EFSB determines that "plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development polices as adopted by the commonwealth." EFSB has jurisdiction over electric transmission facilities which are defined in the MA General Laws as follows:

- New electric transmission lines which are one mile or more in length, with a design rating of 69 kV or greater in a new transmission corridor.
- New transmission lines which are ten miles or more in length with a design rating of 115 kV or greater in an existing transmission corridor, except reconductoring at the same voltage and/or rebuilding transmission structures.
- Ancillary structures which are an integral part of the operation of any transmission lines. The term "ancillary structure" has been interpreted by the EFSB to include substations or switching station additions.

The EFSB is composed of nine members, six of which represent the following state agencies: the Executive Office of Energy and Environmental Affairs, the DPU (two representatives), the Department of Energy Resources, the Department of Environmental Protection, and the Executive Office of Economic Development (formerly the Executive Office of Housing and Economic Development). Three of the board members are members of the public appointed by the governor with background and experience in Labor, Energy and Environmental disciplines, respectively. Decision is by a majority vote of the Board.

The EFSB requires the submittal of a formal petition, termed a "69J Petition," referencing the section in the MA General Laws establishing its jurisdiction. For electric transmission lines, the scope of EFSB's review includes not only environmental impacts and mitigation, but also the need for and cost of the proposed facility, and alternatives, including other means of meeting the identified need, and alternate routes or sites for such facilities. The statutory deadline for review and issuance of a decision by EFSB is 12 months from the filing of a petition; however, this deadline is not considered mandatory and, in practice, is not adhered to. The time for review and issuance of a decision varies and has increased significantly over the past several years from approximately 18 months to 36 months and beyond.

The DPU (DPU; G.L. c. 164, § 72, approval to construct and operate a transmission line) has jurisdiction over the construction and use of a transmission line or the continued use of a transmission line with a design capacity of sixty-nine (69) kilovolts ("kV") or above, as constructed or with altered construction. For qualifying projects involving the construction and/or use of a transmission line, the DPU requires the submittal of a formal petition, termed a "Section 72 Petition," referencing the section of the MA General Laws establishing such jurisdiction. The DPU review and decisions are not subject to statutory deadlines. The timeline for review and issuance of a decision from the DPU varies and has lengthened over the past several years from approximately 12 months up to 24 months and beyond.

The DPU has the authority to exempt the Company from the operation of certain zoning ordinances if it determines that the proposed use of the land is reasonably necessary for the convenience or public welfare. To request zoning exemptions from the DPU, a "Chapter 40A Petition" must be filed, referencing the section of the MA General Laws establishing such jurisdiction where the municipality will not, or feels it cannot, grant a local exemption.

In addition to the above, projects involving minor modifications to existing transmission facilities require a Request for a Section 72 Determination ("Section 72 Determination") to the DPU. As the applicable statute has no definition of "altered", any modifications that are not a like-for-like replacement, such as a maintenance project that replaces structures with structures that are slightly higher than existing, technically require a Section 72 Determination from the DPU. To improve efficiency, Eversource and the DPU have worked out an abbreviated review process whereby the DPU acknowledges that, in the Company's estimation, the project does not meet the criteria established in Chapter 164, Section 72 of the MA General Laws based on project information submitted to the agency in the Request and is considered non-jurisdictional.

Although EFSB and DPU have two separate and distinct jurisdictions by statute, the Chairman of the DPU has the authority to refer matters to the EFSB. In the case of projects that are sufficient in scope to require submittals to both the DPU and EFSB, the Chairman may refer matters to the EFSB for consolidation.

Projects that will improve reliability, manage load growth, and advance clean energy and climate goals, are increasingly difficult to site. In the past decade, the Company has constructed three major substations that were necessary to maintain a safe and reliable service in the Commonwealth. To meet future demand, this pace must increase exponentially. As will be discussed in subsequent sections of this document, the significant economic growth, increase in electrification and influx of renewable energy are driving demand for siting and construction of many more large substations. The ESMP identifies projects that will be needed through the ten-year planning period (2025-2034). The plan for 2025-2029 includes upgrades to six (6) bulk substations and construction of five (5) large substations. The plan for 2030-2034 includes upgrades to two (2) bulk substations and the construction of nine (9) large substations. In addition, the ESMP includes projects to enable up to 1.5 GWs of DER interconnection which will include upgrades to (14) bulk substations and construction of three (3) bulk substations.

Siting must evolve to meet the urgency and scale of this challenge. It will require meaningful engagement with communities and stakeholders throughout the process – starting with planning and site selection, during EFSB/DPU review, and extending through construction, operation, and maintenance. It will require that Siting agencies have more capacity to process, in parallel, the increased number and complexity of projects. It will require a rigorous, consistent, and efficient process that integrates constructive and equitable engagement within reasonable timeframes that enable achievement of Commonwealth targets and goals.

4.1.10.2 Permitting

Permitting in the Commonwealth of Massachusetts is dependent on the type and total impacts to a specific jurisdictional resource area, such as wetlands or protected habitat. It may also involve coordinating with local, state, and federal agencies. As such, project permitting may range from a straight-forward single permit from one agency to a complex strategy of multiple permits from many agencies. Therefore, permitting timelines can range from 3 months to multiple years due to the number and sequence of permits, required outreach and engagement, and refiling due to agency and stakeholder comments. There is also a lack of certainty with permit durations that often creates permitting challenges and delays. For example, embedded in some of the permitting processes, typically local, are opportunities for welcomed public participation that can introduce significant delays on permitting timelines, especially if there is strong, well-organized opposition.

Some common federal agencies include the Army Corps of Engineers (ACOE), U.S. Fish and Wildlife Service, the Environmental Protection Agency (EPA), and Bureau of Ocean Energy Management.

Common state agencies include the Massachusetts Environmental Policy Act (MEPA) Office, Department of Environmental Protection (MassDEP) and Natural Heritage Endangered Species Program (NHESP), Massachusetts Historical Commission (MHC), Massachusetts Department of Transportation (MassDOT), Massachusetts Bay Transit Authority (MBTA), Massachusetts Department of Conservation and Recreation (DCR), and Massachusetts Water Resources Authority (MWRA). In addition, extensive collaboration and coordination with recognized Tribal communities is necessary through various state and federal permitting requirements.

Common local agencies include the Conservation Commissions, Inlands/Wetlands agencies, Public Works, and City/Town Councils.

4.2. Planning Sub-Regions

As of December 31, 2022, Eversource furnished retail franchise electric service to approximately 1.47 million customers in 140 cities and towns in the eastern and western Massachusetts, including Boston, Cape Cod, Martha's Vineyard, and the greater Springfield metropolitan area, covering and aggregate area of approximately 3,200 square miles.[30]

Based on the trends in load and generation development discussed earlier, the state of the system, including customer and system data, load forecasts and long-term assessments, existing and planned upgrades, as well as specific challenges faced by the Company are presented by Sub-Region in this Section and subsequent Sections.

The Planning sub-regions that comprise the Eversource Massachusetts service area include:

1. EMA-North (former Boston Edison and Cambridge Electric Light Company service area). The EMA-North subregion is further broken down for planning purposes as follows:
   a) Metro Boston sub-region (including the cities of Boston, Cambridge, Somerville, Chelsea, and the Towns of Brookline and Milton), and
   b) Metro West sub-region including 35 communities in the Metro West and North Shore
2. EMA-South (former Commonwealth Electric service area), and
3. WMA (former Western Massachusetts Electric Company service area)

The planning sub-regions are defined this way based on several factors including: historical precedence as Eversource predecessor Company service areas; service area geography; customer demographics; operating voltage and substation and distribution system design characteristics; historical and forecasted load growth characteristics; load density; and DER penetration levels.

The Eversource EMA-North Sub-Region consists of Forty-one (41) Towns and Cities[31] in Eastern Massachusetts. The region consists of the Cities of Boston, Cambridge, Chelsea, Framingham,

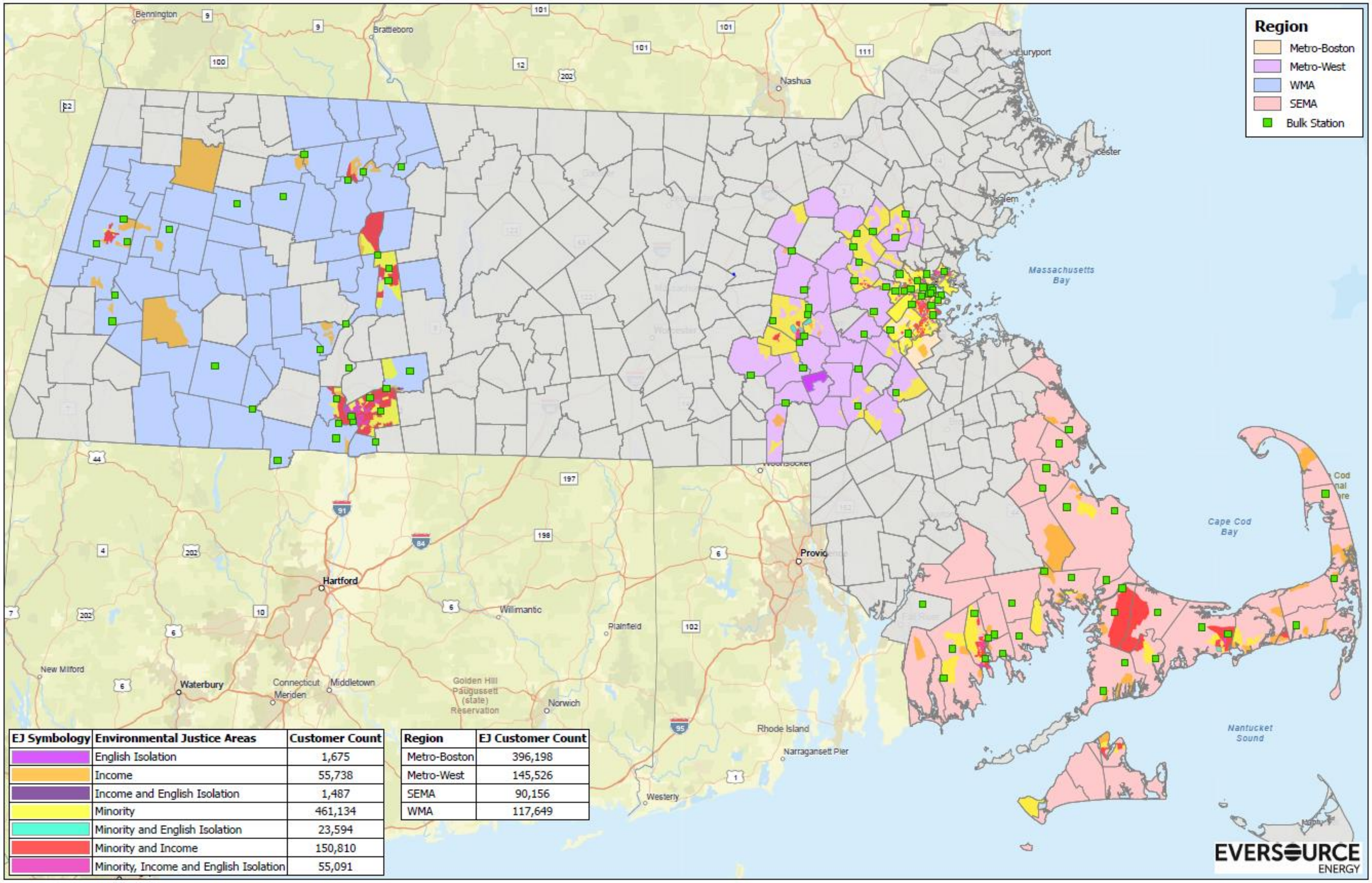
---

[30] Eversource Energy. "2022 Annual Report." Eversource, 2022, 2022-annual-report.pdf (eversource.com)

[31] Including: Acton, Arlington, Ashland, Bedford, Bellingham, Boston, Brookline, Burlington, Cambridge, Canton, Carlisle, Chelsea, Dedham, Dover, Framingham, Holliston, Hopkinton, Lexington, Lincoln, Maynard, Medfield, Medway, Millis, Milton, Natick, Needham, Newton, Norfolk, Sharon, Sherborn, Somerville, Stoneham, Sudbury, Walpole, Waltham, Watertown, Wayland, Weston, Westwood, Winchester, and Woburn.

Newton, Somerville, Waltham, Watertown, and Woburn, and surrounding Towns in Norfolk and Middlesex Counties.

Figure 22 shows the municipalities served by Eversource in Massachusetts shaded by a different color in each planning sub-region. The map also depicts the location of the Company's 101 bulk distribution substations (green squares) and the location, type and number of EJ customers in each region. Each Eversource sub-region is further broken down into separate Area Work Centers (AWC's) which are separate operating Districts.



EJ Symbology	Environmental Justice Areas	Customer Count
	English Isolation	1,675
	Income	55,738
	Income and English Isolation	1,487
	Minority	461,134
	Minority and English Isolation	23,594
	Minority and Income	150,810
	Minority, Income and English Isolation	55,091

Region	EJ Customer Count
Metro-Boston	396,198
Metro-West	145,526
SEMA	90,156
WMA	117,649

Figure 22: Eversource Planning Regions Showing Substation and EJ Community Locations in Massachusetts

4.3. EMA-North Metro Boston Sub-Region

The Eversource EMA-North Metro Sub-Region consists of portions of four Cities, (Boston,[32] Cambridge, Somerville and Chelsea),[33] and two Towns (Brookline and Milton) in Eastern Massachusetts served out of 21 substations with a peak electric demand of approximately 2.0 GW in 2023. This sub-region has a generally lower DER penetration for solar and solar coupled with storage with a total DER from all sources of approximately 265 MW. The service area encompasses a population of approximately 852,000 residents and 383,000 customer accounts.

This sub-region consists of high- to medium-load density areas, including some of the highest density load areas in the country, with load in areas such as downtown Boston and Cambridge served by large underground secondary and spot networks. This sub-region includes many large commercial customers including: Corporate headquarters for major corporations; world-class medical facilities in the Longwood Medical and Downtown areas of Boston; major financial, banking and insurance institutions; city, state and federal government offices; major academic institutions such as Harvard, Massachusetts Institute of Technology (MIT), Boston University, Boston College, Northeastern, Wentworth, Emerson, Berklee, and University of Massachusetts (UMASS) Boston; critical manufacturing, biotech, and scientific research facilities; sports venues such as Fenway Park and TD Garden; major trade show and conference venues such as the Hynes and Boston Convention and Exhibition Center; critical service loads such as the Massachusetts Water Resources Authority (MWRA) and Deer Island water treatment facility; major print media, television and radio broadcasting facilities with a national reach; multiple internet colocation data centers; and electric transit load such as Massachusetts Bay Transportation Authority (MBTA) subway and trolley and the Amtrak Northeast Corridor Northend electrification. Step load growth in the EMA-North Metropolitan subregion is extremely high and is triggering the need for several substation expansion projects and new substation installations, particularly in the Cambridge and Boston areas.

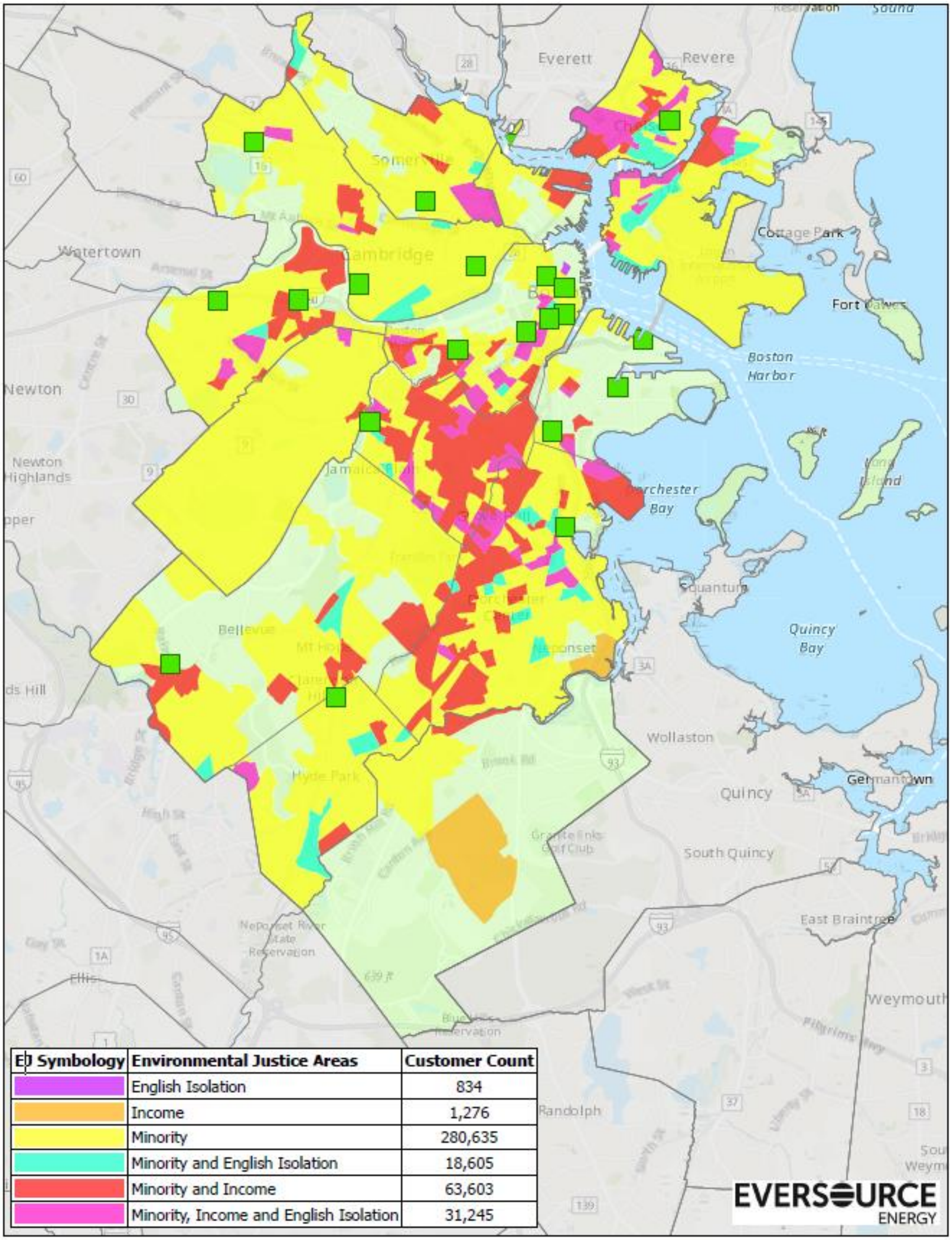
---

[32] The areas and neighborhoods in the City of Boston that are served include: Boston Downtown, Charlestown, East Boston, Allston, Brighton, South Boston, South End, Back Bay, Mission Hill, Beacon Hill, West End, North End, Chinatown, Bay Village, Roxbury, Fenway, South Boston Waterfront, Longwood Medical Area (LMA), Dorchester, Mattapan, Jamaica Plain, Roslindale, West Roxbury, and Hyde Park

[33] The electric utility franchise assignments by Town for Massachusetts are summarized in a Report titled "Electric Utility Franchise Areas in Commonwealth of Massachusetts," prepared by Paul E. Osborne for the Massachusetts D.P.U., last revised November 2021. [Electric Franchises 2021.pdf | Mass.gov]

4.3.1. Maps

Figure 23 shows the boundaries of cities and neighborhoods that comprise the Eversource sub-region of Metro Boston shaded in light green as a base layer. The service area is bounded by National Grid to the North and South, and by Eversource's Metro West region to the West.



EJ Symbology	Environmental Justice Areas	Customer Count
	English Isolation	834
	Income	1,276
	Minority	280,635
	Minority and English Isolation	18,605
	Minority and Income	63,603
	Minority, Income and English Isolation	31,245

Figure 23: EMA-North Metro Boston Sub-Region Showing Substation and EJ Community Locations

The map includes an overlay of the EJ population shaded by type. This is further discussed in Section 4.3.2.2 below.

The location of bulk distributions substation is depicted by green squares. As previously mentioned in Section 4.1.2, the Metro Boston area has very high load density, requiring a high number of large (high capacity) substations in proximity to each other, with many relatively short distribution feeders. Areas of Downtown Boston and Cambridge are served by 120/208 volts secondary networks and some critical customers are served off 277/480 volts spot networks. The extreme load density on these secondary networks and the reliability needs that govern their operation requires numerous bulk distribution substations in relative proximity.

4.3.2. Customer Demographics

Understanding the customer demographics of a region is essential to understanding not only how regions are expected to develop in the future as the system electrifies, but also to understanding how the customer base in the regions has historically been developing.

4.3.2.1 Customer Count

The EMA-North Metro Boston Sub-region consists of 382,600 customer accounts, with an approximate breakout by zip code as shown in Figure 24 below.

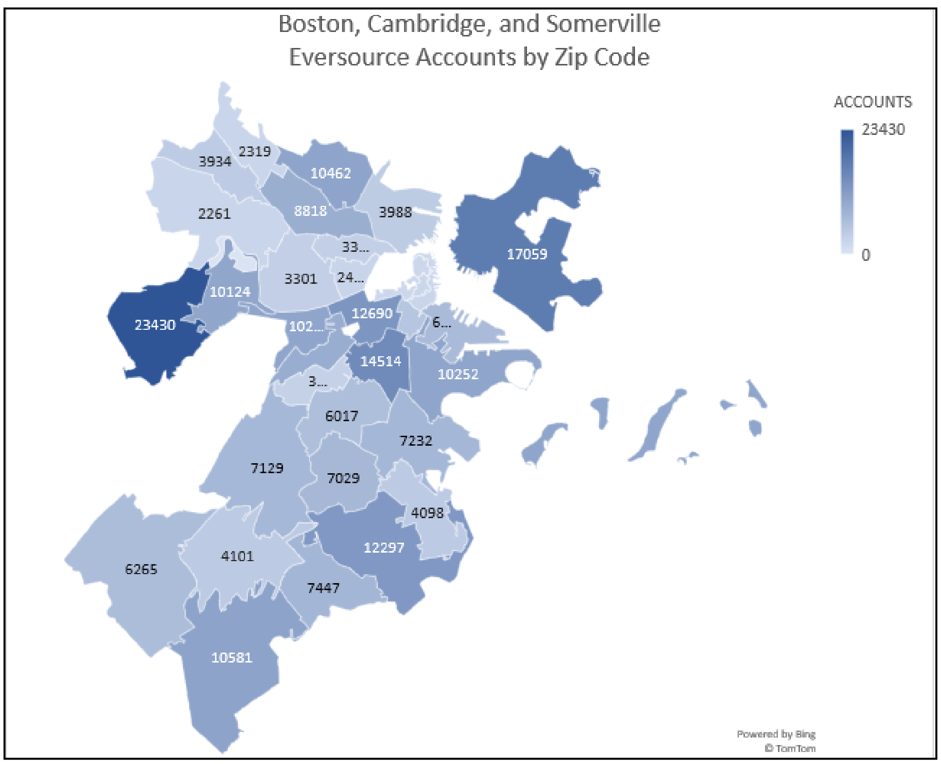


Figure 24: EMA-North Metro Boston Sub-Region Eversource Accounts by Zip Code

The color in the figure has been adjusted to that the zip code with the largest numbers of accounts is darker and the zip code with the least numbers of account is a lighter shade of blue, with the darkest color being the zip code with the most customer accounts. It must be noted that in some cases, some customers will have more than account depending on their electric consumption.

4.3.2.2 Environmental Justice Communities Served

Figure 23 (in Section 4.3.1, Maps) shows an overlay of the EJ population in Metro Boston region derived from the Environmental Justice[34] (EJ) Map Viewer.[35] The EJ Map Viewer an interactive map that displays the 2020 EJ block groups based upon demographic criteria developed by the state's Executive Office of Energy and Environmental Affairs (EEA). As shown, all MA 2020 Environmental Justice Block Groups, especially Minority (yellow), Minority and Income (red), Minority and English Isolation (blue) and Minority, Income and English Isolation (purple) are well represented across this sub-region. The number of customers in each EJ block is shown in the legend. The locations of Eversource bulk distribution substations (green squares) are driven primarily by load density, and, as shown on the map, are geographically dispersed across the sub-region, in both EJ and non-EJ communities.

4.3.2.3 Electrification Customer Classification

To better understand potential regional electrification proliferation, the Company has reviewed its customer data and identified socioeconomic variables relating to a customer’s propensity to adopt heat pumps and electric vehicles. With specific variables driving electrification more than others, variables were ranked in order of importance and then a total score was calculated for each customer by summing their variable rankings. This allowed the Company to assign a priority score to each customer, which was then used to segment the customers into adoption clusters which represented their propensity to adopt both heat pumps and electric vehicles. A detailed accounting of the respective variables and their impact on the adoption propensity modeled by the Company can be found in Section 8.2.2 and Section 8.3.2.

---

[34] In Massachusetts, an environmental justice population is a neighborhood where one or more of the following criteria are true: the annual median household income is 65 percent or less of the statewide annual median household income, minorities make up 40 percent or more of the population, 25 percent or more of households identify as speaking English less than "very well", and minorities make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Environmental Justice Populations in Massachusetts | Mass.gov

[35] Refer to https://www.mass.gov/info-details/massgis-data-2020-environmental-justice-populations for maps and data about Environmental Justice (EJ) neighborhoods in Massachusetts.

For heat pumps, Eversource segmented the customers into 6 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, Cluster V, and Cluster VI. Each cluster represents individual customers' propensity to adopt a heat pump where Cluster I have the highest propensity and Cluster VI has the lowest propensity. For electric vehicles, Eversource segmented the customers into 5 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, and Cluster V. Each cluster represents individual customers' propensity to adopt an electric vehicle where Cluster I has the highest propensity and Cluster V has the lowest propensity.

Figure 25 shows the customer make up by cluster type for heat pumps and electric vehicles for the sub-region. The data show stark differences in customer adoption propensities for both technologies. Only 5% of customers have the highest propensity in Cluster I to adopt heat pumps (with 9% in Clusters I and II), while 8% have the highest propensity in Cluster I to adopt electric vehicles (with 21% in Clusters I and II). Additionally, 21% of customers fall into Cluster VI, the lowest adoption propensity for heat pumps (with 33% in Clusters V and VI) while 29% fall into the lowest adoption propensity, Cluster V, for electric vehicles (with 59% in Clusters IV and V). This shows that in the Metro Boston sub-region the propensity to adopt EV is significantly higher than for heating, driven mostly by the multi-tenant renter units as well as access to natural gas.

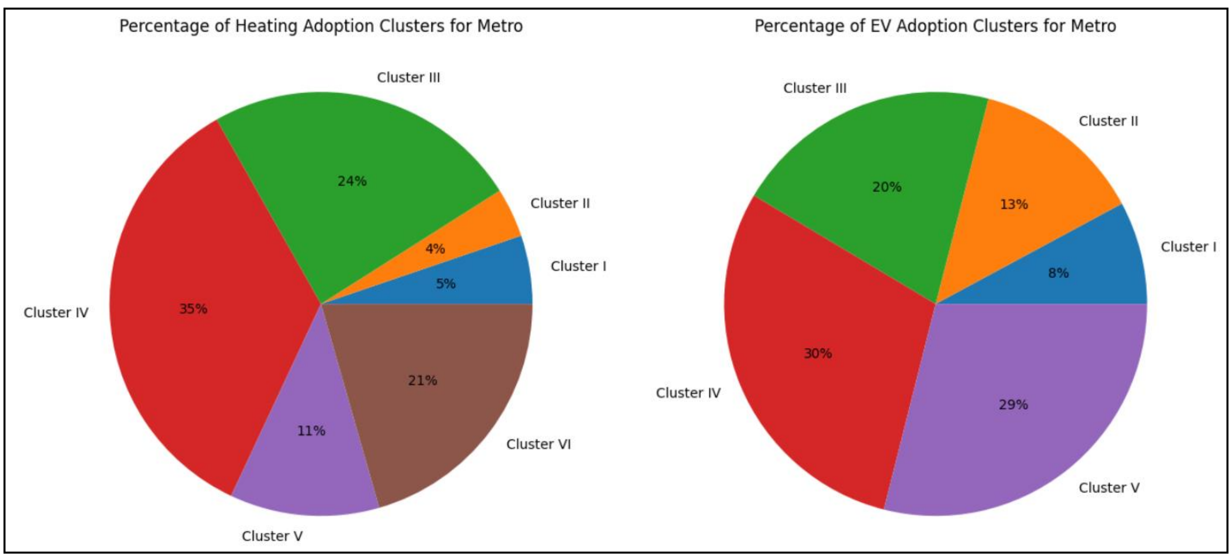


Figure 25: Cluster Percentages for a) heating adoption and b) electric vehicle adoption for EMA-North Metro Boston

4.3.3. Economic Development

The Gross Metropolitan Product (GMP)[36] for Eastern Massachusetts North (encompassing both the Metro Boston and Metro West Sub-Regions due to data granularity) as shown in Table 2 below, has averaged almost two and a half percent growth over the last ten years and has more than recovered after over a three percent decline due to the pandemic in 2020. The data also shows that Real Household Income has maintained just over two and a half percent growth over the last ten years, significantly above the SEMA and WMA Sub-Regions. Income decreased in 2022 as the effects of stimulus packages diminished; however, income has begun to increase again and remains elevated above pre-pandemic levels. After a sizable 9.6% hit due to the pandemic, Total Employment has fully rebounded to pre-pandemic levels and maintains an average 1.1% growth over the last ten years, with an average of 3.5% growth in the last three years. The Unemployment Rate has continued to drop, at an average rate of 5%, over the last ten years, despite more than tripling in 2020. Housing Starts continues to be variable and average a 1% decline over the last ten years, with a difficult response to high interest rates causing large decreases in 2023.

Table 2: EMA-North Historic Economic Development

Eastern MA North Economic Statistics*										
	Gross Metro Product		Real Household Income		Total Employment		Unemployment Rate		Housing Starts	
2014	167		161,132		1,181		5.4		5,770	
2015	174	4.3%	167,435	3.8%	1,210	2.4%	4.5	-20.0%	6,351	9.2%
2016	178	2.3%	171,810	2.5%	1,242	2.6%	3.8	-18.7%	5,957	-6.6%
2017	181	1.6%	178,032	3.5%	1,261	1.5%	3.6	-4.8%	6,570	9.3%
2018	188	3.8%	182,404	2.4%	1,272	0.9%	3.2	-10.4%	6,145	-6.9%
2019	194	2.8%	186,267	2.1%	1,298	2.1%	2.8	-16.3%	4,971	-23.6%
2020	188	-3.4%	198,357	6.1%	1,185	-9.6%	9.7	71.2%	5,296	6.1%
2021	200	6.1%	207,679	4.5%	1,230	3.6%	5.5	-76.2%	7,058	25.0%
2022	205	2.6%	201,581	-3.0%	1,283	4.1%	3.6	-52.2%	7,225	2.3%
2023	211	2.7%	208,637	3.4%	1,319	2.8%	3.2	-13.3%	5,230	-38.2%
CAGR '14-'23		**2.4%**		**2.6%**		**1.1%**		**-5.0%**		**-1.0%**

**Source: Moody's Analytics data for Boston, MA*

4.3.4. Electrification Growth

Electrification of key energy sectors, mobility and heating, has already been taking place over the past decade, albeit at a relatively slow pace. Currently, there is no mandatory reporting of electrification efforts unless customers utilize programs through Mass Save or tap into other funding sources. Therefore, existing electrification numbers are likely undercounting actuals.

---

[36] The market value of all goods and services produced in the region. GMP is the regional equivalent of the Gross Domestic Product (GDP), which measures the nation's economy.

4.3.4.1 Heating Electrification

Massachusetts is near the beginning of the heating electrification transition; while heat pumps in the residential sector have been viable for several decades, overall adoption rates were low until recently. Additionally, technical limitations persist in some portions of the commercial and industrial sectors. As a result, heating electrification has not had a measurable impact on the overall system load to date.

Over the 2019-2023 period, 1,042 homes in the North Metro Sub-Region received incentives from Eversource via the Mass Save programs for the installation of heat pumps to replace fossil fuel heating systems. Of these, 555 were customers replacing oil or propane heat, and 487 were customers replacing gas heat. Eversource notes that under the current Mass Save framework, electrification incentives for customers replacing pipeline gas heating systems are provided by their gas Local Distribution Company (LDC); as a result, Eversource electric does not currently have insight into how many heat pumps were installed at homes that have non-Eversource gas service. Additionally, there may be some heat pump installations that occurred without pursuing a Mass Save incentive, though this number is likely to be small given the generous nature of the incentives.

4.3.4.2 Electric Vehicles

Table 3 shows the current EV count of all Light Duty Vehicles by city in this sub-region. The data highlights the fact that EV deployment in this sub-region is still in the nascent stage, accounting for only 2% of all vehicles in the region. The total of just over 11,000 EV represents almost half the Commonwealth’s 2025 goal for the region.

Table 3: Current EV Count by City for EMA-North Metro Boston

EMA North Metro- Municipality	EV Count (1/1/2023)	EV Count as % of All Vehicles	2025 All Options Goal
Boston, Massachusetts	5,840	2%	
Brookline, Massachusetts	1,410	5%	
Cambridge, Massachusetts	1,770	4%	
Chelsea, Massachusetts	502	1%	4.3%
Milton, Massachusetts	480	2%	
Somerville, Massachusetts	1,022	2%	
Total	11,024	2%	

4.3.5. DER Adoption (Battery Storage and PV Solar)

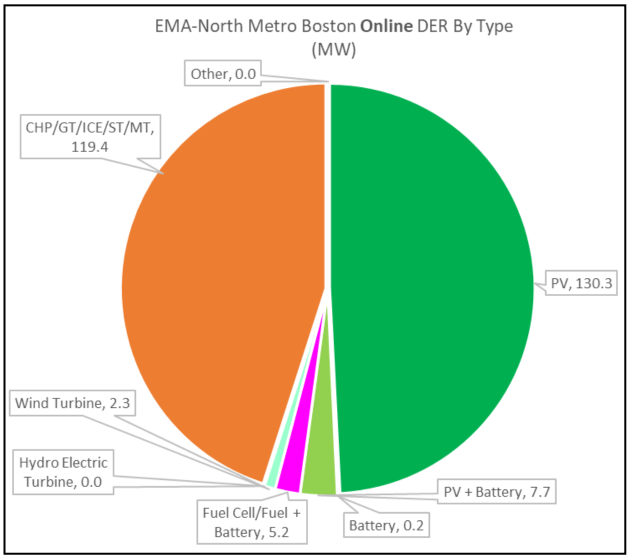
The Eversource EMA-North Metro Boston area has a generally lower DER penetration for solar and solar coupled with battery storage (as a percentage of the sub-region's peak load) and has the smallest share of solar applications in EMA due to the significantly lower proportion of open space in this more highly developed portion of the Company's service territory. The EMA-North Metro Boston area has six network Substations which primarily feed the secondary circuits that supply the downtown Boston area. Because of the unique characteristics of the network circuits, the requirements for secure protection, and existing limitations for control of, and communication with network protectors and associated equipment, the hosting capacity of the network portion of the system is currently very limited for DER Interconnections. The EMA-North Metro Boston area tends to have a higher penetration of CHP (combined heat and power) and gas-fired synchronous generators than the rest of the system due to the higher penetration of larger commercial and industrial customers who are large enough to have their own electric substation equipment. The categories of DER interconnecting in the EMA-North Metro Boston area include behind-the-meter (BTM) battery storage, Combined Heat and Power (CHP) cogeneration, fuel cells, fuel cells coupled with battery storage, gas turbine generators, hydro, internal combustion (diesel) engines, microturbines, standalone and BTM solar, solar coupled with battery storage (both AC and DC coupled), steam turbine, and wind turbines.

As shown in Figure 26 (left side), the total online solar PV currently in the EMA-North Metro Boston region is 130.3 MW with another 7.7 MW of PV coupled with battery storage. The total amount of combined heat and power (CHP), gas turbine (GT), internal combustion engine (ICE), steam turbine (ST) and microturbine (MT) CHP generation is 119.4 MW with 50.7 MW from CHP alone, 57.9 MW of synchronous gas turbines and 10.8 MW of microturbine generation. The total DER from all sources is approximately 265 MW.[37]

The chart on the right side of Figure 26 shows the in-queue DER in the EMA-North Metro Boston region. This includes a significant number of projects with recently completed impact studies that have not been yet interconnected, projects in queue, projects in the application stage, or projects in a prescreen stage without a format application submitted yet. These projects include: 36.3 MW of standalone Solar, 10.3 MW of Standalone BESS and 7.1 MW of Solar coupled with BESS. This accounts for just over 90% of the in-queue MW. In addition, there is about 800 kW of synchronous generation and 4.8 MW of other generation. The total DER in queue or in study process is 59.2 MW, which represents a very low level of DER deployment compared to area native load growth. Based on local irradiance at historical times of peak, this aggregate (both installed and in-queue) Solar and Battery Storage build out translates to 3 MW

[37] Per latest tracking system extraction

of contribution toward North Metro Boston peak demand reduction or 0.1% of 2034 peak demand.



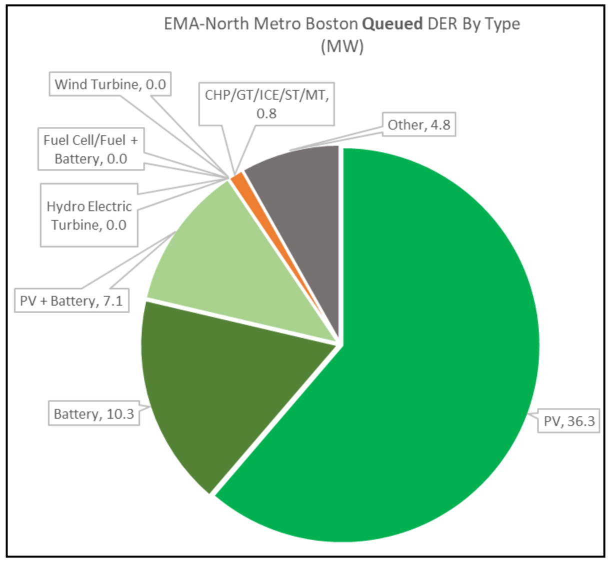


Figure 26: EMA-North Metro Boston Online DER and Queued DER by Technology (MW by Type)[38]

Figure 27 below shows the annual growth in DER interconnections in the EMA-North Metropolitan area since 2010. As seen from the graph, the yearly interconnections in the area have almost doubled over the past five years.

[38] The CHP/GT/ICE/ST/MT category includes combined heat and power (CHP), gas turbine (GT), internal combustion engine (ICE), steam turbine (ST) and microturbine (MT) applications.

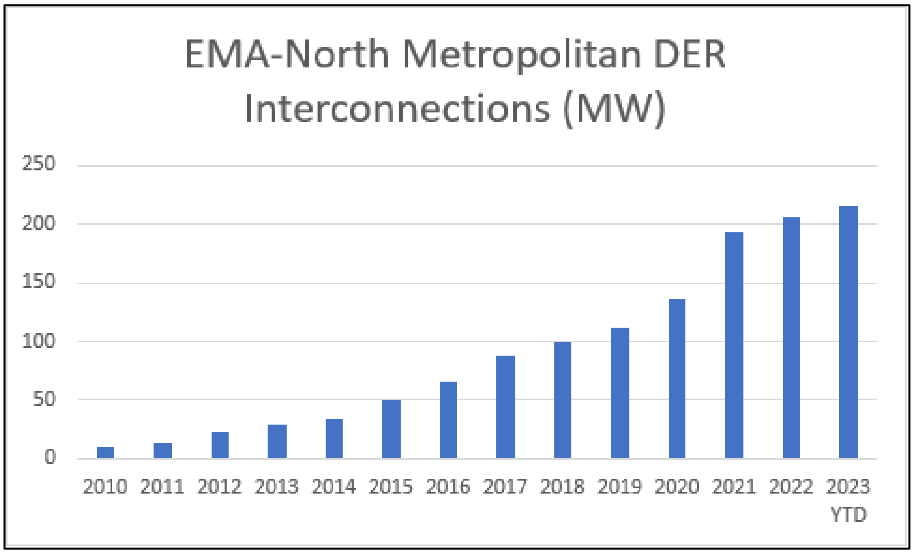


Figure 27: EMA-North Metro Annual DER Interconnections

Like other investor-owned utilities in the Commonwealth, Eversource previously used a first-in, first-out (queued) approach to DER interconnection, with cost causation; meaning, the applications were processed for impact studies in the order received (by substation area) and the applicant paid for system upgrades to address the impacts that their applications caused. Due the large influx of applications, many of them queued for the same substations and towns, this resulted in a significant backlog of applicants. In some cases applicants were waiting in queue for several years.

Under MA DPU dockets 17-164, 19-55, 20-75, and 20-75-B, Eversource and other stakeholders worked with the Department to develop a framework to perform Group studies at saturated substations, to develop more comprehensive solutions, and to propose and obtain approval for alternative cost allocation proposals. As a result, Eversource performed a total of seven Group Studies (six in SEMA) involving multiple substations and multiple project owners, to develop comprehensive solutions for the group study DER and developed an innovate first-in-the nation cost allocation methodology to equitably share the cost for common system modifications between the beneficiaries: developers and distribution customers.

Given Eversource's prior successful completion of the Group Study process and Capital Investment Project (CIP) filings, Eversource has since modified the existing DER Planning process such that today Eversource performs Group Studies to standardize and expedite interconnection studies in the Planning Regions. The Company's foundational assumption is that Cost Allocation methodologies and CIPs such as those proposed under 20-75-B and approved under 22-47 will be applicable to Group Study solutions going forward to avoid some of the known disadvantages of the cause causation principle, including queue stagnation and free rider issues, especially at saturated substations. The Company's cost allocation approach and proposed/planned CIPs are further described in Section 6.

4.3.6. Grid Services

4.3.6.1 Demand Response

In 2022, the Company achieved 1.7 MW of savings from Active Demand Response, delivered through the Mass Save programs, in the North Metropolitan Sub-Region.

4.3.6.2 Smart Inverter Controls

The Company is currently investigating the use of smart inverter controls as a part of customer DER interconnection, but this is not a feature of the current state of the system. However, the Company has successfully demonstrated smart inverter control capability and algorithms on its BESS-based microgrid in Provincetown, MA.

4.3.6.3 Time-varying Rates

The Eversource EMA-North Metro Sub-Region falls within Eversource's Greater Boston and Cambridge service areas. The municipalities in this area are subject to rates[39] that originated under the legacy Boston Edison and Cambridge Electric Light companies. Consequently, general service pricing remains distinct between customers in Greater Boston and Cambridge. Time-varying or time-of-use ("TOU") rates are available in both service areas for medium to large general service customers. These customers fall under the Rate G-2 or Rate G-3 customer classes. Rate G-2 customers are greater than 100 kW and served at a secondary voltage while Rate G-3 customers are greater than 100 kW and served at a primary voltage of 14 kV or 13.8 kV.

TOU rates are on the delivery side only and demand based. This means that demand is assessed to the highest metered demand with a floor on the demand that varies by rate class and service area. TOU definitions are also different by service area. In Greater Boston, the peak period is 9 am to 6 pm weekdays during the months of June through September. From October through May, the peak period is defined as 8 a.m. to 9 p.m. weekdays. In Cambridge, TOU periods are divided into a Peak, Low Load A, and Low Load B. Peak is defined as 9 am to 6 pm weekdays when eastern daylight savings time is in effect and 4 pm to 9 pm weekdays when eastern standard time is in effect. Low Load B is defined as 10 pm to 7 am weekdays and all hours on weekends during both eastern daylight savings and eastern standard time. Low Load A is defined as all hours not included in the Peak or Low Load B periods.

[39] Refer to Electric Tariffs and Rules | Eversource for a complete set of tariffs, riders and adjustments applicable to retail electric service as approved by the Massachusetts D.P.U.

4.3.6.4 Energy Efficiency

In 2022, the Company achieved 14.2 MW of passive peak demand savings in the North Metro region through its delivery of the Mass Save efficiency programs.

4.3.7. Capacity Deficiency

The Company's planning process, including development of solutions for capacity and reliability needs, is discussed in detail in Section 4.1.

In high load density areas, such as the EMA-North Metro Boston Sub-Region, a higher degree of reliability is ensured by maintaining sufficient capacity such that the system can be operated without the loss of power to bulk distribution buses following the loss of the largest bulk distribution transformer at a substation – also known as N-1 Contingency Design.[40]

Through its annual capacity planning processes, as summarized above, and reported in the ARR under D.P.U. 23-ARR-02[41] and as reported in the Company's Rate Case Filing under D.P.U. 22-22,[42] the Company identified municipalities and neighborhoods that are currently supplied by EPS infrastructure with existing capacity[43] and/or reliability[44] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations at capacity now. Table 4 below, list the communities in Metro Boston, not including the city of Boston, in the first column and the existing substation supply deficiency by type (Reliability and/or Capacity) in the fourth column.

---

[40] At the distribution level, it is Eversource's goal to have customer's electric service automatically restored upon loss of supply to bulk distribution supply buses.

[41] Commonwealth of Massachusetts Department of Public Utilities. "2023 Annual Reliability Report NSTAR Electric Company d/b/a Eversource Energy." D.P.U. 23-ARR-02, 2023, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17334261

[42] The list of projects provided is from Responses to IR's RR-AG-26 and DPU 21-4 to the Eversource Rate Case Petition D.P.U 22-22

[43] Capacity deficiency violation is defined as the projected substation peak load exceeding the substation peak or Firm Capacity

[44] Reliability deficiency is defined as a violation of design criteria that results is degraded system performance under emergency conditions. This lower system performance has the potential to result on longer duration and/or more frequent customer outages. This could include long-duration outages of week or even months.

Table 4: Metro Boston Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency/Need	Timeframe for Need
Cambridge[45]	City	Middlesex	Capacity and Reliability	Now/Existing
Chelsea	City	Suffolk	Capacity and Reliability	Now/Existing
Milton	Town	Norfolk	Capacity	Now/Existing
Somerville	City	Middlesex	Capacity and Reliability	Now/Existing

Table 5 below shows the substation name or location in the first column, followed by the Community that is supplied by the substation. The table also shows how loaded the substation is projected to be compared to the substation capacity.[46] Values greater than 100% in the last column of the table is a violation of the company criteria since the transformers expected peak load will exceed the substation capacity. Through its annual capacity planning processes, as noted in the ARR, the company plans to implement a solution for any substation expected to exceed 90% of its capacity during the ten-year planning horizon.

Table 5: Metro Boston Communities and Projected Substation Deficiencies

Substation Name or Location	Communities Supplied	2023 % of Substation Capacity
Hyde Park	Milton, City of Boston	100
Chelsea[47]	East Boston, City of Chelsea	98
East Cambridge	City of Cambridge – East	99
Somerville[48]	City of Cambridge – North	95

[45] Refer to EFSB 22-03 and DPU 22-21, Greater Cambridge Energy Program, Cambridge, Somerville, Boston for all Cambridge Substations forecast and capacity deficiencies.

[46] This number is shown as a percentage and is a division of the substation projected peak load over the substation capacity. As noted in Section 6.2, the Company's criteria and guidelines for the planning and design of its bulk distribution substations is for substation transformers to never exceed the substation capacity.

[47] Refer to EFSB 22-01 Final Decision dated November 30th, 2022, at Table 2

[48] Percent of Substation capacity in 2023 is limited by Distribution System Emergency Limit (66MVA) and assumes upgrades at Somerville Substation #402 have not been placed in-service in 2023. The company had a plan to install a third transformer at the Substations by 2023, now schedule for year 2024. With the 3rd Transformer the forecasted 2023 Percent of Substation capacity is approximately 58%. Refer to EFSB 22-03 and DPU 22-21 at 2-24 and at Table 2-14. Percent of Substation capacity in 2030 assumes the third transformer is in-service.

Similarly, Table 6 below lists the neighborhoods in the City of Boston supplied by bulk distribution substations at capacity now.

Table 6: City of Boston Neighborhoods and Projected EPS Deficiencies

Neighborhood	Deficiency Type	Timeframe for Need
East Boston	Capacity	Now/Existing
Dorchester	Capacity	Now/Existing
Jamaica Plain	Capacity	Now/Existing
Mattapan	Capacity	Now/Existing
Roslindale	Capacity	Now/Existing
Hyde Park	Capacity	Now/Existing

Table 7 below shows the substation name or location in the first column, followed by the neighborhoods in the City of Boston that is supplied by the substation. The table also shows how loaded the substation currently is compared to the substation capacity.[49] This number is shown as a percentage and is a division of the substation projected peak load over the substation capacity. Values greater than 100% in the last columns of the table is a violation of the company criteria since the transformers expected peak load will exceed the substation capacity.

Table 7: City of Boston Projected Substation Deficiencies and Communities Impacted

Substation Name or Location	Community Supplied	2023 % of Substation Capacity
Chelsea	East Boston	98
Hyde Park	Jamaica Plain, Mattapan, Roslindale, Hyde Park	100

As shown in Table 5 and Table 7 above, currently 4 out of 21 substations supplying the Metro Boston area have a capacity and/or reliability violations. Two of the four substations currently at capacity also supply neighborhoods in the City of Boston (Hyde Park and Chelsea) which are covered next. The impact of substation and distribution assets being “at capacity” has multiple

[49] Refer to Footnote 50

facets. Eversource may have to employ measures like temporary load transfers to other substations, may have to install enhanced cooling on substation transformers or other equipment, may have to deploy temporary spot generation in response to a substation or on a distribution feeder for load relief in response to equipment outages, and the Company may be unable to interconnect new large customers short term until the "capacity deficiency" is addressed.

Through its annual capacity planning processes, as noted in the ARR, the company plans to have a solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon. The next few paragraphs describe the need and Company's plan for the substations currently at capacity (Hyde Park, Chelsea, East Cambridge, and Somerville). All these projects have been through the Eversource Capital Approval Process and, in the case of East Eagle and East Cambridge, have EFSB petitions on file. The summary descriptions below are drawn from those proceedings.

- **City of Boston: East Eagle Substation -** Eversource has been permitted under EFSB 22-01[50] for a new 115/13.8kV substation on East Eagle Street in East Boston, with a new incoming 115kV underground transmission line running 3.2 miles from Mystic Substation #250 in Everett, MA, and an incoming 115kV underground transmission line running 1.5 miles from Chelsea Substation #488 in Chelsea, MA. The new substation will consist of two 37/50/62.5 MVA transformers.

The need for this new substation is based on the fact that the Chelsea Substation, which currently supplies electricity to East Boston through a 13.8kV distribution network, is approaching 98% of capacity and has pre- and post-contingency capacity constraints and risk of post-contingency load shedding. The capacity constraint increases to 104% of capacity by 2025.

The East Boston electric load is supplied solely by distribution lines extending into East Boston from the Chelsea Substation. As a result, East Boston is an electrical island with no transmission lines providing service to the residents of East Boston. This situation does not exist for any other subdivision of the City of Boston and it makes East Boston inordinately vulnerable to outages, particularly during peak periods.

The Company has an emergency mitigation plan to be implemented during peak load days. This plan will require strategic load balancing at the distribution feeder and substation transformer level in addition to deployment of spot generation to relieve overloaded transformers in the

---

[50] EFSB 22-01; EFSB 14-04A/DPU 14-153A/DPU14-154A; EFSB 14-04 / DPU 14-153 / DPU 14-154. "Petition for approval to construct and operate two new underground 115 kV transmission lines and new substation in the cities of Boston, Everett and Chelsea, pursuant to G.L. c. 164, §69J and G.L. c.164, §72; and petition for exemption from the Boston Zoning Code, pursuant to Section 6 of Chapter 665 of the Acts of 1956"

event of a transformer failure.[51] This plan will be in effect during peak load day conditions until the new East Eagle substation is in service.

- **City of Cambridge: East Cambridge Substation ("Greater Cambridge Energy Program") -** Eversource currently has a petition before the EFSB under EFSB 22-03 / DPU 22-21[52] for a proposed new 115/13.8kV substation in East Cambridge with adjustments to the area transmission system topology to construct eight new incoming 115kV underground transmission lines to supply it.

The need for this new substation and related transmission and distribution upgrade improvements is based on existing Substations that currently serve Cambridge, including East Cambridge #875, and Somerville #402, both respectively reaching 99% and 95% of capacity at 2023 forecasted load levels. The Cambridge area is experiencing rapid economic development and sustained load growth in the form of significant step load increases.

The complete package of reinforcements under the Greater Cambridge Energy Program will be covered in 6. Eversource has identified and is implementing interim operational measures to address existing substation transformer overloads until the new East Cambridge Substation is placed in service. One interim operational measure was the installation of a 4th transformer and bus section at Putnam Substation #831 with 14kV distribution work from Putnam to the Kendall Square area in 2020. The Putnam Substation #831 initially had three 70 MVA rated transformers with LTE capability of 73 MVA, giving a substation Firm Capacity of 146 MVA. The addition of the fourth transformer with LTE capability of 65 MVA (limited by substation equipment) increased the Putnam Substation #831 Firm Capacity from 146 MVA to 211 MVA, allowing for a total planned load transfer of 34 MVA from East Cambridge Substation #875 to Putnam Substation #831. The Putnam substation is expected to provide 34 MVA of interim load relief to East Cambridge substation via distribution transfers from 2021 to 2024. The second operational measure is the installation of a 3rd transformer and two sections of switchgear at Somerville Substation #402, as discussed below.

The two interim measures provide approximately four years of deferral relief for the greater Cambridge area, before the expected in-service date for the new East Cambridge substation in 2028.

---

[51] Spot generation deployment is typically an interim operational measure of last resort which the Company attempted to avoid in this area and hopes to avoid in other areas through more timely siting and permitting of key substation projects.

[52] EFSB 22-03 / DPU 22-21, "Petition of NSTAR Electric Company d/b/a Eversource Energy Pursuant to G.L. c. 164, § 69J for Approval to Construct and Operate Eight New 115-kV Electric Transmission Lines in Portions of Cambridge, Somerville, and Boston.

If these interim operational measures and associated load transfers were not implemented, for the loss of one transformer, East Cambridge substation would exceed the station's firm capacity, resulting in 92MVA load at risk by 2030. Despite these interim measures, with all adjacent stations near their firm capacity by 2027, along with the East Cambridge substation capacity deficiency, the need for the Project re-emerges by 2028.

- **City of Somerville: Somerville Substation Upgrades -** Eversource has an internally approved project to expand Somerville Substation #402 with a 3rd transformer and related distribution upgrades.

The need for the Somerville Substation expansion is based on the fact that the Somerville Substation, which currently supplies electricity to Cambridge and portions of Somerville, is approaching 95% of capacity.

The expansion of Somerville Substation #402 will permit this substation to address significant step load growth in the MBTA Green Line rail corridor in Somerville, including load increases resulting from the Union Square Revitalization Plan and the Boynton Yards Development.

- **City of Boston: Hyde Park Battery Storage -** Eversource is in the initial approval stages for a proposed 15 MW/20 MWh utility-scale battery energy storage system (BESS) to be connected to Hyde Park Substation #496 in Hyde Park (Boston), MA.

The proposed project is an interim measure to resolve heavy loading conditions at Hyde Park Substation #496, which was projected to reach 100% of capacity based on 2023 forecasted load levels. The Hyde Park BESS will serve as a non-wires alternative (NWA) solution to reduce Hyde Park loading to 95% of rated capacity, until such time as the future Hyde Park-Dorchester Area Supply Plan (refer to Section 6) is completed. A utility-scale BESS solution connected to the distribution lines near the Hyde Park substation can provide 20MWh of demand reduction during peak load days. The optimal design for the BESS is to connect it to distribution lines supplying customers in the Hyde Park and Mattapan neighborhoods of the City of Boston, and for the BESS to be located near the existing Hyde Park Substation. This improves the reliability and operational flexibility by reducing the risk and power losses associated with large underground distribution lines.

4.3.8. Aging Infrastructure

4.3.8.1 Substation Transformers

There are 400 distribution substation transformers in all of EMA (EMA-North Metro West, EMA-North Metro Boston and EMA South). The following chart shows the age of the distribution substation transformers. Of the population of EMA distribution station transformers, 67 or 17%

are older than 60 years, and 236 distribution substation transformers or 59% are less than 45 years old.

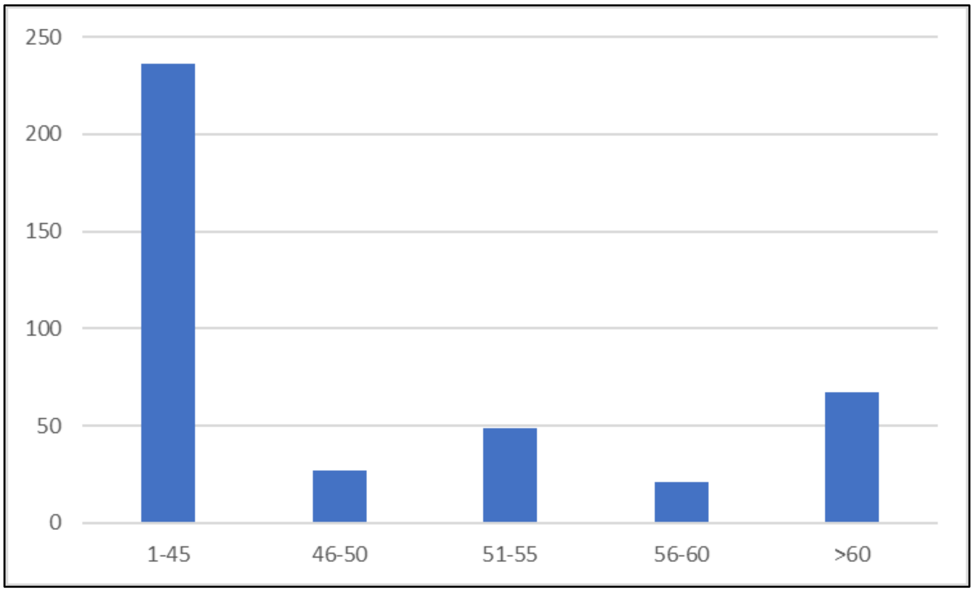


Figure 28: Age of the EMA Distribution Substation Transformer

4.3.8.2 Breakers

There are 2,686 breakers currently in service in all of EMA (EMA-North Metro West, EMA-North Metro Boston and EMA South). The following chart shows the age of 2,090 breakers. 216 breakers or 10% of the EMA breaker population with age records are at or over 50 years of age. 304 breakers or 15% of the EMA breaker population with age records are at or under 10 years of age.

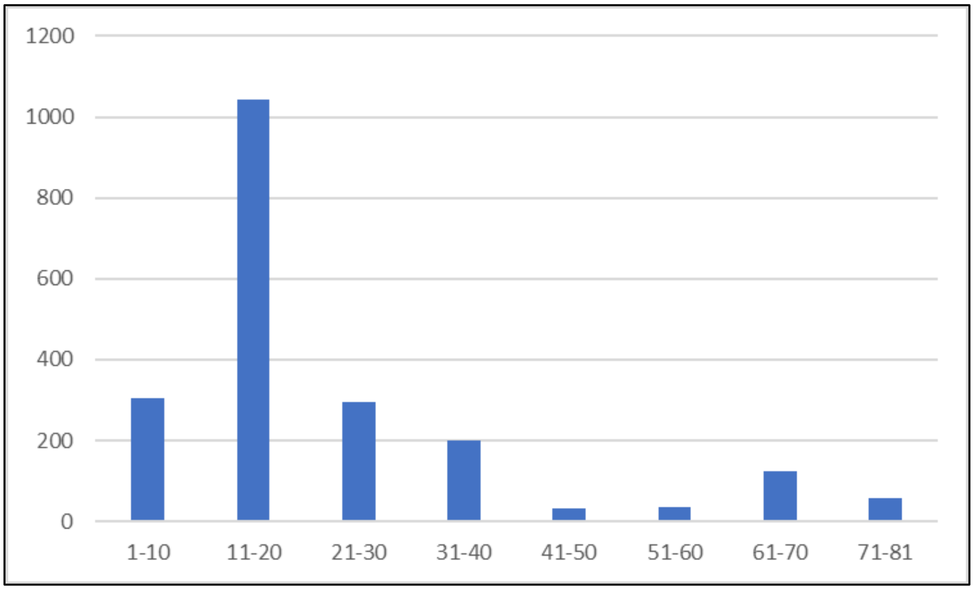


Figure 29: Age of the EMA Substation Breakers

4.3.8.3 Reclosers

There are 86 reclosers currently in service in all of EMA (EMA-North Metro West, EMA-North Metro Boston and EMA South). The following chart shows the age of 28 EMA reclosers. 6 reclosers or 21% of the EMA recloser population with age records are at or under 10 years of age.

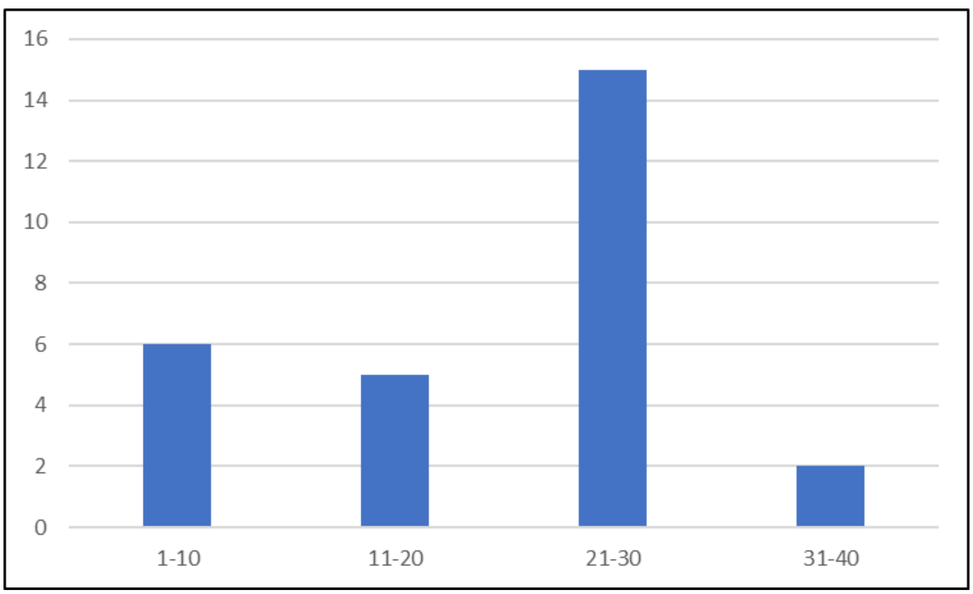


Figure 30: Age of the EMA Reclosers

4.3.8.4 Poles

Out of the 107,831 poles in EMA North Metro Boston, the Company is the custodian of 62,623 poles. The ages of the poles with associated classes are shown in the Table below. There are 32,534 poles (52% of the population) that are Class 1 and 2 poles.

Table 8: EMA-North Metro Boston Pole Age and Associated Class

Age	**1**	**2**	**3**	**4**	**5**	**6**	**8**	**9**	**H1**	**H2**	**H4**	**H5**	**H6**	**NULL**	**NA**	UNK
<=10	167	2968	552	1086	121	23	0	0	0	12	33	11	3	2	273	23
(10,20]	199	7641	612	252	25	0	0	0	2	4	17	1	0	0	82	27
(20,30]	156	9726	617	89	16	0	0	0	5	0	0	10	0	0	200	97
(30,40]	232	4172	4770	277	25	1	0	0	0	0	4	312	0	0	1540	171
(40,50]	261	2041	2484	1635	37	22	0	0	0	0	0	1	0	0	9	981
>50	234	4210	7644	4036	629	26	0	0	0	0	0	6	0	0	239	283
NULL	19	508	523	196	24	0	0	0	0	0	0	0	0	0	0	19

The Company has developed an asset health model for poles. This involves a calculation of the effective age of poles based on the asset characteristics, the asset's utilization, and maintenance. The Company considers this a first step to upgrading its maintenance, inspection, and operation practices and to progressing towards condition-based infrastructure replacements, instead of asset age-based replacements.

The core of the model consists of developing an analytical methodology to calculate pole health based on various inputs typically found in inspection records. Eversource uses existing inspection records to train and test the model. Specifically, Eversource used 190,000 EMA poles owned and maintained by the Company with inspection records and split them randomly in a training set of 95,000 poles (Set A) and an equinumerous testing set of 95,000 poles (Set B).

The first part of the model uses inputs like age, disorientation, internal wood rot, mechanical and fiber damage and circumference to calculate pole health. These inputs are quantified to exhibit the different levels of condition/ranking of the pole for each input. Then, Eversource utilizes a supervised learning model, where the coefficients used to effectively weigh and sum up all of these quantified inputs/ variables for the cumulative asset health score calculation are trained based on the comparison with the actual asset health found in the inspection reports. The learning set, Set A, comprises approximately 95,000 poles in EMA (all three Divisions) that are owned by the Company. The root mean squared error of this process (aka the mismatch of the calculated and inspected pole strength) is 7.11.

The following charts summarize the calculated asset health of the 95,000 EMA poles in the training set, categorized as Very Good, Good, Fair, Poor and Very Poor. 78% of the training set is in Good or Very Good health (74,358 poles). 7% of the poles in the training set are in Poor or Very Poor health (6,424 poles). Out of the 74,358 Good and Very Good health poles, 67% of them have effective age less than actual age. In the same group of Good and Very Good health poles, the average delta of effective to actual age is about 8 years. Out of 1,711 poles in Very Poor health, 100% of them have effective age more than actual age with an average delta of 45 years.

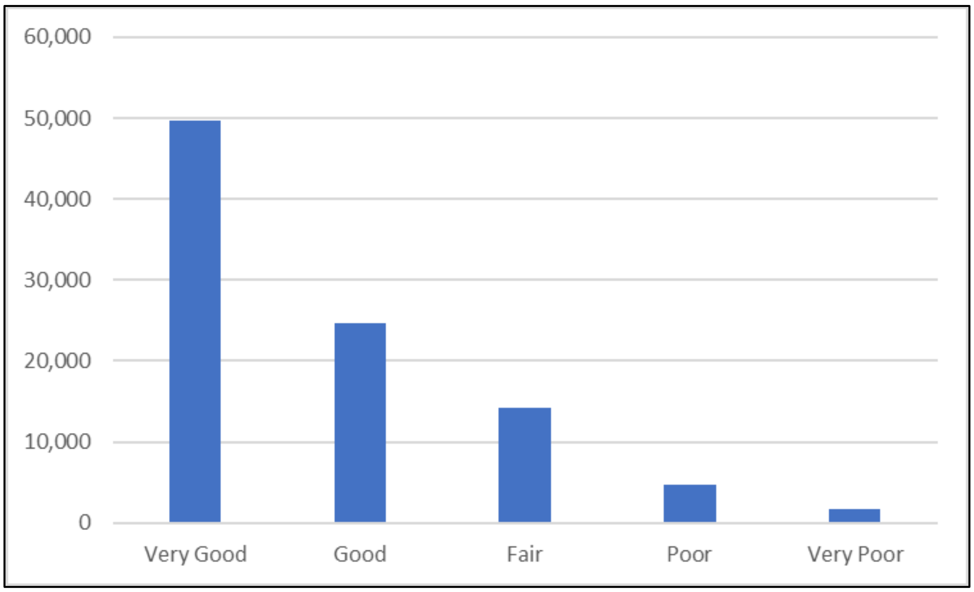


Figure 31: Summary of Calculated Asset Health of EMA Poles in the Training Set

The following table shows the poles' health index relative to the poles' class (within the training set A). There are 32,639 class 1 and class 2 poles, out of which 29,445 or 90% are in Good or Very Good health.

Table 9: Pole Health Index Relative to Pole Class Within Training Set

CLASS	1	2	3	4	5	6	H1	H2	H4	H5	UNK
Very Good	4,183	20,049	10,071	13,535	612	49	49	60	13	10	459
Good	577	4,636	5,723	10,620	1,939	78	4	2	3	11	506
Fair	265	2,104	4,218	6,114	993	55	2	1	1	17	150
Poor	61	600	1,385	1,780	728	66	-	-	-	-	82
Very Poor	17	147	500	741	244	38	-	-	-	-	22
Total	**5,103**	**27,536**	**21,897**	**32,790**	**4,516**	**286**	**55**	**63**	**17**	**38**	**1,219**

The testing part of the model is similar; Eversource calculated the pole health for the poles in the training set, Set B, and then, Eversource compared it to the asset health in the inspection records. The root mean squared error is 7.46.

The following chart shows the asset health of the 95,000 EMA poles in the testing set. 73% of the training set is in Good or Very Good health (69,811poles). 4% of the poles in the training set are in Poor or Very Poor health (3,379 poles). Out of 69,811 poles in Good and Very Good health, 64% of them have effective age less than actual age. In the same group of Good and Very Good health poles, the average delta of effective to actual age is about 7 years. Out of the 1,703 poles in Very Poor health, 100% of them have effective age more than actual age with an average delta of 45 years.

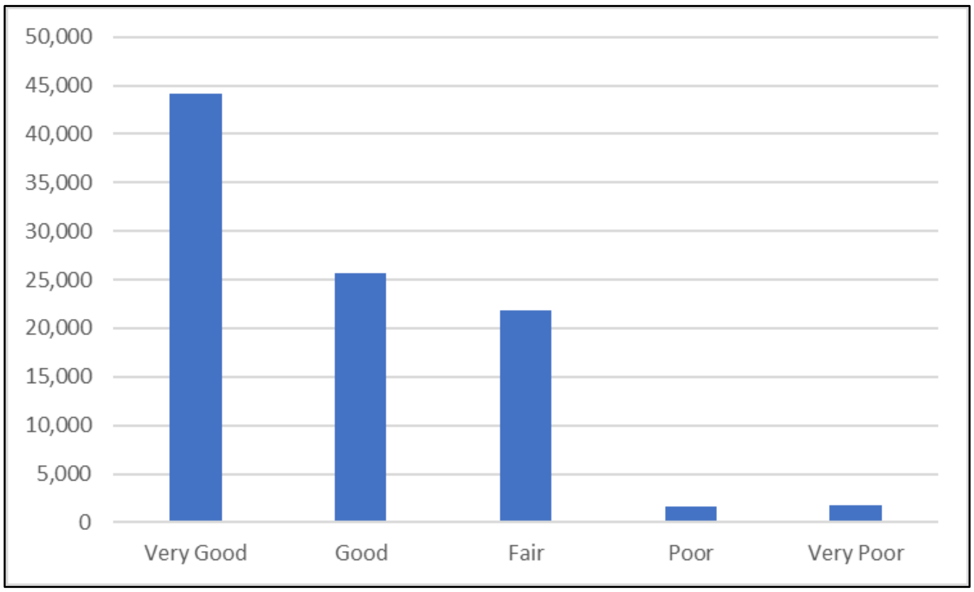


Figure 32: Summary of Asset Health of EMA Poles in the Testing Set

The following graph shows the difference between the effective and actual age of the poles in the testing set. The Mean Absolute Deviation between the effective age and the actual age is 4.78 years. There are 172 total poles where Eversource has observed AHI discrepancy greater than 30 years.

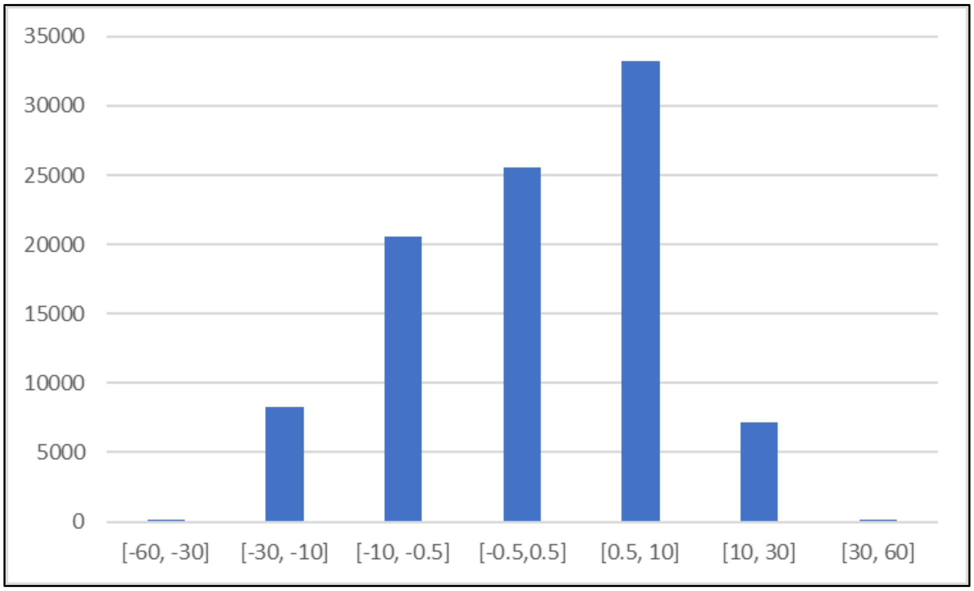


Figure 33: Difference Between Effective and Actual Age of Poles in the Testing Set

The following table shows the poles' health index relative to the poles' class (within the testing set B). There are 32,582 Class 1 and Class 2 poles, out of which 28,648 or 88% are in Good or Very Good health. The results are similar to the results of the testing set, which is desired.

Table 10: Pole Health Index Relative to Pole Class Within Testing Set

CLASS	1	2	3	4	5	6	H1	H2	H4	H5	H6	UNK
Very Good	3,983	18,150	7,210	13,225	637	59	50	53	23	8	2	390
Good	691	5,824	6,989	8,863	1,850	109	1	2	3	13	-	574
Fair	248	3,359	7,091	8,990	1,499	60	4	1	1	13	-	235
Poor	53	77	111	740	582	60	-	-	-	2	-	47
Very Poor	13	184	776	568	105	34	-	-	-	-	-	22
Total	**4,988**	**27,594**	**22,177**	**32,386**	**4,673**	**322**	**55**	**56**	**27**	**36**	**2**	**1,268**

Further, the Company has investigated the sensitivity of the model with the following process. In essence, the sensitivity testing was performed by using the training and testing set in reverse. This is to say that Eversource trained the model parameters using the former testing set, Set B, as the training set. With those calculated parameters, the asset health of the former training set

(Set A), now the testing set, was calculated and the error is the difference of these calculated asset health indices with the inspection data. The root mean square was very close to the starting one, meaning that the model is not sensitive to the training set, which is a desirable quality of training models.

4.3.9. Reliability and Resilience

Section 4.1.9 above includes definitions of commonly used reliability metrics and definitions of blue-sky and all-in performance measures.

4.3.9.1 Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI has been decreasing in EMA North Metro from 2020 to 2022. CAIDI increased slightly from 2020 to 2021 and then decreased in 2022 to below 2020 levels. Compared to the utilities participating in the 2022 IEEE Benchmark Survey (Section 4.1.9, Table 1), the Metro Boston SAIDI, SAIFI and CAIDI are all in the first quartile.

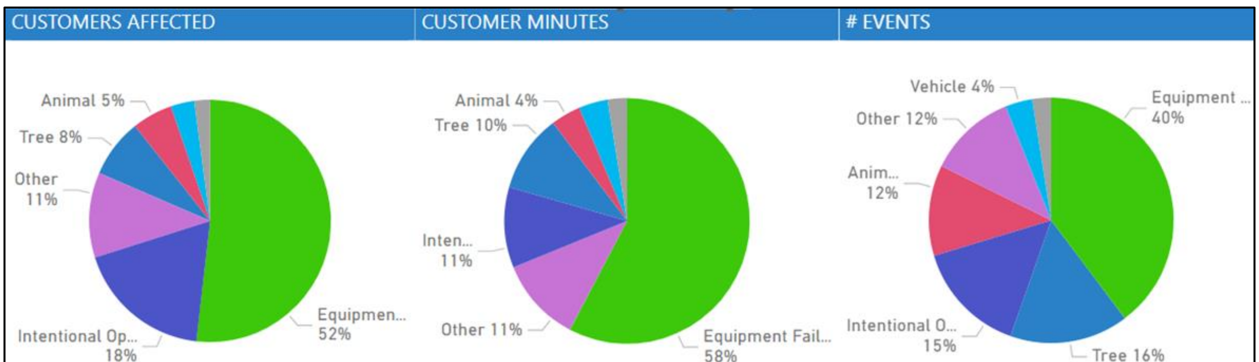
Table 11: EMA-North Metro Boston Blue Sky Reliability Statistics

EMA North Metro	2020	2021	2022
SAIDI	45.1	40.7	38.2
SAIFI	0.40	0.36	0.36
CAIDI	111.4	114.0	104.9

As will be seen from the reliability performance of the other MA Divisions in later sections of this report, the reliability performance of EMA North Metro is better in terms of SAIDI and SAIFI, since the EMA North Metro sub-region distribution system has more underground construction than the other sub-regions. On the other hand, CAIDI is trending high in EMA North Metro compared to sub-regions for all three years (2020-2022), likely also due to the length of time needed to locate and repair faults on underground lines and difficulties working in urban terrain environments.

The following graphs and tables show the reliability performance in EMA North Metro over the past three years (2020-2022). In EMA North Metro, a total of 66,989,083 Customer Minutes of Interruption (CMI) were experienced in 2020-2022. These results show the reliability performance, meaning the duration and frequency of outages during blue-sky days, i.e., excluding major storm days.

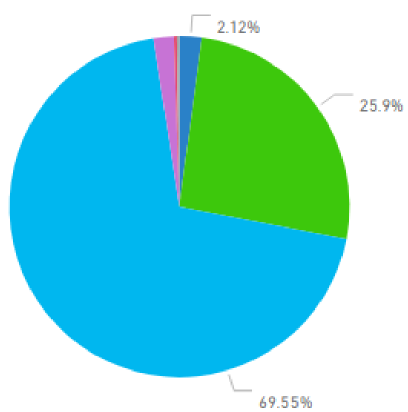
- The leading cause of outages in terms of event counts, customer minutes and customers affected is equipment-related outages as shown in Figure 34. This is consistent with the aging infrastructure issues discussed above. Equipment-related outages are responsible for 58% of the Customer Minutes of Interruption (CMI), 52% of the customers interrupted (CI) and 40% of the events. These percentages (higher CMI and customers impacted percentages than event count percentages) are indicative of equipment-related outages having a wide impact on customers and of causing long durations of outages.
- In addition, a large proportion of the EMA North Metro system is underground and hence less impacted by vegetation. Trees account for 10% of the Customer Minutes of Interruption (CMI), 8% of the customers affected and 16% of the events. In other words, vegetation related outages cause less widespread impacts to customers and are relatively shorter.
- Intentional Operations is another category that had significant contributions to the three metrics used to quantify blue-sky performance, making up 11% of the CMI, 18% of the CI and 15% of the events. Intentional Operations include interruptions for public safety reasons, often requested by towns or municipalities for circumstances such as fire or flood, and so may be indirectly attributable to other categories.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	32,803	2,601,730	95.35	510
Equipment Failure	314,330	38,503,014	189.68	1692
Intentional Operation	110,867	7,068,609	84.11	636
Other	68,848	7,411,250	174.57	495
Tree	47,555	6,843,709	223.60	668
Vehicle	19,216	2,564,495	252.30	152
Weather/ Lightning	12,816	1,705,276	180.30	107
Total	**606,435**	**66,698,083**	**171.28**	**4194**

Figure 34: Leading Causes of Blue-Sky Outages in the EMA-North Metro Sub-Region

Customer Minutes by System Type



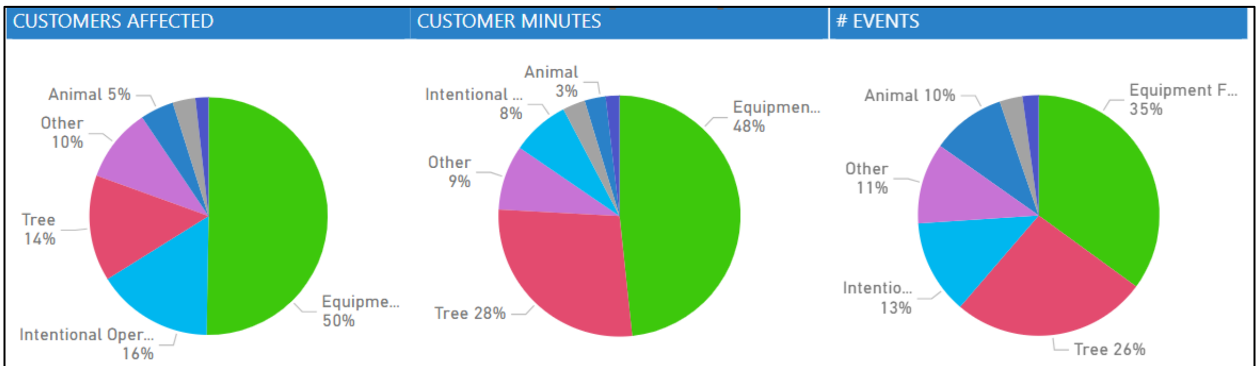
2023 Equipment Failure Types

EQUIPMENT_FAILURE	EVENTS	CUST_AFF	CMI
ASTR-Arrester	13	4,015	608,288
BUSH-Bushing	5	1,536	324,385
CARM-Crossarm	8	2,352	262,878
CBKR-S/S Breaker	30	14,023	1,219,931
CNTR-Connector/Clamp	85	13,623	1,356,177
CONS-Conductor Sec	348	6,075	853,898
COUT-Cutout	188	10,603	1,127,031
DIDB CONP-Conductor Pri	17	868	142,034
DIOH CONP-Conductor Pri	132	36,615	4,063,199
DIUG CONP-Conductor Pri	395	145,514	18,927,613
ELBW-Elbow	12	4,029	517,106
INSL-Insulator	5	827	54,441
MTR-Metering	26	41	7,142
NAPP-Not applicable	1	1	152
NETP-Network Protr	1	6	3,186
OTHR-Other	53	9,218	893,186
PFUZ-Power Fuseholder	1	24	1,704
POLE-Pole/Structure	21	4,238	525,922
RECL-Recloser	4	1,799	88,807
RELY-Relay - S/S	2	72	3,894
SDEQ CONP-Conductor Pri	8	5,343	121,612
SPAC-Spacer	2	2,555	202,057
SPLC-Splice	7	1,738	326,477
SWCH-Switch/Discnt	47	14,022	998,678
TERM-Terminator	1	3	399
TIES-Tie (Insul)	2	107	8,003
UNKW CONP-Conductor Pri	2	737	73,952
UNKW-Unknown	4	2,290	289,099
XFMR-Transformer	285	32,056	5,501,763
Total	**1692**	**314,330**	**38,503,014**

Figure 35: Breakdown of Equipment-Related Outages for EMA North Metro Boston Sub-Region

4.3.9.2 All-In Performance

As discussed earlier, variants of the above metrics can be used to quantify the resilience of the grid. Specifically, Eversource reports the all-in performance that includes major event exclusion days. The all-in CMI from 2020-2022 is 93,408,424. This is an almost 40% increase compared to the aforementioned 66,989,083 blue-sky CMI. This is indicative of severe storms present in the period reported. The charts in Figure 36 below show the breakdown of causes of customers affected, CMI and number of events for the all-in performance. Tree-related interruptions impact is significantly increased in the all-in numbers compared to blue-sky numbers as expected. This is discussed at length later in this report in terms of the worsening impacts of climate change on vegetation and vegetation-related outages.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	32,942	2,637,103	101.75	516
Equipment Failure	364,645	45,135,393	204.01	1815
Intentional Operation	115,024	7,235,644	83.38	656
Other	72,996	8,143,030	213.00	562
Tree	104,598	25,725,010	518.39	1358
Vehicle	22,472	2,812,875	255.58	159
Weather/ Lightning	12,872	1,719,369	188.82	112
Total	**725,549**	**93,408,424**	**258.74**	**5103**

Figure 36: Leading Causes of All-In Outages in the EMA-North Metro Sub-Region

4.3.10. Siting and Permitting

Section 4.1.9 includes an overview of Siting and Permitting in Massachusetts.

As noted throughout the ESMP, the electric system needs additional capacity over the long term to maintain system reliability and serve projected load growth. Electric infrastructure projects have faced significant delays in siting and environmental permitting throughout the Commonwealth, including the EMA region. Projects that will improve reliability, increase capacity of the distribution system, and advance clean energy and climate goals, are increasingly difficult to site and permit.

Two major challenges are: (1) The timeframe for issuing siting decisions has increased significantly, resulting in risks to project development and associated downstream impacts, and (2) Ensuring meaningful community engagement, soliciting constructive feedback, and building support for infrastructure projects is facilitated, which is critical to securing local and state approvals.

Siting delays impact the construction of projects that support the ability to meet the Commonwealth's aggressive clean energy and climate goals. For example, the Greater Cambridge Energy Project is proposed to address a critical load growth issue, has evolved through constructive and meaningful community engagement and is dependent upon a partnership with a real estate developer. The Company filed a petition for the project on March 10, 2022. The procedural conference was not held until July 27, 2023 and the final procedural schedule was issued on August 16, 2023. It indicates that final briefs must be filed by the week of December 4, 2023. It does not include a deadline for issuing a tentative or final decision and there is a risk that it can be extended.

Siting delays also impact the ability to sustain meaningful engagement with communities and stakeholders throughout review processes. Eversource has been working to partner with communities and provide opportunities for meaningful engagement and feedback in project planning and review. Building public support for projects is imperative. Eversource recognizes to be successful, this work must begin upfront, very early in the process so that discussions regarding alternative sites and designs occur before decisions are made. It provides an opportunity to build a common understanding of project need, design criteria/constraints, and costs to inform discussions and minimize misinformation. Constructive engagement, and development of partnerships, from the beginning of a project can translate into less delay and avoid additional costs associated with major design and engineering changes. Extended delays can hamper engagement given participation in planning and review of projects requires significant time commitments that communities and individuals may not be able to sustain over the course of a lengthy review.

As urban areas grow and redevelop, sites and routes that are technically appropriate for electrical infrastructure become less available or are more expensive to develop. To successfully navigate these challenges, partnerships with communities, cities, towns, universities private developers, and many other entities are critical. Partnerships with developers can lead to more efficient use of sites and resources and provide co-benefits, such as creating open space over an underground substation. Unpredictable timeframes put Eversource at risk of losing valuable opportunities to partner with developers. Typical real estate development timelines are often shorter than those required for siting utilities and electrical infrastructure installation must be coordinated with the developers' timeline.

Site conditions, costs, stakeholders, and priorities/policies/regulations can change over the course of a project review. Inflation can increase construction costs. A roadway that had space for an underground line can be encumbered by other utilities and require reengineering, modification of construction techniques and/or mitigation. Saplings within a Right of Way can grow to the point that the must be managed as trees and trigger thresholds that require additional review. Municipal officials and staff, who have helped shape a project can be replaced during elections or change jobs. Abutters and residents may move or disengage from the process and new stakeholders emerge with different concerns or priorities.

Project Status

- **East Cambridge Substation** **("Greater Cambridge Energy Program")** - This project is required to improve system reliability, meet increasing energy demand, and provide capacity for clean energy resources. The project, as currently proposed, evolved through active engagement with the City of Cambridge and a partnership with Boston Properties. The substation, which will be located between Broadway and Binney Street, will be integrated into Boston Properties' redevelopment plans for the Kendall Center Blue Garage. An open and accessible public space will be located above the substation.
  As noted in the previous section, a Petition was filed with the Electric Facilities Siting Board (EFSB) on 3/10/22. A final procedural schedule was issued on August 16, 2023.

- **Hyde Park Battery Project** - This project is proposed as an interim solution to address load conditions at Hyde Park Substation. Eversource is working with the City of Boston to identify what local review and approval may be required and develop a strategy for community outreach and engagement. If the project cannot secure local approval, a 40A filing with DPU may be required.

4.4. EMA-North Metro West Sub-Region

The Eversource EMA-North Metro West Sub-Region consists of parts of thirty-five (35) Towns and Cities[53] in Eastern Massachusetts. Cities in this sub-region consists of Framingham, Newton, Waltham, Watertown, and Woburn, and surrounding Towns in Norfolk and Middlesex Counties. Some Towns served are jointly served with National Grid (Bellingham). The service area encompasses a population of approximately 417,000 customer accounts supplied out of 23 substations with a peak electric demand of approximately 1.9 GW in 2023. This sub-region has medium DER penetration for solar and solar coupled with storage, when compared to WMA and EMA-South, with a total DER from all sources of approximately 337 MW.

This sub-region consists of high to medium load density areas, including heavy commercial and residential areas forming a ring along the Route 128/I-95 beltway around the Boston metropolitan area. This sub-region also includes corporate headquarters for major corporations, area television and radio broadcasting facilities, critical manufacturing, biotech, and research, and critical service loads.

4.4.1. Maps

Figure 37 shows the boundaries of municipalities that comprise the Eversource planning sub-region of Metro West shaded in light green as a base layer. The service territory is bounded by National Grid to the North, West, and South, and by Eversource's Metro Boston region to the East.

The map includes an overlay of the EJ population in Metro West shaded by type. This is discussed further in Section 4.4.2.2 below.

The locations of Eversource bulk distribution substations that supply areas of EMA-North Metro West are depicted as green squares. As previously mentioned in Section 4.1.2, the Metro West area is a suburban area of medium to high load density, requiring distribution substations within close proximity to each other, with a mix of short to average length distribution feeders. No secondary or spot networks are served out of these substations, so the high density of substations as seen in the Metro Boston area is not required.

[53] Including: Acton, Arlington, Ashland, Bedford, Bellingham, Burlington, Canton, Carlisle, Dedham, Dover, Framingham, Holliston, Hopkinton, Lexington, Lincoln, Maynard, Medfield, Medway, Millis, Natick, Needham, Newton, Norfolk, Sharon, Sherborn, Stoneham, Sudbury, Walpole, Waltham, Watertown, Wayland, Weston, Westwood, Winchester, and Woburn.

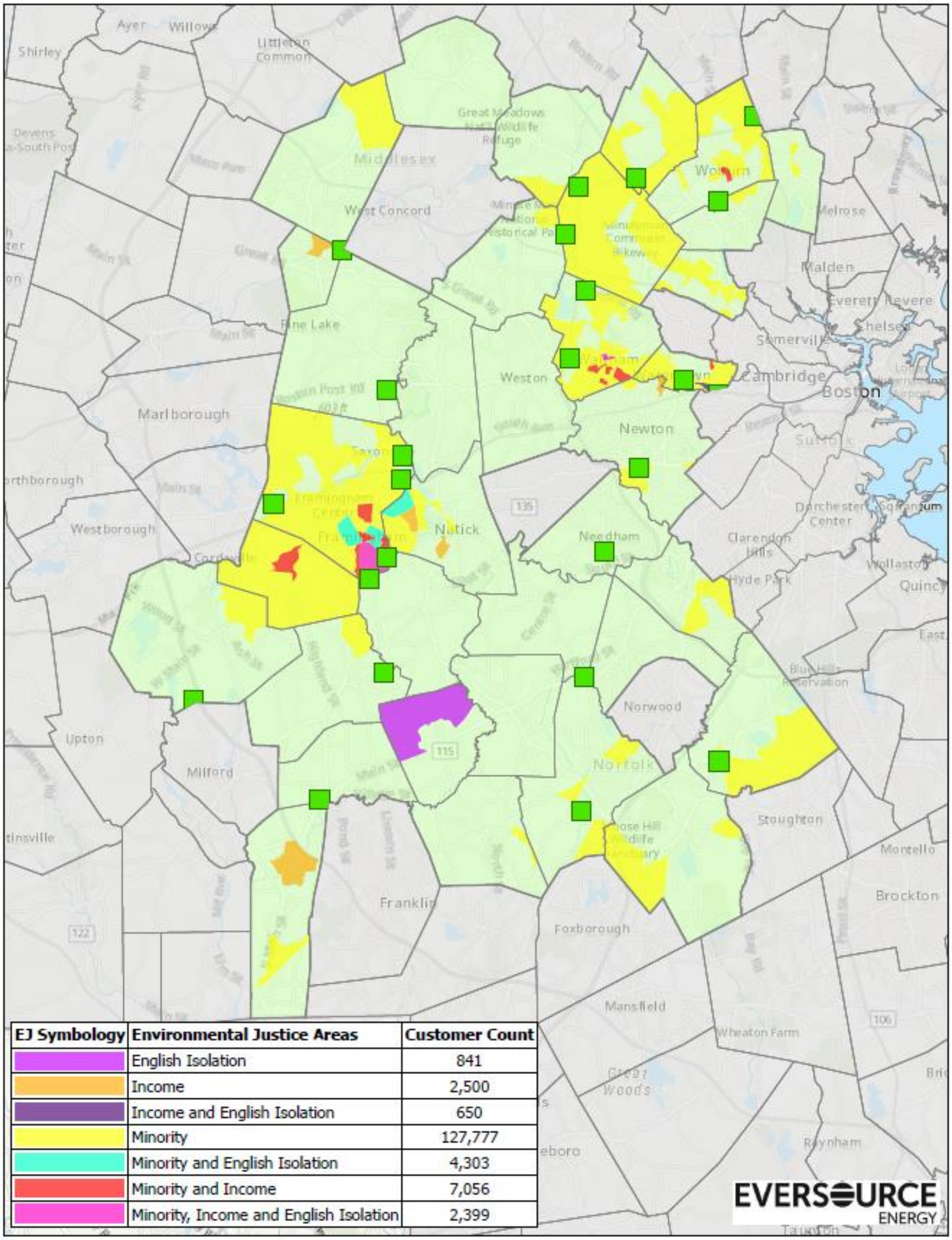


Figure 40: EMA-North Metro West Sub-Region Showing Substation and EJ Community Locations

4.4.2. Customer Demographics

Understanding the customer demographics of a region is essential to understanding not only how regions are expected to develop in the future as the system electrifies, but also to understanding how the customer base in the regions has historically been developing.

4.4.2.1 Customer Count

The EMA-North Non-Metropolitan Sub-region consists of 417,292 customer accounts, with an approximate breakout by zip code as shown in Figure 37 below. The color in the figure has been adjusted to that the zip code with the largest numbers of accounts is darker and the zip code with the least numbers of account is a lighter shade of blue, with the darkest color being the zip code with the most customer accounts. It must be noted that in some cases, some customers will have more than account depending on their electric consumption.

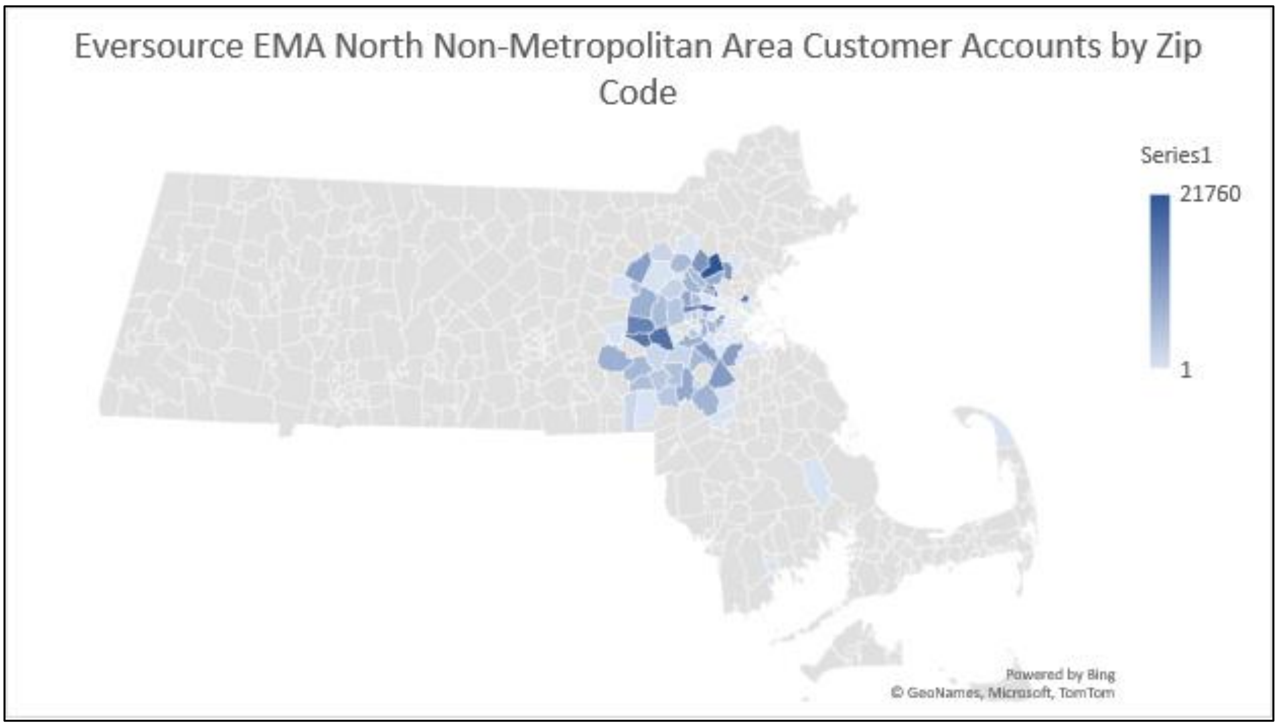


Figure 37: EMA-North Metro West Sub-region Eversource Accounts by Zip Code

4.4.2.2 Environmental Justice Communities

Figure 37 (in Section 4.4.1, Maps) shows an overlay of the EJ population in the Metro West region derived from the Environmental Justice[54] (EJ) Map Viewer.[55] The EJ Map Viewer an

[54] See footnote 35.

interactive map that displays the 2020 EJ block groups based upon demographic criteria developed by the state's Executive Office of Energy and Environmental Affairs (EEA). As shown, most of the MA 2020 Environmental Justice Block Groups, especially Minority (yellow) are represented in this sub-region. The number of customers in each EJ block is shown in the legend. Eversource bulk distribution substations (green squares) are geographically dispersed across the sub-region, in both EJ and non-EJ communities, based primarily on load density.

4.4.2.3 Electrification Customer Classification

In order to better understand how regional adoption of electrification will play out, the Company has reviewed its customer data and identified socioeconomic variables relating to a customer's propensity to adopt heat pumps and electric vehicles. With specific variables driving electrification more than others, variables were ranked in order of importance and then a total score was calculated for each customer by summing their variable rankings. This allowed the Company to assign a priority score to each customer, which was then used to segment the customers into adoption clusters which represented their propensity to adopt both heat pumps and electric vehicles. A detailed accounting of the respective variables and their impact on the adoption propensity modeled by the Company can be found in Section 8.2.2 and Section 8.3.2.

For heat pumps, Eversource segmented the customers into 6 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, Cluster V, and Cluster VI. Each cluster represents individual customers' propensity to adopt a heat pump where Cluster I has the highest propensity and Cluster VI has the lowest propensity. For electric vehicles, Eversource segmented the customers into 5 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, and Cluster V. Each cluster represents individual customers' propensity to adopt an electric vehicle where Cluster I has the highest propensity and Cluster V has the lowest propensity.

Figure 38 shows the customer make up by cluster type for heat pumps and electric vehicles for the sub-region. The data show stark differences in customer adoption propensities for both technologies. 27% of customers have the highest propensity in Cluster I to adopt heat pumps (with 39% in Clusters I and II), while 20% have the highest propensity in Cluster I to adopt electric vehicles (with 44% in Clusters I and II). Additionally, only 8% of customers fall into Cluster VI, the lowest adoption propensity for heat pumps (with 21% in Clusters V and VI) and 16% fall into the lowest adoption propensity, Cluster V, for electric vehicles (with 25% in Clusters IV and V). The Metro West Sub-Region shows a significant propensity for EV and heating adoption.

[55] See footnote 36.

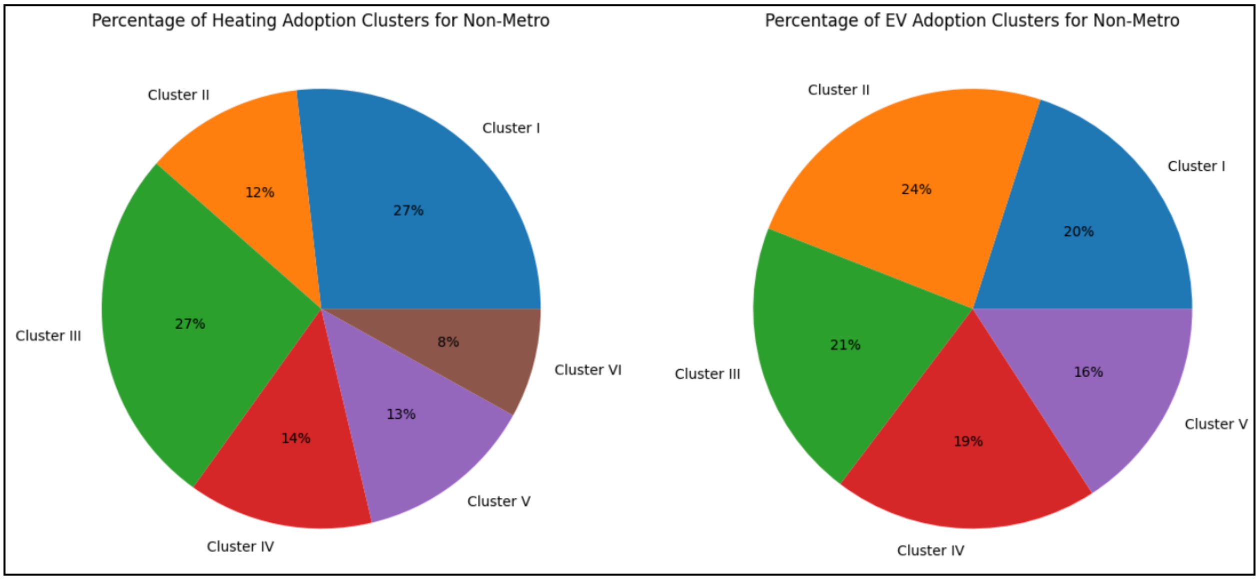


Figure 38: Cluster Percentages for a) Heating Adoption and b) Electric Vehicle Adoption for EMA-North Metro West

4.4.3. Economic Development

The Company's data availability on historic economic development exists for the entire Boston Metro region, and not by EMA-North Metro Boston and EMA-North Metro West Sub-Region. For the entire Boston Metro Region data (encompassing both Metro Boston and Metro West Sub-Region, see Section 4.3.3).

4.4.4. Electrification Growth

Electrification of key energy sectors, mobility and heating, has already been taking place over the past decade, albeit at a relatively slow pace. Currently, there is no mandatory reporting of electrification efforts unless customers utilize programs through Mass Save or tap into other funding sources. Therefore, existing electrification numbers are likely undercounting actuals.

4.4.4.1 Heating Electrification

Over the 2019-2023 period, 5,462 homes in the North Metro West Sub-Region received incentives from Eversource via the Mass Save programs for the installation of heat pumps to replace fossil fuel heating systems. Of these, 4,491 were replacing oil or propane heat, and 971 replacing gas heat. Eversource notes that under the current Mass Save framework, electrification incentives for customer replacing pipeline gas heating systems are provided by their gas LDC; as a result, Eversource electric does not currently have insight into how many heat pumps were installed at homes that have non-Eversource gas service. Additionally, there may be some heat pump installations that occurred without pursuing a Mass Save incentive, though this number is likely to be small given the generous nature of the incentives.

4.4.4.2 Electric Vehicles

Table 12 shows the current EV count of Light Duty Vehicles by city in this sub-region. The data highlights the fact that EV deployment in this sub-region is still in the nascent stage, accounting for only 3% of all vehicles in the region. The total of just over 17,700 EV represents about 70% of the Commonwealth's 2025 goal for the region.

Table 12: Current EV Count by City for EMA-North Metro West

EMA-North Metro West- Municipality	EV Count (1/1/2023)	EV Count as a % of Vehicles	2025 All Options Goal
Acton, Massachusetts	809	4%	4.3%
Arlington, Massachusetts	1,204	4%	
Ashland, Massachusetts	331	2%	
Bedford, Massachusetts	392	3%	
Bellingham, Massachusetts	148	1%	
Canton, Massachusetts	345	2%	
Carlisle, Massachusetts	278	6%	
Dedham, Massachusetts	325	2%	
Dover, Massachusetts	237	4%	
Framingham, Massachusetts	787	1%	
Holliston, Massachusetts	288	2%	
Hopkinton, Massachusetts	529	3%	
Lexington, Massachusetts	1,583	7%	
Lincoln, Massachusetts	365	6%	
Maynard, Massachusetts	176	2%	
Medway, Massachusetts	130	1%	
Natick, Massachusetts	802	3%	
Needham, Massachusetts	944	4%	
Newton, Massachusetts	2,916	5%	
Sharon, Massachusetts	490	4%	
Sherborn, Massachusetts	181	5%	
Stoneham, Massachusetts	231	1%	
Sudbury, Massachusetts	678	4%	
Walpole, Massachusetts	251	1%	
Waltham, Massachusetts	716	2%	
Watertown, Massachusetts	550	2%	
Wayland, Massachusetts	589	5%	
Westwood, Massachusetts	372	3%	
Winchester, Massachusetts	707	4%	
Woburn, Massachusetts	362	1%	
Total	**17,716**	**3%**	

4.4.5. DER adoption (Battery Storage and PV Solar)

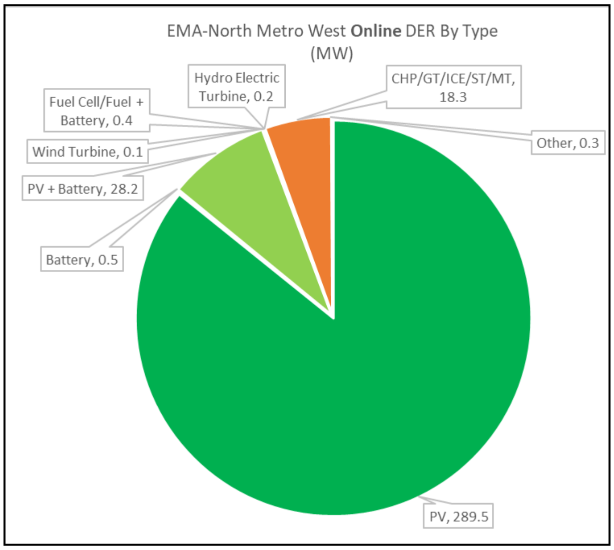
The Eversource EMA-North Metro West area has a generally higher DER penetration for solar and solar coupled with battery storage (as a percentage of the subarea's peak load). The EMA-North Metro West area tends to have a lower penetration of CHP (combined heat and power) and synchronous generators than the rest of the system due to the higher penetration of residential customers. The categories of DER interconnecting in the EMA-North Metro West area include behind the meter (BTM) battery storage, Combined Heat and Power (CHP) cogeneration, fuel cells, fuel cells coupled with battery storage, gas turbine generators, hydro, internal combustion (diesel) engines, microturbines, standalone and BTM solar, solar coupled with battery storage (both AC and DC coupled), steam turbine, and wind turbines.

The largest share of existing online DER interconnections is solar (both standalone and BTM), with and without battery storage. The current online solar total in the EMA-North Metro West area is at least 289.5 MW of solar only and another 28.2 MW of solar coupled with battery storage. Total DER including other technologies is approximately 337.5 MW.[56]

The EMA-North Metro West area has a significant quantity of projects with recently completed impact studies but not yet interconnected, projects participating in Group Studies, projects in queue, projects in the application stage, or projects in a prescreen stage without a formal application submitted yet. These applications include: 31.1 MW of standalone BESS, 57.2 MW of standalone solar and 89.4 MW of Solar coupled with BESS. The total DER in queue or in study process is 197.9 MW. The amount of DER deployment for EMA-North (both metropolitan and non-metropolitan) is less than native load growth. Based on local irradiance at historical times of peak, this aggregate (both installed and in-queue) Solar and Battery Storage build out translates to 60 MW of contribution toward North Metro Boston peak demand reduction or 3% of 2034 peak demand.

Figure 40 shows the growth of DERs in the EMA-North Metro West area since 2010. As seen from the graph, the annual DER interconnections in the area have shown a consistent growth pattern over the years.

[56] Per latest tracking system extraction



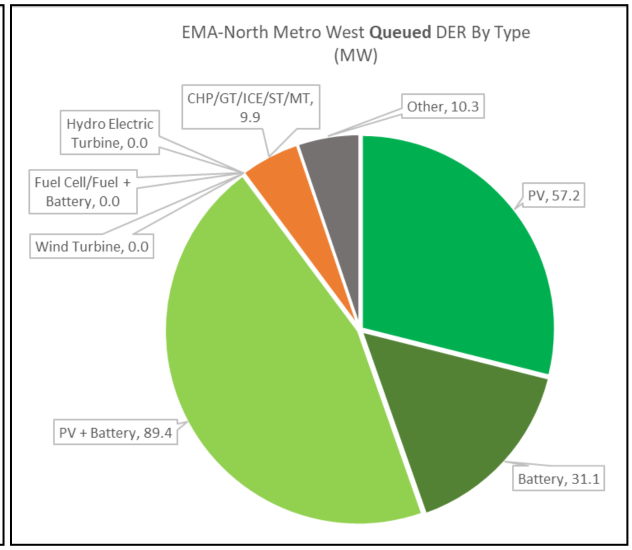


Figure 39: EMA-North Metro West Online DER and Queued DER by Technology (MW by Type)[57]

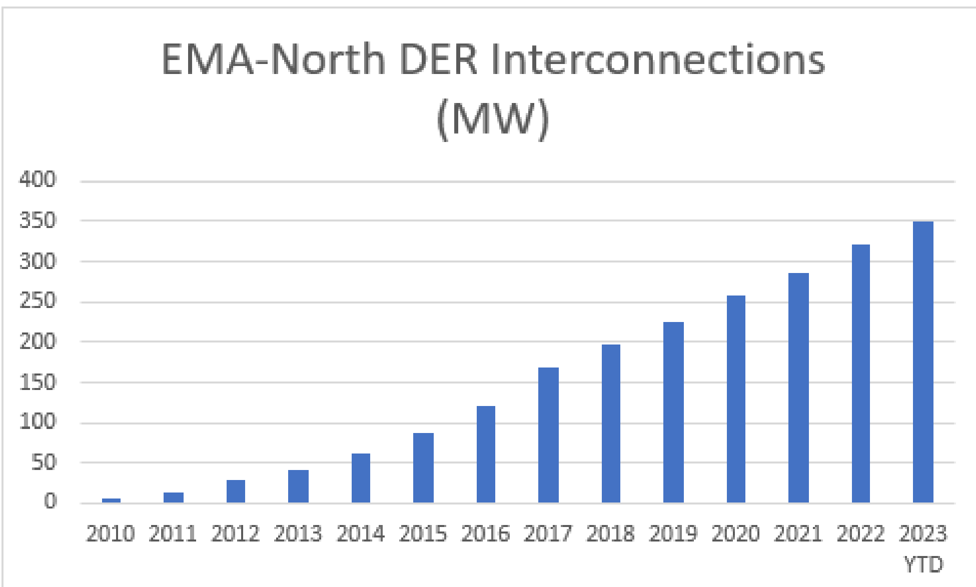


Figure 40: EMA-North Metro West DER Annual Interconnections

Like other investor-owned utilities in the Commonwealth, Eversource previously used a first-in, first-out (queued) approach to DER interconnection, with cost causation; meaning, the applications were processed for impact studies in the order received (by substation area) and

[57] The CHP/GT/ICE/ST/MT category includes combined heat and power (CHP), gas turbine (GT), internal combustion engine (ICE), steam turbine (ST) and microturbine (MT) applications.

the applicant paid for system upgrades to address the impacts that their particular application caused. Due the large influx of applications, many of them queued for the same substations and towns, this resulted in a significant backlog of applicants. In some cases, applicants were waiting in queue for several years.

Under MA DPU dockets 17-164, 19-55, 20-75, and 20-75-B, Eversource and other stakeholders worked with the Department to develop a framework to perform Group studies at saturated substations, in order to develop more comprehensive solutions, and to propose and obtain approval for alternative cost allocation proposals. As a result, Eversource performed a total of seven Group Studies (six in SEMA) involving multiple substations and multiple project owners, to develop comprehensive solutions for the group study DER and developed an innovate first-in-the nation cost allocation methodology to equitably share the cost for common system modifications between the beneficiaries: developers and distribution customers.

Following successful completion of the Group Studies, the Company has standardized on Group Studies as an approach to expedite interconnection studies in all Planning Regions. The Company's foundational assumption is that Cost Allocation methodologies such as those proposed under 20-75-B and approved under 22-47 will be applicable to Group Study solutions going forward to avoid some of the known disadvantages of the cause causation principle, including queue stagnation and free rider issues, especially at saturated substations.

4.4.6. Grid services

4.4.6.1 Demand Response

In 2022, the Company achieved 13.9 MW of savings from Active Demand Response, delivered through the Mass Save program, in the EMA-North Metro West Sub-Region.

4.4.6.2 Smart Inverter Controls

See Section 4.3.6.2.

4.4.6.3 Time-varying Rates

The Eversource EMA-North Metro West Sub-Region falls within Eversource's Greater Boston service area. TOU rates are available to medium and large general service customers. These customers fall under the Rate G-2 or Rate G-3 customer classes. Rate G-2 customers are greater than 100 kW and served at secondary voltage while Rate G-3 customers are greater than 100 kW and served at a primary voltage of 14 kV.

TOU rates are on the delivery side only and demand based. This means that demand is assessed to the highest metered demand with a floor on the demand that varies by rate class and service area. In Greater Boston, the peak period is 9 am to 6 pm weekdays during the months of June through September. From October through May, the peak period is defined as 8 a.m. to 9 p.m. weekdays.

4.4.6.4 Energy Efficiency

In 2022, the Company achieved 10.2 MW of passive peak demand savings in the Metro West region through its delivery of the Mass Save efficiency programs.

4.4.7. Capacity Deficiency

The Company's planning process, including development of solutions for capacity and reliability needs, is discussed in detail in Section 4.1.

In medium to high load density areas, such as the EMA-North Metro West Sub-Region, a higher degree of reliability is ensured by maintaining sufficient capacity such that the system can be operated without the permanent loss of power to customers following the loss of a transformer at a substation – also known as N-1 Contingency Design.[58]

Through its annual capacity planning processes, as summarized in Section 4.1, and reported in the ARR under DPU docket 23-ARR-02[59] and as reported in the Company's Rate Case Filing under DPU 22-22,[60] the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing capacity[61] and/or reliability[62] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations projected at capacity now. Table 13 below, list the communities in Metro West in the first column and the existing substation supply deficiency by type (Reliability and/or Capacity) in the fourth column.

Table 13: Metro West Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Burlington	Town	Middlesex	Capacity and Reliability	Now/Existing
Holliston	Town	Middlesex	Capacity and Reliability	Now/Existing
Lexington	Town	Middlesex	Capacity and Reliability	Now/Existing
Medway	Town	Norfolk	Capacity	Now/Existing

[58] See Footnote 41 in Section 4.3.7
[59] See Footnote 42 in Section 4.3.7
[60] See Footnote 43 in Section 4.3.7
[61] See Footnote 44 in Section 4.3.7
[62] See Footnote 45 in Section 4.3.7

Millis	Town	Norfolk	Capacity and Reliability	Now/Existing
Norfolk	Town	Norfolk	Capacity	Now/Existing

Table 14 below shows the substation name or location in the first column, followed by the Community that is supplied by the substation. The table also shows how loaded the substation is projected to be compared to the substation capacity.[63] Values greater than 100% in the last columns of the table is a violation of the company criteria since the transformers expected peak load will exceed the substation capacity.

Table 14: Metro West Projected Substation Deficiencies and Communities Impacted

Substation Name or Location	Community Supplied	2023 % of Substation Capacity
Burlington	Burlington, Lexington, Woburn	94
West Medway	Holliston, Medway, Millis, and Norfolk	93

Currently 2 out of 23 substations supplying Metro West sub-region have capacity and/or reliability violations. Through its annual capacity planning processes, as noted in the ARR, the company goal is to have a solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon. The following paragraphs describe the need and Company's plan for the substations currently at capacity (Burlington and Medway).

- **Towns of Burlington, Lexington, and Woburn: Burlington Substation Upgrades -** Eversource has an internally approved project to expand Burlington Substation #391 with a 50 MVA 115/13.8kV mobile transformer bank and related upgrades. The need for the mobile transformer installation at Burlington Substation is based on Burlington Substation approaching 94% of capacity. The installation of the mobile 50 MVA transformer at Burlington Substation would be an interim measure to permit the Company additional time to develop, design, site and permit, and construct a new supply resource in the Burlington-Woburn area to address long-term capacity and reliability concerns in the area.

[63] Refer to Footnote 47 in Section 4.3.7

- **Towns of Holliston, Medway, Millis, and Norfolk: Medway Substation Upgrades -** Eversource has an internally approved project to upgrade Medway Substation #65. The project would replace both existing 40 MVA transformers with new 37/50/62.5 MVA 115/13.8kV transformers, with new sections of 13.8kV switchgear. The need for the upgrade of Medway Substation #65 is based on forecasted 2023 loading approaching 93% of capacity. The project has in in-service-date of end of year 2023.

4.4.8. Aging Infrastructure

4.4.8.1 Substation Transformers

Please refer to Section 4.3.8.1 Substation Transformers

4.4.8.2 Breakers

Please refer to Section 4.3.8.2 Breakers.

4.4.8.3 Reclosers

Please refer to Section 4.3.8.3 Reclosers.

4.4.8.4 Poles

Out of the 104,579 poles in EMA-North Metro West, the Company is the custodian of 61,094 poles. The ages of the poles with associated classes are shown in Table 15 below. There are 29,642 poles (49% of the population) that are Class 1 and 2 poles. For the results of the effective age calculation for EMA poles, please refer to Section 4.3.8.4.

Table 15: EMA-North Metro West Pole Age and Associated Class

Age	1	2	3	4	5	6	8	9	H1	H2	H4	H5	H6	NULL	NA	UNK
<=10	401	3531	707	2701	166	34	0	0	0	0	1	1	0	5	47	19
(10,20]	110	8384	728	307	33	1	0	0	0	2	0	0	0	0	11	38
(20,30]	49	6276	563	68	11	1	0	0	2	0	0	0	0	0	17	48
(30,40]	146	4592	4657	364	30	2	0	0	0	1	0	1	0	0	95	276
(40,50]	247	2099	3645	1023	61	12	0	0	1	0	0	2	0	0	42	392
>50	243	3151	7642	5382	895	62	0	0	1	2	0	0	0	0	2	345
NULL	19	394	625	303	61	4	0	0	0	0	0	0	0	0	0	13

4.4.9. Reliability and Resilience

Section 4.1.9 above includes definitions of commonly used reliability metrics and definitions of blue-sky and all-in performance measures.

4.4.9.1 Blue-sky Reliability Performance

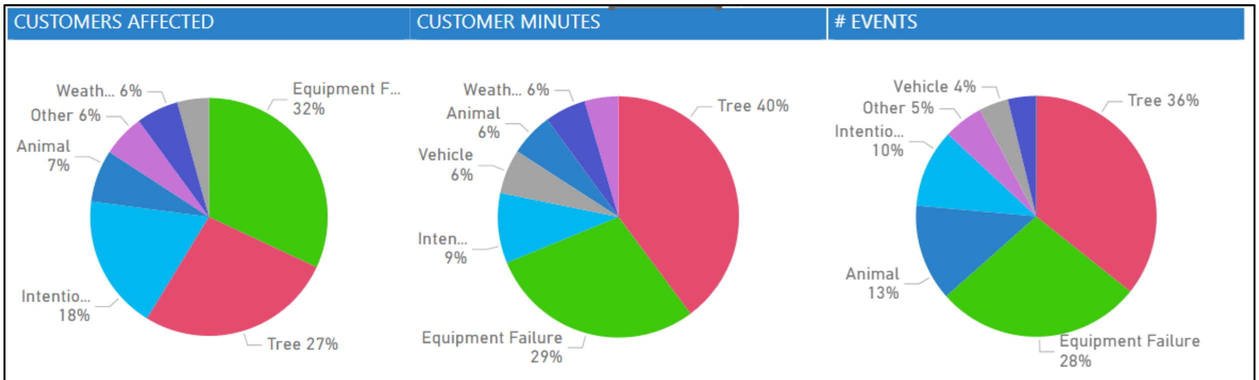
The blue-sky SAIDI in EMA-North Metro West dipped to 53.2 minutes in 2022. SAIFI also decreased to 0.61 in 2022, resulting in a corresponding dip in CAIDI values down to 86.7. Compared to the utilities participating in the 2022 IEEE Benchmark Survey (shown earlier in Section 4.1.9, Table 1), the Metro West SAIDI, SAIFI and CAIDI are all in the first quartile.

Table 16: EMA-North Metro West Blue Sky Performance

Metric	2020	2021	2022
SAIDI	71.4	72.9	53.2
SAIFI	0.77	0.72	0.61
CAIDI	91.8	100.6	86.7

The following graphs and tables show the reliability performance in EMA-North Metro West over the past three years (2020-2022). A total of 61,327,441 Customer Minutes of Interruption (CMI) were experienced in 2020-2022. These results show the reliability performance, meaning the duration and frequency of outages during blue-sky days, i.e., excluding major exception days due to major storms.

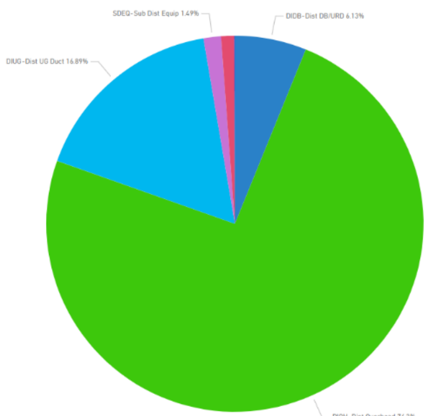
- The two leading cause of outages in terms of, customers interrupted (CI), customer minutes interrupted (CMI) and event counts are Trees and Equipment Failure as shown in Figure 41. Both of these collectively account for over 50% of CI, CMI and events. Specifically, tree-related outages account 40% of CMI, 27% of CI and 36% of events and Equipment failures account for 29% of CMI, 32% of CI and 28% of events. This is not surprising considering the combination of overhead and underground construction in the EMA-North Metro West sub-region.
- Animal and vehicle outages were also contributing significantly to outages in EMA-North Metro West from 2020 to 2022. Specifically, animal-related outages make up 6% of the CMI, 7% of the CI and 13% of the events, while vehicle-related outages make up 6% of the CMI, 4% of the CI and 4% of the events.
- Intentional Operations is another category that had significant contributions to the three metrics used to quantify blue-sky performance, making up 9% of the CMI, 18% of the CI and 10% of the events.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	46,612	3,557,469	85.72	1042
Equipment Failure	210,238	17,796,959	156.68	2231
Intentional Operation	120,798	5,757,754	66.04	844
Other	37,886	2,790,711	145.14	428
Tree	176,201	24,403,218	237.54	2871
Vehicle	28,419	3,643,053	195.30	318
Weather/ Lightning	37,822	3,378,277	218.24	306
Total	**657,976**	**61,327,441**	**171.05**	**7930**

Figure 41: Leading Causes of Blue-Sky Outrages in the EMA-North Metro West Sub-Region

The following table and chart show a further decomposition of the equipment-related outages in the EMA-North Metro West system from 2020 to 2022. The system is heavily overhead, hence the prominence of interruptions on the overhead system shown in the table and chart below.



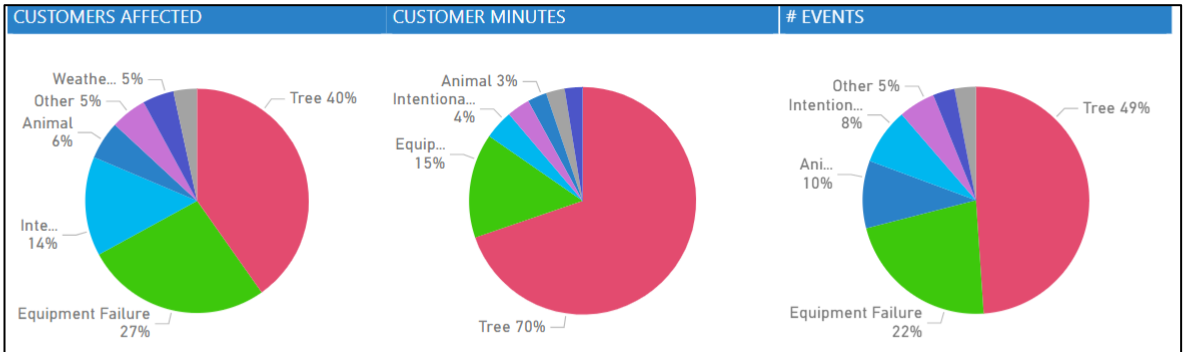
2023 Equipment Failure Types

EQUIPMENT_FAILURE	EVENTS	CUST_AFF	CMI
ASTR-Arrester	27	4,497	220,868
BUSH-Bushing	6	66	12,021
CARM-Crossarm	23	2,676	254,964
CBKR-S/S Breaker	53	32,748	2,657,377
CNTR-Connector/Clamp	160	9,476	642,877
CONS-Conductor Sec	250	1,903	232,151
COUT-Cutout	462	10,960	907,407
CPTR-Capacitor	1	58	9,454
DIDB CONP-Conductor Pri	167	3,818	640,284
DIOH CONP-Conductor Pri	370	87,316	7,313,412
DIUG CONP-Conductor Pri	155	21,404	1,791,806
ELBW-Elbow	4	317	40,127
INSL-Insulator	15	3,608	191,540
MTR-Metering	22	37	4,382
NAPP-Not applicable	2	39	3,597
OTHR-Other	20	3,200	207,438
POLE-Pole/Structure	23	4,941	374,094
RECC-Recloser Cntrl	2	30	5,580
RECL-Recloser	5	710	61,283
SDEQ CONP-Conductor Pri	2	1,682	41,443
SECT-Sectionalizer	4	1,198	102,608
SPAC-Spacer	6	2,307	257,107
STEQ CONP-Conductor Pri	1	18	1,152
SWCH-Switch/Discnt	32	7,789	585,216
TERM-Terminator	2	9	965
TIES-Tie (Insul)	1	1	259
UNKW CONP-Conductor Pri	2	72	11,371
UNKW-Unknown	2	334	27,058
XFMR-Transformer	431	9,024	1,199,118
Total	**2231**	**210,238**	**17,796,959**

Figure 42: Breakdown of Equipment-Related Outages for EMA North Metro West Sub-Region

4.4.9.2 All-In Performance

As discussed earlier in Section 4.3.9, variants of the above metrics can be used to quantify the resilience of the grid. Specifically, Eversource reports the all-in performance that includes major exception days. The all-in CMI from 2020-2022 is 154,231,401. This is about 2.5 times larger than the aforementioned blue-sky CMI that is indicative of multiple excluded days and therefore multiple severe storms present in the period reported. Figure 43 below shows the breakdown of causes of customers impacted, CMI and number of events for the all-in performance. Tree-related interruptions impact is significantly increased in all-in numbers compared to blue-sky numbers as expected. This is discussed at length later in this report in terms of the worsening impacts of climate change on vegetation and vegetation-related outages.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	49,089	4,220,446	90.52	1055
Equipment Failure	239,579	22,904,809	190.60	2428
Intentional Operation	127,639	6,404,572	69.96	879
Other	46,474	5,036,093	263.06	573
Tree	358,659	107,607,830	590.78	5372
Vehicle	30,490	4,126,839	204.99	334
Weather/ Lightning	40,268	3,930,812	275.95	341
Total	**892,198**	**154,231,401**	**369.05**	**10850**

Figure 43: Leading Causes of All-In Outrages in the EMA-North Metro West Sub-Region

4.4.10. Siting and permitting

Siting and permitting of in EMA-North Metro West MA face similar challenges to the Commonwealth as a whole, as outlined in Section 5.3.10.

4.5. EMA-South Sub-Region

The Eversource EMA-South Region consists of all or parts of forty (40) Towns and Cities in Southeastern Massachusetts (SEMA). The region consists of the City of New Bedford and surrounding Towns in the Southern portion of Bristol County, the Town of Plymouth and surrounding Towns in the Southern portion of Plymouth County, all of Cape Cod (Barnstable County), and all of Martha's Vineyard (Dukes County). Some Towns served are jointly served with National Grid (Westport, Scituate, and Pembroke) or Municipal Electric Departments (Lakeville). The service area encompasses a population of approximately 417K customer accounts. This sub-region has the largest DER penetration for solar and solar coupled with storage with a total DER from all sources of approximately 660 MW.

This sub-region consists of moderate to low load density areas. Parts of the Eversource New Bedford District has industrial and heavy commercial load within the City of New Bedford itself and within the New Bedford Business Park. Parts of the service area are highly rural protected areas with little, if any, customer density (e.g, Myles Standish State Forest in Plymouth, the Freetown-Fall River State Park, the Nickerson State Park, the Manuel F. Correllus State Forest, and various Cedar Swamps in Dartmouth, Freetown, and New Bedford). Parts of the Eversource Plymouth District and practically all the Cape District and Martha's Vineyard have high seasonal summer peak loads due to its tourist-based economy. The entire area is historically summer peaking with peaks set during heat wave events coincident with the Summer travel season. The EMA-South Region peak can be noncoincident with (set on a different day or time) than the rest of the Eversource system due to the nature of the load served.

The EMA-South Region consists of 29 bulk distribution supply substations, that step voltage down from 115kV to either 13kV or 23kV depending on the operating District, with a peak electric demand of approximately 1.2 GW in 2023. There are additional fifty-five (55) "5kV class"[64] distribution non-bulk substations, supplied from the bulk distribution substation, totaling 203 MVA of capacity which serve a subset of the EMA-South load in each District. These non-bulk stations are slowly being phased out with conversions to higher distribution voltages due to load growth, reliability performance, age of equipment, and condition assessment. In some cases, the Company is deploying 2500-kVA pad-mount transformers to replace legacy 5kV station equipment.[65]

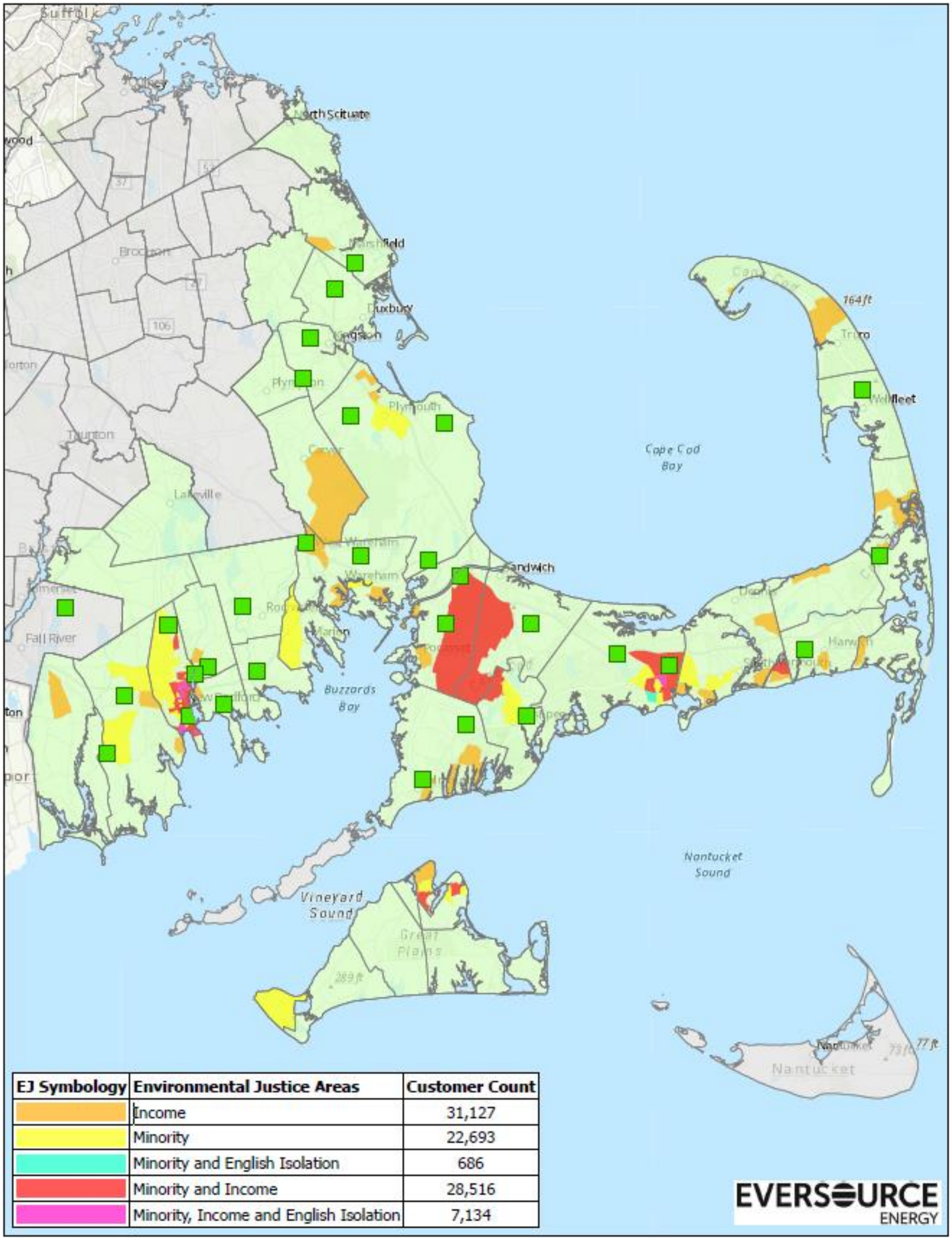
[64] "5kV Class" Substations include 23/4.16kV, 23/8.32kV, 23/4.8 kV delta, and 13.2/3.74kV voltage levels. These are vintage legacy assets of Eversource predecessor companies and have limited compatibility with each other stations.
[65] Because the amount of 5kV equipment is still significant, this approach is typically implemented in areas that are difficult to convert and will require a substantial time and capital to fully eliminate and convert to higher distribution voltages.

4.5.1. Maps

Figure 44 shows the boundaries of municipalities that comprise the Eversource planning sub-region of EMA-South shaded in light green as a base layer. The service territory is bounded by National Grid to the West.

The map includes an overlay of the EJ population in EMA-South shaded by type. This is discussed further in Section 4.5.2.2 below.

The locations of Eversource bulk distribution substations that supply areas of EMA-South are depicted as green squares. As previously mentioned in Section 4.1.2, the South area is a suburban and rural area of medium to low load density, requiring fewer and smaller 115/13.2 kV and 115/23kV bulk distribution substations to serve the load, with longer and fewer distribution feeders. The Plymouth and Cape Districts are 23kV distribution systems, requiring even fewer bulk distribution substations to serve the load than 13.2kV distribution system in the New Bedford District. The City of New Bedford has a small 208/120 Volt secondary network in the Downtown area served out of one substation.



EJ Symbology	Environmental Justice Areas	Customer Count
	Income	31,127
	Minority	22,693
	Minority and English Isolation	686
	Minority and Income	28,516
	Minority, Income and English Isolation	7,134

Figure 44: EMA-South Sub-Region Showing Substation and EJ Community Locations

4.5.2. Customer Demographics

Understanding the customer demographics of a region is essential to understanding not only how regions are expected to develop in the future as the system electrifies, but also to understanding how the customer base in the regions has historically been developing.

4.5.2.1 Customer Count

The EMA-South Sub-region consists of 385,242 customer accounts, with an approximate breakout by zip code as shown in Figure 45 below.

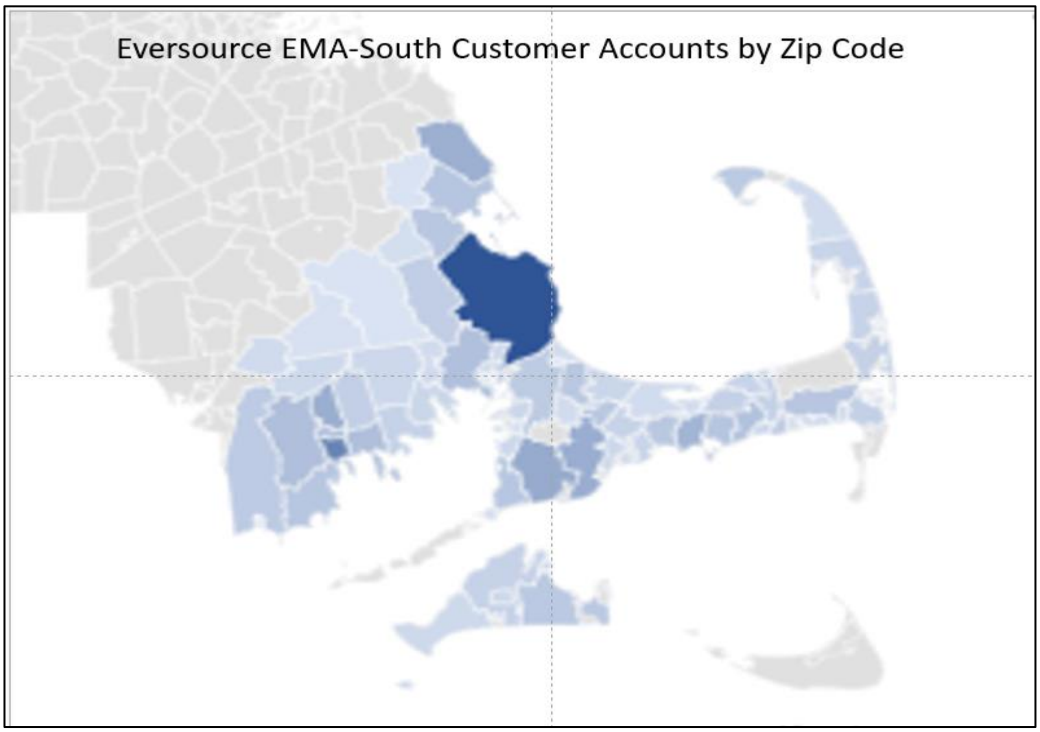


Figure 45: EMA-South Sub-region Eversource Accounts

The color in the figure has been adjusted to that the zip code with the largest numbers of accounts is darker and the zip code with the least numbers of account is a lighter shade of blue, with the darkest color being the zip code with the most customer accounts. It must be noted that in some cases, some customers will have more than account depending on their electric consumption.

4.5.2.2 Environmental Justice Communities

Figure 44 (in Section 4.5.1, Maps) shows an overlay of the EJ population in the EMA-South region derived from the Environmental Justice[66] (EJ) Map Viewer.[67] The EJ Map Viewer is an interactive map that displays the 2020 EJ block groups based upon demographic criteria developed by the state's Executive Office of Energy and Environmental Affairs (EEA). As shown, all MA 2020 Environmental Justice Block Groups, especially Income (brown), Minority (yellow), and Minority and Income (red) are well represented in this sub-region. The number of customers in each EJ block is shown in the legend. Eversource bulk distribution substations (green squares) are geographically dispersed across the sub-region, in both EJ and non-EJ communities, based primarily on load density.

4.5.2.3 Electrification Customer Classification

In order to better understand how regional adoption of electrification will play out, the Company has reviewed its customer data and identified socioeconomic variables relating to a customer's propensity to adopt heat pumps and electric vehicles. With specific variables driving electrification more than others, variables were ranked in order of importance and then a total score was calculated for each customer by summing their variable rankings. This allowed the Company to assign a priority score to each customer, which was then used to segment the customers into adoption clusters which represented their propensity to adopt both heat pumps and electric vehicles. A detailed accounting of the respective variables and their impact on the adoption propensity modeled by the Company can be found in Section 8.2.2 and Section 8.3.2.

For heat pumps, Eversource segmented the customer into 6 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, Cluster V, and Cluster VI. For electric vehicles, Eversource segmented the customers into 5 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, and Cluster V. Respectively in order of their likelihood to adopt the technologies. Figure 46 shows the customer make up by cluster type for the sub-region. From the figure Eversource can determine that 20% of customers have the highest propensity in Cluster I to adopt heat pumps (with 45% in Clusters I and II), while only 5% have the highest propensity in Cluster I to adopt electric vehicles (with 23% in Clusters I and II). Additionally, only 12% of customers fall into Cluster VI, the lowest adoption propensity for heat pumps (with 25% in Clusters V and VI) and 16% fall into the lowest adoption propensity, Cluster V, for electric vehicles (with 59% in Clusters IV and V).

[66] See Footnote 19 in Section 4.3.2.2
[67] See Footnote 20 in Section 4.3.2.2

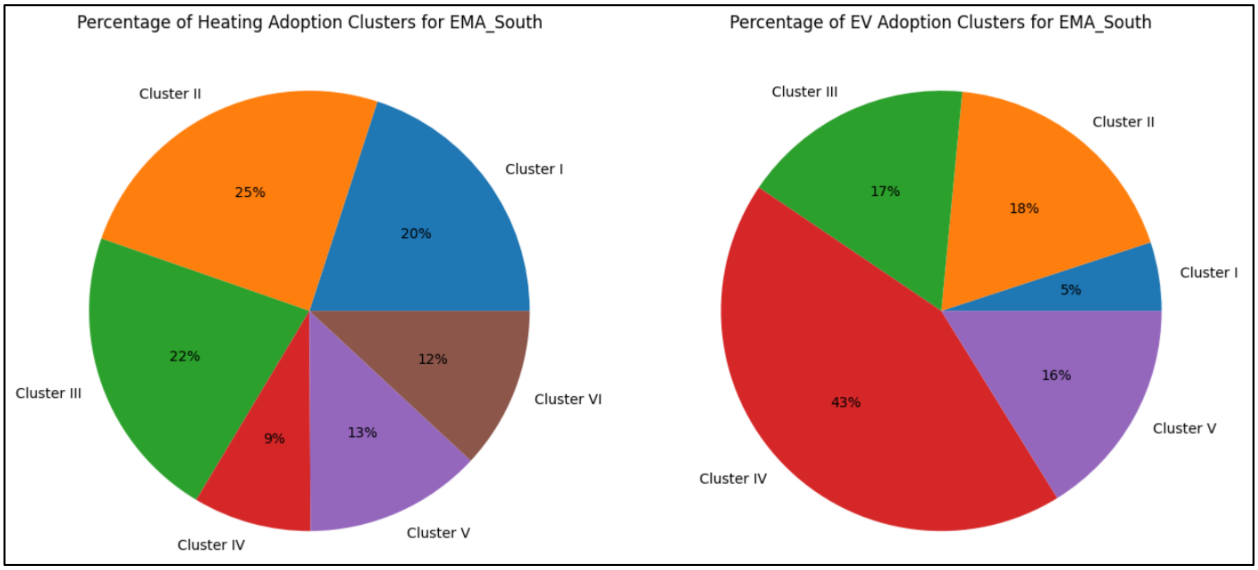


Figure 46: Cluster Percentages for a) heating adoption and b) electric vehicle adoption for EMA-South

4.5.3. Economic Development

The Eastern Massachusetts (South) Gross Metropolitan Product (GMP) [68] as shown in Table 17 below has averaged just under one percent growth over the last ten years and has more than recovered after over a four percent decline due to the pandemic in 2020. Real Household Income has maintained just under one and a half percent growth over the last ten years. Income decreased in 2022 as the effects of stimulus packages diminished; however, Income has begun to increase again and remains elevated above pre-pandemic levels. After a sizable 9.5% hit due to the pandemic, Total Employment has nearly rebounded to pre-pandemic levels and maintains an average 0.4% growth over the last ten years, with an average of nearly 3% growth in the last three years. The Unemployment Rate has continued to drop, at an average rate of 6.6%, over the last ten years, despite almost tripling in 2020. Housing Starts continue to be variable but have maintained 2.5% average growth in the last ten years.

[68] The market value of all goods and services produced in the region. GMP is the regional equivalent of the Gross Domestic Product (GDP), which measures the nation's economy

Table 17: EMA South Sub – Region Historic Economic Development

	Eastern MA South Economic Statistics*									
	Gross Metro Product		Real Household Income		Total Employment		Unemployment Rate		Housing Starts	
2014	88		112,493		806		7.5		2,244	
2015	89	1.3%	113,882	1.2%	815	1.1%	6.0	-25.0%	2,360	4.9%
2016	90	0.6%	114,269	0.3%	825	1.2%	5.2	-17.0%	3,081	23.4%
2017	90	0.3%	116,595	2.0%	832	0.9%	4.6	-10.9%	3,025	-1.9%
2018	90	0.3%	118,068	1.2%	838	0.7%	4.2	-10.2%	3,095	2.3%
2019	92	1.4%	123,160	4.1%	842	0.4%	3.7	-13.8%	2,557	-21.0%
2020	88	-4.3%	131,481	6.3%	769	-9.5%	9.9	62.5%	2,666	4.1%
2021	93	6.0%	135,090	2.7%	802	4.1%	5.9	-68.0%	2,928	9.0%
2022	94	1.2%	127,032	-6.3%	831	3.6%	3.9	-52.5%	2,866	-2.2%
2023	95	0.7%	128,876	1.4%	840	1.0%	3.8	-1.2%	2,878	0.4%
CAGR '14-'23		**0.8%**		**1.4%**		**0.4%**		**-6.6%**		**2.5%**
**Source: Moody's Analytics data for Barnstable, MA and Providence, RI*										

4.5.4. Electrification Growth

Electrification of key energy sectors, mobility and heating, has already been taking place over the past decade, albeit at a relatively slow pace. Currently, there is no mandatory reporting of electrification efforts unless customers utilize programs through Mass Save or tap into other funding sources. Therefore, existing electrification numbers are likely undercounting actuals.

4.5.4.1 Heating Electrification

Over the 2019-2023 period, 2,708 homes in the EMA-South Sub-Region received incentives via the Mass Save programs for the installation of heat pumps to replace fossil fuel heating systems. Of those, 1,861 were replacing oil or propane, and 847 were replacing gas. Eversource notes that under the current Mass Save framework, electrification incentives for customer replacing pipeline gas heating systems are provided by their gas LDC; as a result, Eversource electric does not currently have insight into how many heat pumps were installed at homes that have non-Eversource gas service. Additionally, there may be some heat pump installations that occurred without pursuing a Mass Save incentive, though this number is likely to be small given the generous nature of the incentives.

4.5.4.2 Electric Vehicles

Table 18 shows the current EV count of all Light Duty Vehicles by city in this sub-region. The data highlights the fact that EV deployment in this sub-region is still in the nascent stage, accounting for only 1% of all vehicles in the region. The total of over 5,800 EV represents less than a quarter of the Commonwealth's 2050 goal for the region.

Table 18: Current EV Count by City for EMA-South

EMA South- Municipality	EV Count (1/1/2023)	EV as a % of All Vehicles	2025 All Options Goal
Acushnet, Massachusetts	45	1%	4.3%
Aquinnah, Massachusetts	23	4%	
Barnstable, Massachusetts	439	1%	
Bourne, Massachusetts	152	1%	
Brewster, Massachusetts	126	1%	
Carver, Massachusetts	38	1%	
Chatham, Massachusetts	108	1%	
Chilmark, Massachusetts	77	4%	
Dartmouth, Massachusetts	235	1%	
Dennis, Massachusetts	135	1%	
Duxbury, Massachusetts	254	2%	
Eastham, Massachusetts	66	1%	
Edgartown, Massachusetts	150	2%	
Fairhaven, Massachusetts	93	1%	
Falmouth, Massachusetts	458	1%	
Freetown, Massachusetts	50	1%	
Harwich, Massachusetts	128	1%	
Kingston, Massachusetts	100	1%	
Lakeville, Massachusetts	90	1%	
Marion, Massachusetts	95	2%	
Marshfield, Massachusetts	155	1%	
Mashpee, Massachusetts	143	1%	
Mattapoisett, Massachusetts	95	1%	
Middleborough, Massachusetts	103	1%	
New Bedford, Massachusetts	187	1%	
Oak Bluffs, Massachusetts	92	1%	
Orleans, Massachusetts	118	2%	
Pembroke, Massachusetts	102	1%	
Plymouth, Massachusetts	528	1%	
Plympton, Massachusetts	20	1%	
Provincetown, Massachusetts	84	2%	
Rochester, Massachusetts	51	1%	
Sandwich, Massachusetts	197	1%	
Scituate, Massachusetts	213	1%	
Taunton, Massachusetts	189	1%	
Tisbury, Massachusetts	93	2%	
Truro, Massachusetts	44	2%	
Wareham, Massachusetts	126	1%	
Wellfleet, Massachusetts	57	1%	
West Tisbury, Massachusetts	79	2%	
Westport, Massachusetts	136	1%	
Yarmouth, Massachusetts	155	1%	
Total	**5,829**	**1%**	

4.5.5. DER Adoption (Battery Storage and PV Solar)

The Eversource EMA-South area has a significant DER penetration for solar and solar coupled with battery storage and has the largest share of solar applications in the EMA area due to the larger proportion of open space in this part of the Company's service territory, and due to the nature of incentives that are available. The categories of DER interconnecting in the EMA-South sub-region include behind-the-meter (BTM) battery storage, Combined Heat and Power (CHP) cogeneration, fuel cells, fuel cells coupled with battery storage, gas turbine generators, hydro, internal combustion (diesel) engines, microturbines, standalone and BTM solar, solar coupled with battery storage (both AC and DC coupled), steam turbine, and wind turbines.

As shown in Figure 47, the largest share of existing online DER interconnections is solar (both standalone and BTM), with and without battery storage. The current online solar total in the EMA-South area is at least 524 MW of solar only and another 86 MW of solar coupled with battery storage. Total DER including other technologies is approximately 659 MW (per latest tracking system extraction).

The EMA-South area has a significant quantity of projects with recently completed impact studies but not yet interconnected, projects participating in Group Studies, projects in queue, projects in the application stage, or projects in a prescreen stage without a format application submitted yet. These applications include: 138.8 MW of standalone BESS, 214 MW of standalone Solar, 350 MW of standalone solar coupled with BESS. Total DER in queue or in study process is 704 MW. The amount of DER deployed currently far exceeds native load growth and has become the predominant driver for substation and distribution capacity expansion needs. Based on local irradiance at historical times of peak, this aggregate (both installed and in-queue) Solar and Battery Storage build out translates to 38 MW of contribution toward North Metro Boston peak demand reduction or 3% of 2034 peak demand.

Figure 48 below describes the growth of DERs in the EMA-South area since 2010. As seen from the graph, the annual DER interconnections in the area have grown significantly in the past five years.

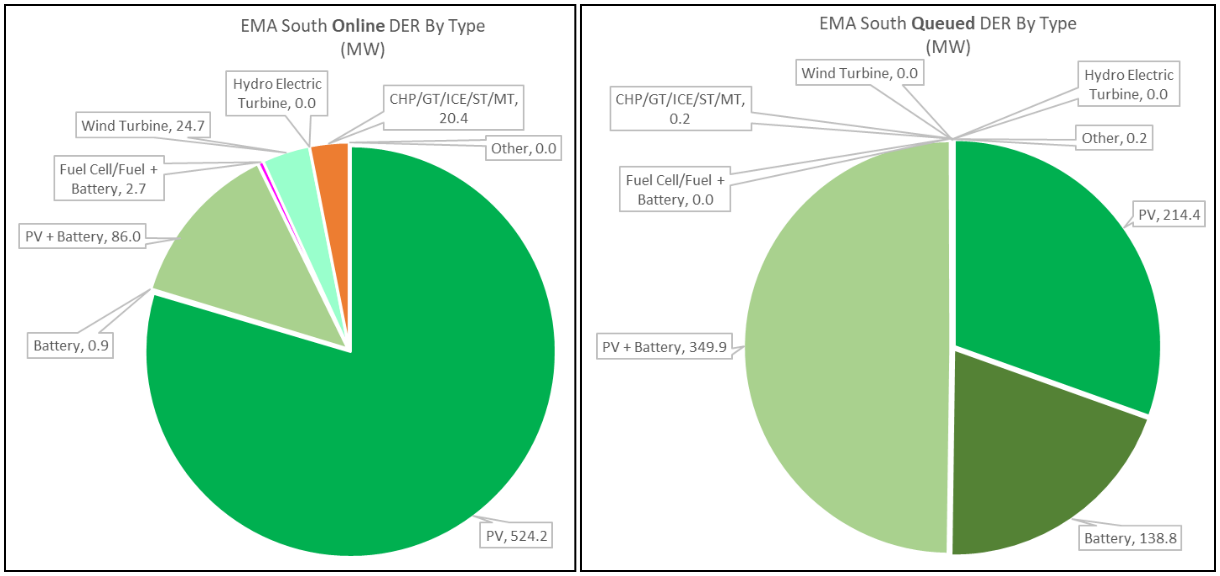


Figure 47: EMA-South Online DER and Queued DER by Technology (MW by Type)[69]

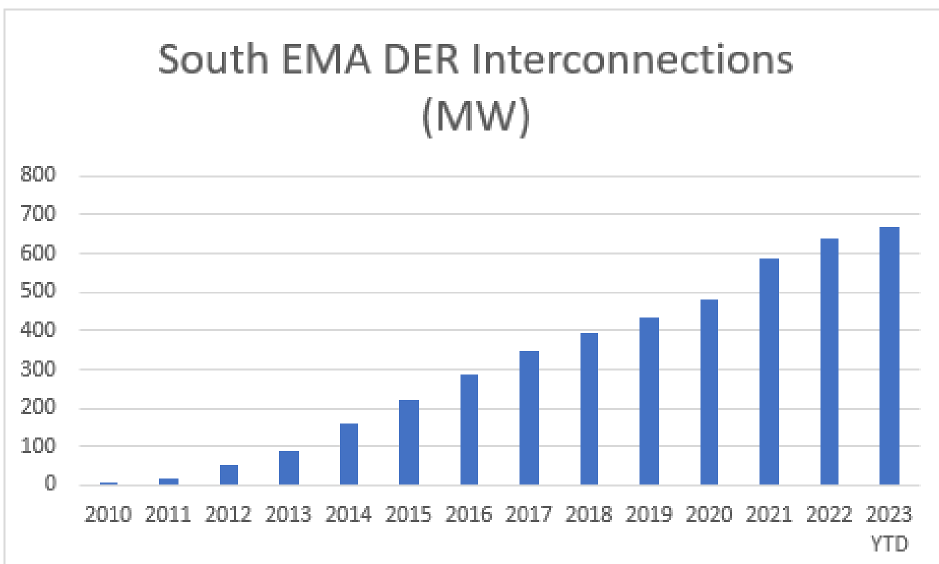


Figure 48: WMA Annual DER Interconnections

Similar to other investor-owned utilities in the Commonwealth, Eversource previously used a first-in, first-out (queued) approach to DER interconnection, with cost causation; meaning, the applications were processed for impact studies in the order received (by substation area) and

[69] The CHP/GT/ICE/ST/MT category includes combined heat and power (CHP), gas turbine (GT), internal combustion engine (ICE), steam turbine (ST) and microturbine (MT) applications.

the applicant paid for system upgrades to address the impacts that their particular applications caused. Due the large influx of applications, many of them queued for the same substations and towns, this resulted in a significant backlog of applicants. In some cases, applicants were waiting in queue for several years.

Under MA DPU dockets 17-164, 19-55, 20-75, and 20-75-B, Eversource and other stakeholders cooperated with the Department to develop a framework to perform Group studies at saturated substations, in order to develop more comprehensive solutions, and to propose and obtain approval for alternative cost allocation proposals. As a result, Eversource performed a total of seven Group Studies (six in SEMA) involving multiple substations and multiple project owners, to develop comprehensive solutions for the group study DER and developed an innovate first-in-the nation cost allocation methodology to equitably share the cost for common system modifications between the beneficiaries: developers and distribution customers. Pursuant to the 20-75-B Provisional DER Program Order, the Company filed Capital Investment Project (CIP) proposals for six of the seven group study solutions that met the eligibility requirements for the Provisional Program. The six proposals were then adjudicated by the Department under six separate dockets: DPU 22-47 (Marion-Fairhaven), DPU 22-51 (Freetown), DPU 22-52 (Plainfield-Blandford, a WMA project), DPU 22-53 (Dartmouth- Westport), DPU 22-54 (Plymouth), and DPU 22-55 (Cape Cod). The New Bedford Group (Industrial Park station) CIP was not submitted as the CIP fee exceeded the $500/kW threshold set by the Department in the Provisional Program Order. As of this time, DPU 22-47 has been approved by the Department, and a decision on the remaining five CIPs is expected in the third quarter of 2023.

Assuming the Department approves the remaining four EMA-South CIP dockets, the Company must upgrade nine distribution bulk substations and 17 substation transformers (with associated distribution system upgrades), construct three new 115kV transmission lines, and upgrade one existing 115kV transmission line, all within four years of receipt of the approval order, as stipulated in the Provisional Program Order. Some of this work will require additional EFSB and DPU approval through Chapter 40A, 72D, and EFSB 69J regulatory petitions.

Following successful completion of the Group Studies, the Company has standardized on Group Studies as an approach to expedite interconnection studies in all Planning Regions. The Company's foundational assumption is that Cost Allocation methodologies such as those proposed under 20-75-B and approved under 22-47 will be applicable to Group Study solutions going forward to avoid some of the known disadvantages of the cause causation principle, including queue stagnation and free rider issues, especially at saturated substations.

4.5.6. Grid Services

4.5.6.1 Demand Response

In 2022, there were 7.9MW of savings from Active Demand Response delivered through the Mass Save program[70] in the South Sub-Region.

4.5.6.2 Smart Inverter Controls

See Section 4.3.5.2.

4.5.6.3 Time-varying Rates

The Eversource EMA-South area falls within Eversource's South service area which encompasses the South Shore, Cape Cod and Martha's Vineyard. The municipalities in this area are subject to rates that originated under the legacy Commonwealth Electric Company, so pricing is distinct from the Greater Boston and Cambridge service areas. TOU rates are available for medium to large general service customers. These customers fall under the Rate G-2 or Rate G-3 customer classes. Rate G-2 customers are greater than 100 kW while Rate G-3 customers are greater than 500 kW.

TOU rates are on the delivery side only and demand based. This means that demand is assessed to the highest metered demand with a floor on the demand that varies by rate class. TOU definitions in the South are the same as in Cambridge where it is divided into a Peak, Low Load A, and Low Load B. Peak is defined as 9 am to 6 pm weekdays when eastern daylight savings time is in effect and 4 pm to 9 pm weekdays when eastern standard time is in effect. Low Load B is defined as 10 pm to 7 am weekdays and all hours on weekends during both eastern daylight savings and eastern standard time. Low Load A is defined as all hours not included in the Peak or Low Load B periods.

4.5.6.4 Energy Efficiency

In 2022, the Mass Save programs achieved 3.5 MW of passive peak demand savings in the South region (note that for customers on the Cape, Mass Save is delivered by the Cape Light Compact).

---

[71] See Footnote 41 in Section 4.3.7

4.5.7. Capacity deficiency

The Company's planning process, including development of solutions for capacity and reliability needs, is discussed in detail in Section 4.1.

In medium to low load density areas, such as the EMA-South Sub-Region, a higher degree of reliability is ensured by maintaining sufficient capacity such that the system can be operated without the permanent loss of power to customers following the loss of a transformer at a substation – also known as N-1 Contingency Design.[71]

Through its annual capacity planning processes, as summarized in Section 4.1, and reported in the ARR under DPU docket 23-ARR-02[72] and as reported in the Company's Rate Case Filing under DPU 22-22,[73] the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing capacity[74] and/or reliability[75] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations at capacity now. Table 18 below, list the communities in EMA-South and the existing or projected substation or distribution line supply deficiency by type (Reliability and/or Capacity) in the fourth column.

Table 19: EMA-South Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Bourne	Town	Barnstable	Capacity	Now/Existing
Falmouth	Town	Barnstable	Capacity	Now/Existing
Mashpee	Town	Barnstable	Capacity	Now/Existing
Aquinnah	Town	Dukes	Capacity and Reliability	Now/Existing
Chilmark	Town	Dukes	Capacity and Reliability	Now/Existing
West Tisbury	Town	Dukes	Capacity and Reliability	Now/Existing
Tisbury	Town	Dukes	Capacity and Reliability	Now/Existing
Oak Bluffs	Town	Dukes	Capacity and Reliability	Now/Existing
Edgartown	Town	Dukes	Capacity and Reliability	Now/Existing

Table 20 below shows the substation name or location in the first column, followed by the Community that is supplied by the substation. The table also shows how loaded the substation

71 See Footnote 41 in Section 4.3.7
72 See Footnote 42 in Section 4.3.7
73 See Footnote 43 in Section 4.3.7
74 See Footnote 44 in Section 4.3.7
75 See Footnote 45 in Section 4.3.7

is projected to be compared to the substation capacity[76]. Values greater than 100% in the last columns of the table is a violation of the company criteria since the transformers expected peak load will exceed the substation capacity. The impact of substation and distribution assets being "at capacity" has multiple facets. Eversource may have to employ measures like temporary load transfers to other substations, may have to install enhanced cooling on substation transformers or other equipment, may have to deploy temporary generation in response to a substation or on a distribution feeder for load relief in response to equipment outages, and the Company may be unable to interconnect new large customers short term until the "capacity deficiency" is addressed.

Table 20: EMA-South Substations with Projected Capacity Deficiency and Communities Impacted

Substation Name or Location	Community Supplied	2023 % of Capacity
East Falmouth	Bourne, Falmouth, and Mashpee	**100%**
Martha's Vineyard Distribution Supply	Aquinnah, Chilmark, West Tisbury, Tisbury, Oak Bluffs, and Edgartown	**150%**

Currently 1 out of 29 substations supplying EMA-South sub-region and four submarine cables supplying Martha's Vineyard have capacity and/or reliability violations. Through its annual capacity planning processes, as noted in the ARR, the company goal is to have a solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon. The next paragraphs describe the need and Company's plan for the substations and distribution lines systems currently at capacity (East Falmouth and Martha's Vineyard Submarine Cables).

- **Towns of Bourne, Falmouth, and Mashpee: Future Falmouth Tap Substation –** Eversource has an internally approved project to expand an existing 115kV switching station called Falmouth Tap #924 from a 115kV series bus arrangement to a 115kV breaker and a half scheme and install a new 115/23kV bulk distribution substation at this location. The need for a new bulk distribution substation at Falmouth Tap #924 is to relieve Hatchville Substation #936, which is approaching 100% of capacity at forecasted 2023 Summer peak load levels; and to improve distribution system reliability by breaking up long 23kV distribution feeders into new, shorter feeders resolve a multitude of N-1 single-contingency transmission outage events that result in load loss in excess of limits

[76] Refer to Footnote 47 in Section 4.3.7

in the Company's planning standards. The construction of a new 115/23kV bulk distribution substation at Falmouth Tap #924 has a year 2026 in-service-date.

4.5.7.1 Capacity Deficiencies due to Distribution Lines

- **Martha's Vineyard 5th Cable** – Eversource is currently in the permitting and design stages for installation of a 5th 23kV submarine cable to supply Martha's Vineyard, and to replace one of the existing cables (#91) cable with a larger new cable. The installation of both cables will address capacity issues supplying Martha's Vineyard, will permit the retirement of five vintage 2.5 MW diesel generators on the island (vintage 1940 and 1970's), and support the Martha's Vineyard Commission Climate Action Task Force (MV/CAT) goals of future electrification of fossil fuel end uses (vehicles, heating, etc.) on the island. The upgrade is expected to be complete by end of 2024.

4.5.7.2 Capacity Deficiencies due to DER Penetration[77]

- **DPU 22-47 (Marion-Fairhaven Group Study)[78] –** The Marion-Fairhaven Group comprises of four substations in Southeastern Massachusetts (SEMA): Arsene Street (Substation #654); Crystal Spring (Substation #646); Rochester (Substation #745); and Wing Lane (Substation #624). These substations collectively serve 57 MVA of customer peak load. There is a total of 60 MW of installed ground mounted (large) DER, in addition to 10 MW rooftop (small) DER on the four stations, and the Group Study will interconnect another 49 MW of large DER, bringing the total DER penetration to 209% of peak load for the group. Figure 49 below shows the approximate geographical location, in the EMA-South service area, served by the four substation substations in the group. A description of the CIP solution is included in Section 6.

Figure 49: Marion-Fairhaven DER Group Approximate Boundary

---

[77] Provisional System Planning Program Guide," Mass.gov. For more details, visit [Provisional System Planning Program Guide | Mass.gov]

[78] Refer to DPU 22-47 Exhibit ES-Engineering Panel-1; Approved by the Department December 2022

- **DPU 22-51 (Freetown Group Study)** [79] – Freetown Group Study Solution comprises of one substation in Southeastern Massachusetts (SEMA): Assonet (Substation #647). This substation is currently supplied by Bell Rock #647, a National Grid bulk substation, with an Eversource-owned 115/34.5 kV transformer that supplies two 34.5/13.2 kV 15 MVA transformers at the Assonet substation via a single 34.5 kV line. The Assonet substation serves 9 MVA of customer peak load. There is a total of 11 MW of installed ground mounted (large) DER, in addition to 2 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 22 MW of large DER, bringing the total DER penetration to 389% of peak load for the group.[80] Figure 50 below shows the approximate geographical location, in the EMA-South service area, served by the two substation substations in the group. A description of the CIP solution is included in Section 6.

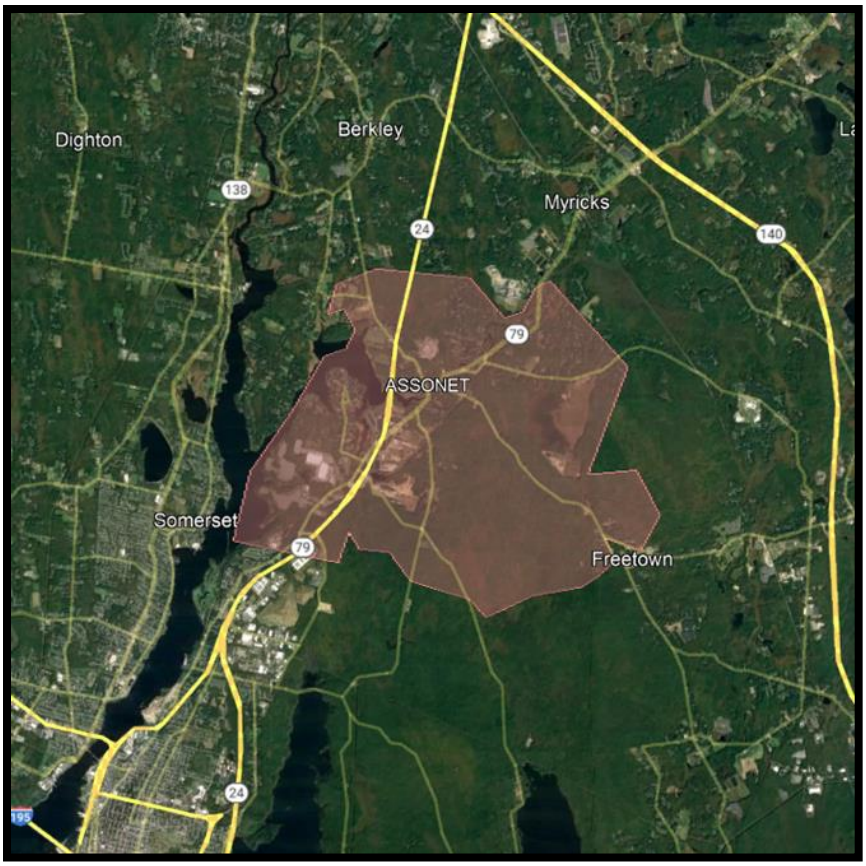


Figure 50: Freetown DER Group Approximate Boundary

[79] Refer to DPU 22-51 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023
[80] The approximately 22 MW of DER consists of 6 different facilities from 4 applicants.

- **DPU 22-53 (Dartmouth-Westport Group Study)**[81] – The Dartmouth-Westport Group Study Solution is comprised of two substations in Southeastern Massachusetts (SEMA): Cross Road (Substation #651) and Fisher Road (Substation #657). The substations collectively serve 64 MVA of customer peak load. There is a total of 61 MW of installed ground mounted (large) DER, in addition to 11 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 16 MW of large DER, bringing the total DER penetration to 136% of peak load for the group.[82] Figure 51 below shows the approximate geographical location of the two substations, and the geographic location served by the substations, in the EMA-South Service Area. A description of the CIP solution is included in Section 6.

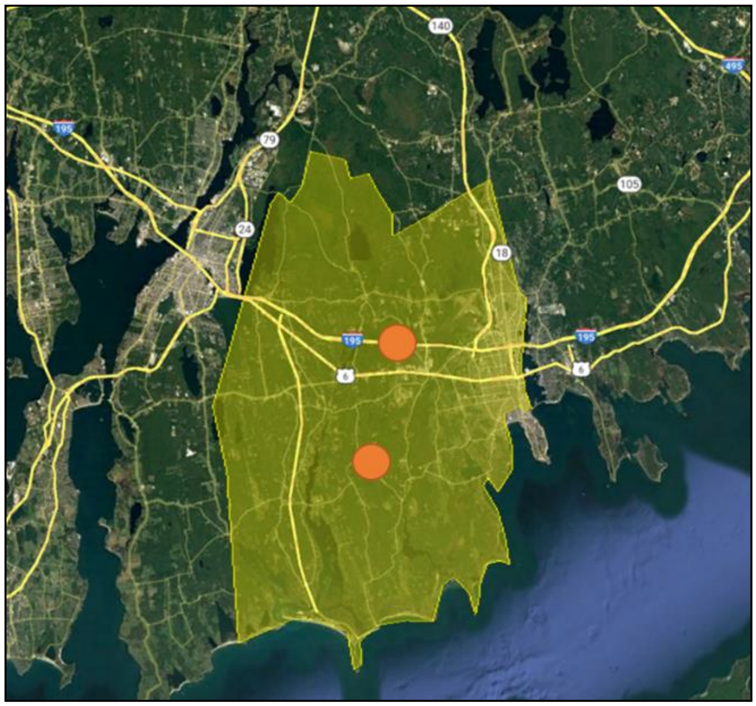


Figure 51: Dartmouth-Westport DER Group Approximate Boundary

[81] Refer to DPU 22-53 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023
[82] The approximately 16 MW of DER consists of 6 different facilities from 5 applicants.

- **DPU 22-54 (Plymouth Group Study)** [83] – The Plymouth Group comprises of seven substation in Southeastern Massachusetts (SEMA): Tremont (Substation #713), Wareham (Substation #714), West Pond (Substation #737), Valley (Substation #715), Manomet (Substation #721), Kingston (Substation #735), and Brook St (Substation #727). These substations collectively serve 229 MVA of customer peak load. There is a total of 202 MW of installed ground mounted (large) DER, in addition to 35 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 123 MW of large DER, bringing the total DER penetration to 157% of peak load for the group. Figure 52 below shows the approximate geographical location of the seven substations, and the geographic location served by the substations, in the EMA-South Service Area. A description of the CIP solution is included in Section 6.

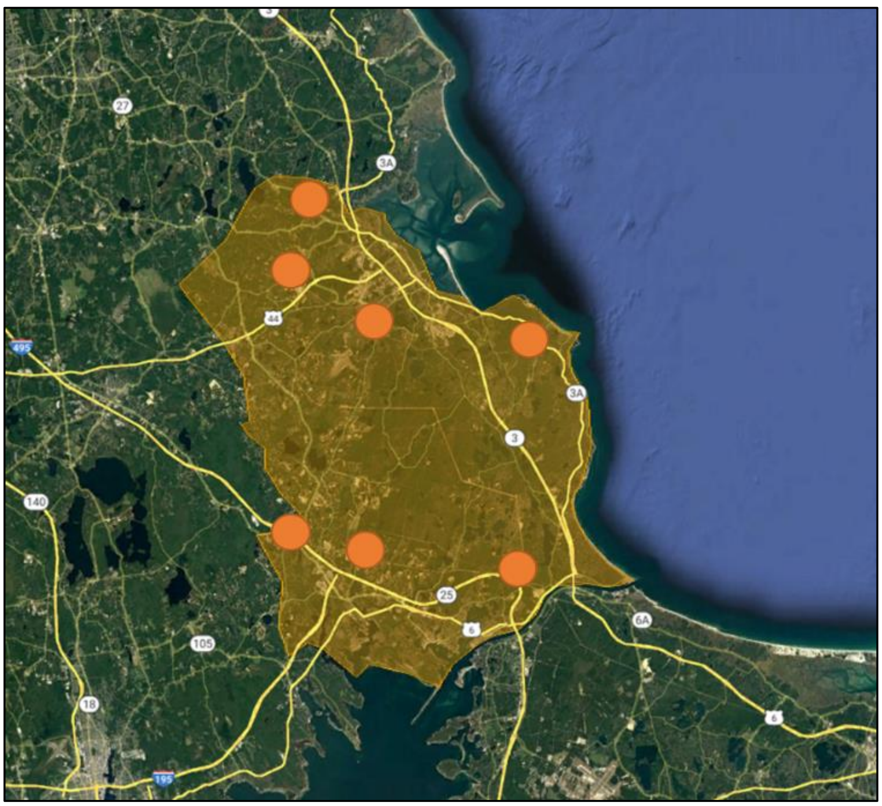


Figure 52: Plymouth DER Group Approximate Boundary

[83] Refer to DPU 22-54 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023

- **DPU 22-55 (Cape Group Study)** [84] – The Cape Group comprises of eight substations in Southeastern Massachusetts (SEMA): Falmouth #933, Harwich #968, Hatchville #936, Hyannis Junction #961, Sandwich #916, Oak St #920, Mashpee #946, and Otis #915. These substations collectively serve 461 MVA of customer peak load. There is a total of 103 MW of installed ground mounted (large) DER, in addition to 46 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 71 MW of large DER, bringing the total DER penetration to 48% of peak load for the group. Figure 53 below shows the approximate geographical location of the eight substations, and the geographic location served by the substations, in the EMA-South Service Area. A description of the CIP solution is included in Section 6.

Figure 53: Cape DER Group Approximate Boundary

[84] Refer to DPU 22-55 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023

4.5.8. Aging Infrastructure

4.5.8.1 Substation Transformers

Please refer to Section 4.3.8.1 Substation Transformers

4.5.8.2 Breakers

Please refer to Section 4.3.8.2 Breakers.

4.5.8.3 Reclosers

Please refer to Section 4.3.8.3 Reclosers.

4.5.8.4 Poles

Of the 200,067 poles in EMA South, the Company is the custodian of 104,734 poles. The ages of the poles with associated classes are shown in the Table below. There are 17,779 poles (17% of the population) that are Class 1 and 2 poles. For the results of the effective age calculation for EMA poles, please refer to Section 4.3.8.4.

Table 21: EMA South Pole Age and Associated Class

Age	1	2	3	4	5	6	8	9	H1	H2	H4	H5	H6	NULL	NA	UNK
<=10	4783	1875	1312	4088	1208	313	1	0	35	91	4	4	1	2	153	17
(10,20]	2989	782	7180	734	48	2	0	0	12	22	0	0	0	0	9	10
(20,30]	449	1559	3533	6535	59	7	0	0	14	32	0	0	0	0	70	21
(30,40]	719	2414	1576	15756	513	56	0	0	26	13	0	4	0	0	473	83
(40,50]	329	416	829	13557	679	91	0	0	6	3	0	5	0	0	341	132
>50	764	594	1185	17104	6823	390	0	0	7	1	2	33	0	0	740	156
NULL	57	49	70	661	105	13	0	0	0	0	0	0	0	0	2	3

4.5.9. Reliability and resilience

Section 4.1.9 above includes definitions of commonly used reliability metrics and definitions of blue-sky and all-in performance measures.

4.5.9.1 Blue-sky Reliability Performance

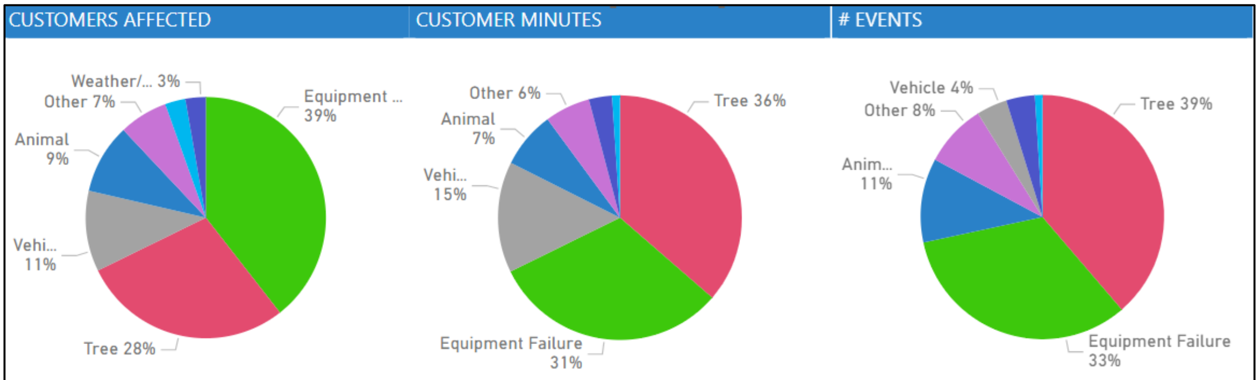
The following table summarizes the reliability performance in EMA South in 2020-2022 by means of three reliability metrics; SAIDI, SAIFI and CAIDI. While SAIDI and SAIFI are increasing throughout these three years, CAIDI had less variation from 2021 to 2022. Compared to the utilities participating in the 2022 IEEE Benchmark Survey (shown earlier in Section 4.1.9, Table 1), the EMA-South SAIDI, SAIFI and CAIDI are all in the first quartile.

Table 22: EMA-South Blue-Sky reliability Performance

Metric	2020	2021	2022
SAIDI	51.3	70.3	88.9
SAIFI	0.67	0.77	0.95
CAIDI	76.1	91.3	93.8

The following graphs and tables show the reliability performance in EMA South over the past three years (2020-2022). These results show the reliability performance, meaning the duration and frequency of outages during blue-sky days, i.e., excluding major exception days due to major storms.

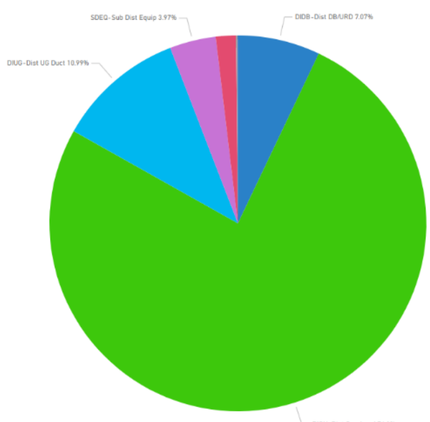
- The leading cause of outages in terms of event counts and customer minutes is tree-related outages. Specifically, tree-related outages make up 36% of the Customer Minutes of Interruption (CMI), 28% of the customers affected and 39% of the events.
- The leading cause of outages in terms of customers affected is equipment-related outages. Specifically, equipment-related outages make up 31% of the Customer Minutes of Interruption (CMI), 39% of the customers affected and 33% of the events. This means that the interruptions related to equipment causes impact a larger number of customers, as compared to tree-caused interruptions.
- Animal and vehicle outages were also contributing significantly to outages in EMA South from 2020 to 2022. Specifically, animal-related outages make up 7% of the Customer Minutes of Interruption (CMI), 9% of the customers affected and 11% of the events, while vehicle-related outages make up 15% of the Customer Minutes of Interruption (CMI), 11% of the customers affected and 4% of the events. This leads us to the conclusion that the average interruption caused by a vehicle (typically a pole crash) has more impact on customers impacted and on customer minutes of interruption.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	85,125	5,983,231	84.78	1045
Equipment Failure	358,520	25,112,985	135.17	3092
Intentional Operation	25,069	836,865	53.39	94
Other	59,581	4,812,215	130.07	781
Tree	257,944	29,089,339	190.75	3631
Vehicle	98,381	11,736,615	182.64	383
Weather/ Lightning	24,890	2,449,704	162.41	357
Total	**909,510**	**80,020,954**	**152.91**	**9325**

Figure 54: Leading Causes of Blue-Sky Outrages in the EMA-South Sub-Region

The following table and chart show a further decomposition of the equipment-related outages in the EMA South system from 2020 to 2022. The EMA South system is heavily overhead, hence the prominence of interruptions on the overhead system shown in the table and chart below.



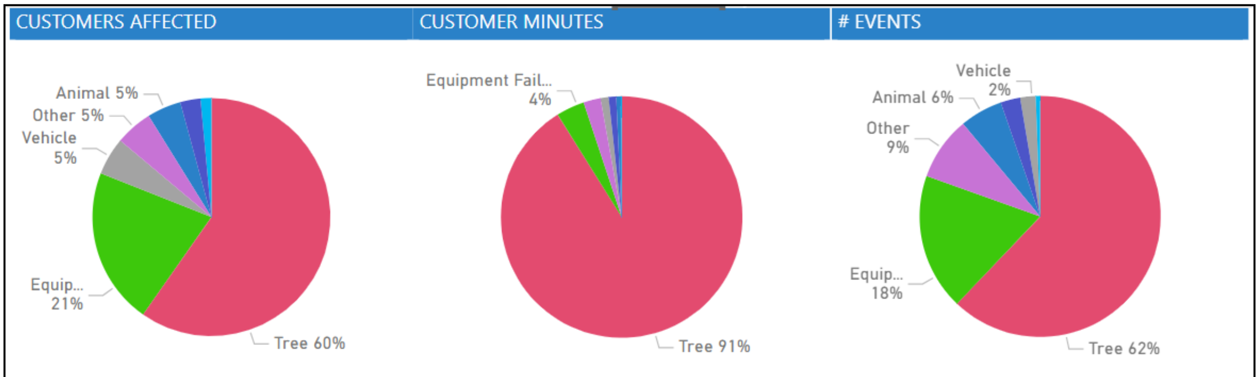
2023 Equipment Failure Types

EQUIPMENT_FAILURE	EVENTS	CUST_AFF	CMI
ASTR-Arrester	26	2,552	107,118
BUSH-Bushing	9	1,770	85,944
CARM-Crossarm	13	1,923	210,434
CBKR-S/S Breaker	22	89,759	1,862,701
CNTR-Connector/Clamp	137	7,420	408,243
CONS-Conductor Sec	434	2,497	260,336
COUT-Cutout	857	30,506	2,286,266
CPTR-Capacitor	1	1,274	142,652
DIDB CONP-Conductor Pri	197	6,599	1,296,013
DIOH CONP-Conductor Pri	302	95,929	7,853,685
DIUG CONP-Conductor Pri	171	19,306	2,047,970
ELBW-Elbow	13	384	61,651
INSL-Insulator	49	21,629	1,656,953
MTR-Metering	4	5	985
NAPP-Not applicable	4	96	6,344
OTHR-Other	50	10,978	407,445
PFUZ-Power Fuseholder	2	633	142,144
POLE-Pole/Structure	35	8,583	1,183,571
RECC-Recloser Cntrl	6	1,387	90,757
RECL-Recloser	21	6,831	434,180
REGL-Regulator	2	1,212	65,703
RELY-Relay - S/S	1	3,238	366,821
SECT-Sectionalizer	5	2,593	189,520
SWCH-Switch/Discnt	13	17,640	1,361,500
TERM-Terminator	3	126	16,154
TIES-Tie (Insul)	16	6,635	443,407
TRAN CONP-Conductor Pri	1	3,656	32,904
UNKW-Unknown	6	1,405	215,350
XFMR-Transformer	740	11,954	1,876,234
Total	**3092**	**358,520**	**25,112,985**

Figure 55: Breakdown of Equipment-Related Outages for EMA South Sub-Region

4.5.9.2 All-In Performance

As discussed earlier, variants of the above metrics can be used to quantify the resilience of the grid. Specifically, Eversource reported the all-in performance that includes major exception days. The all-in CMI from 2020-2022 is 1,089,924,926. This is twelve-fold increase compared to the aforementioned blue-sky CMI that is indicative of multiple excluded days and therefore multiple severe storms present in the period reported. Figure 56 shows the breakdown to causes of customers impacted, CMI and number of events for the all-in performance. Tree-related interruptions impact is significantly increased in all-in numbers compared to blue-sky numbers as expected. This is discussed at length later in this report in terms of the worsening impacts of climate change on vegetation and vegetation-related outages.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	89,519	6,515,192	99.32	1070
Equipment Failure	411,568	41,205,581	206.58	3412
Intentional Operation	28,620	1,350,526	65.44	109
Other	97,631	24,888,863	405.27	1582
Tree	1,156,775	993,158,501	1,137.56	11558
Vehicle	99,136	11,814,358	184.38	388
Weather/ Lightning	53,245	10,991,905	327.32	489
Total	**1,936,494**	**1,089,924,926**	**790.00**	**18517**

Figure 56: Leading Causes of All-In Outrages in the EMA-South Sub-Region

4.5.10. Siting and Permitting

The South Sub Region is positioned to support the Commonwealth's clean energy goals by providing landing sites for offshore wind and hosting substantial construction of solar. Expanding distribution and transmission capacity will absorb the influx of clean energy. This region faces similar siting and permitting challenges as the Commonwealth as a whole, as outlined in Section 5.3.10.

Project Status

- **Falmouth Tap Substation** - This project includes a new bulk distribution substation to improve reliability. It will require a Chapter 40A filing with DPU. Preliminary design is ongoing and the project is proposed be filed in 2024.
- **Marion-Fairhaven Group Study (DPU 22-47)** - The Marion-Fairhaven capital investment project proposal, submitted under the Provisional Program, was approved by DPU on 12/30/22. The suite of projects includes upgrades to several substations and a three-mile transmission line extension. The Crystal Springs Substation and Transmission Line will require a Section 72 Determination and a Chapter 40A filing with DPU, which is anticipated

to be filed in 2024. The Wing Lane and Arsene substation work can be permitted locally. Rochester substation work may require a Chapter 40A filing.

- **Dartmouth–Westport (D.P.U. 22-53), Freetown (D.P.U. 22-51) and Plymouth (D.P.U. 22-54) Group Studies** These capital investment project proposals were filed with the DPU on 4/29/22. Reply briefs were filed on 3/23/23. No decisions have been issued to date. It is anticipated that they will be issued in the third quarter of 2023. Upon approval and subsequent design and engineering, each group will submit petitions to EFSB/DPU as applicable.

4.6. WMA Sub-Region

The Eversource Western Massachusetts (WMA) Sub-region consists of all or parts of sixty (60) Towns and Cities in Central and Western Massachusetts. The service area encompasses a population of approximately 212,000 customer accounts supplied out of 28 substations with a peak electric demand of approximately 0.9 GW in 2023. This sub-region has the second largest DER penetration for solar and solar coupled with storage with a total DER from all sources of approximately 569 MW. The region consists of the Cities of Springfield and Pittsfield and surrounding Towns in Berkshire, Hampshire, Hampden, and Franklin Counties. Some Towns served are jointly served with National Grid (Hancock, Cheshire, and Erving) or Municipal Electric Departments (Russell). This sub-region consists of high, moderate, and low load density areas. Parts of the Eversource Springfield AWC has industrial and heavy commercial load within the City of Springfield. There is overlap between Eversource- and National Grid-served areas in Western Massachusetts, in some cases with National Grid load served wholesale out of Eversource bulk distribution substations. As an example, Eversource Pleasant Substation 16B in Lee, MA, serves National Grid load at the distribution level in the Towns of Great Barrington, Alford, Egremont, Sheffield, etc. The Eversource WMA Sub-Region consists of 212,000 customer accounts.

4.6.1. Maps

Figure 57 shows the boundaries of municipalities that comprise the Eversource planning sub-region of WMA shaded in light green as a base layer. The service territory is bounded by National Grid (NY and MA) to the West, National Grid (MA) and Green Mountain Power (Vermont) to the North, Eversource (CT) to the South and National Grid (MA) to the East.

The map includes an overlay of the EJ population in WMA shaded by type. This is discussed further in Section 4.6.2.2 below.

The locations of Eversource bulk distribution substations that supply areas of EMA-South are depicted as green squares. As previously mentioned in Section 4.1.2, the Western Massachusetts area, except for the City of Springfield, is a rural area of low load density, requiring smaller 13 kV and 23kV bulk distribution substations to serve the load over a larger geographical area, with longer and fewer distribution feeders. The difference in substation density between the urban and suburban areas of Springfield versus the rural areas is readily apparent.

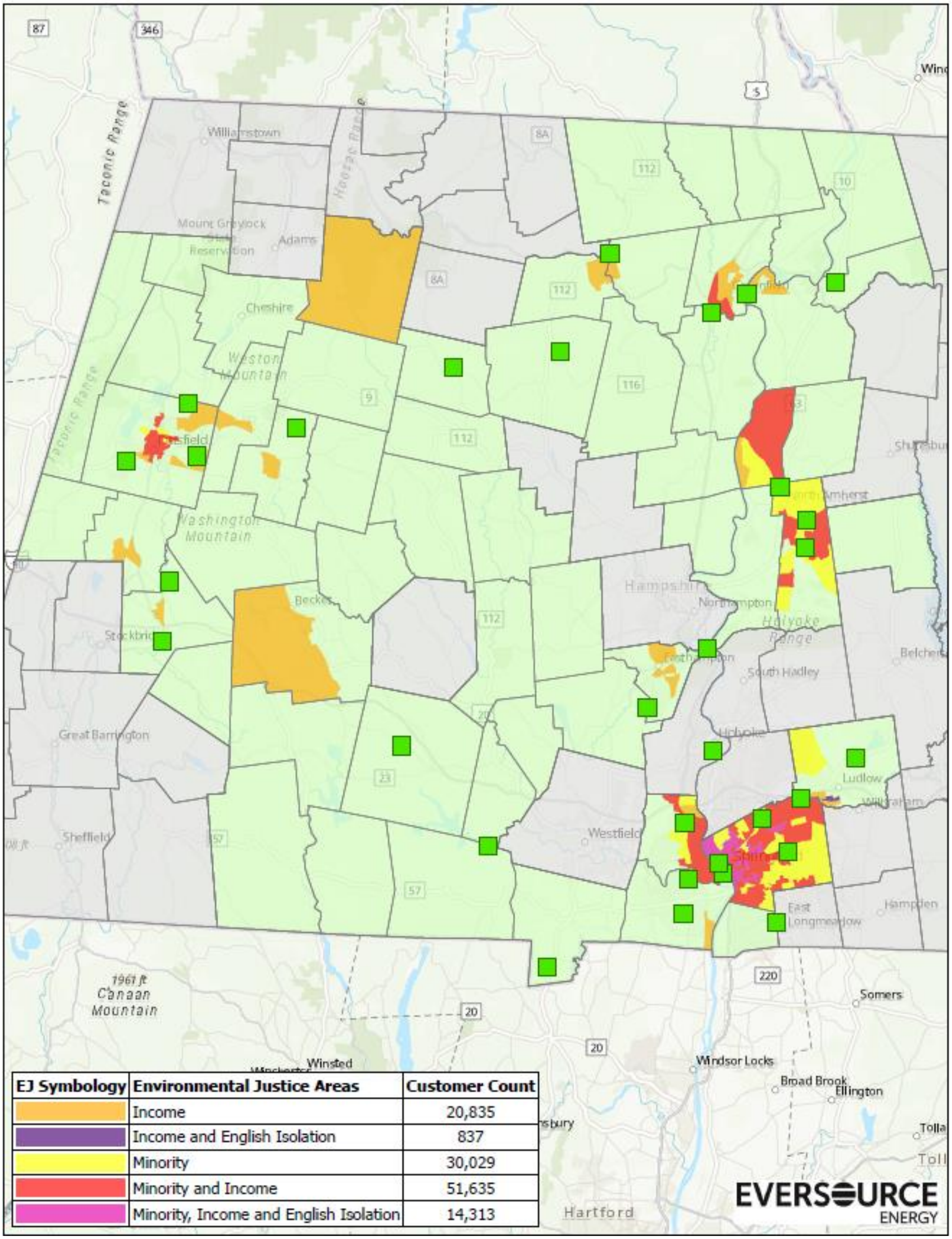


Figure 57: WMA Sub-Region Showing Substation and EJ Community Locations

4.6.2. Customer Demographics

Understanding the customer demographics of a region is essential to understanding not only how regions are expected to develop in the future as the system electrifies, but also to understanding how the customer base in the regions has historically been developing.

4.6.2.1 Customer Count

The Eversource WMA Sub-Region consists of 212,328 customer accounts, with an approximate breakout by zip code as shown in Figure 58 below.

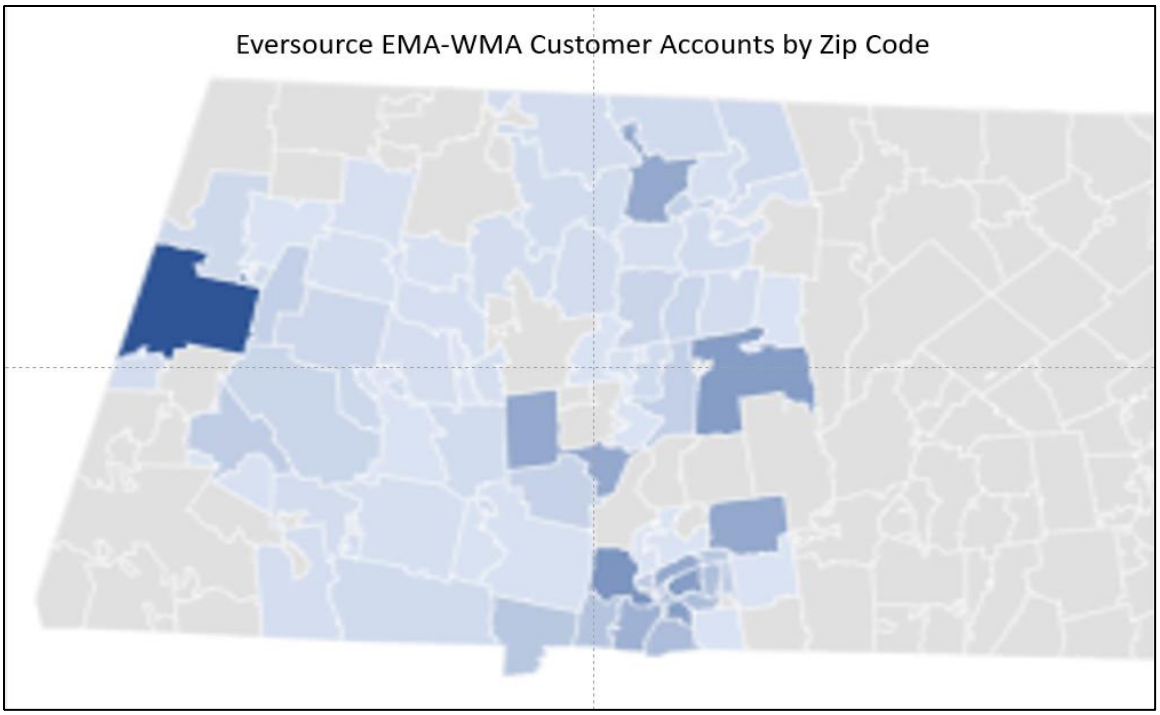


Figure 58: WMA Sub-region Eversource Accounts by Zip

The color in the figure has been adjusted to that the zip code with the largest numbers of accounts is darker and the zip code with the least numbers of account is a lighter shade of blue, with the darkest color being the zip code with the most customer accounts. It must be noted that in some cases, some customers will have more than account depending on their electric consumption.

4.6.2.2 Environmental Justice Communities

Figure 57 (in Section 4.6.1, Maps) shows an overlay of the EJ population in the WMA region derived from the Environmental Justice[85] (EJ) Map Viewer.[86] The EJ Map Viewer is an interactive map that displays the 2020 EJ block groups based upon demographic criteria developed by the state's Executive Office of Energy and Environmental Affairs (EEA). As shown, all MA 2020 Environmental Justice Block Groups, especially Income (brown), Minority (yellow), Minority and Income (red), and Minority, Income and English Isolation (magenta) are represented in this sub-region. The number of customers in each EJ block is shown in the legend. Eversource bulk distribution substations (green squares) are geographically dispersed across the sub-region, in both EJ and non-EJ communities, based primarily on load density.

4.6.2.3 Electrification Customer Classification

In order to better understand how regional adoption of electrification will play out, the Company has reviewed its customer data and identified socioeconomic variables relating to a customer's propensity to adopt heat pumps and electric vehicles. With specific variables driving electrification more than others, variables were ranked in order of importance and then a total score was calculated for each customer by summing their variable rankings. This allowed the Company to assign a priority score to each customer, which was then used to segment the customers into adoption clusters which represented their propensity to adopt both heat pumps and electric vehicles. A detailed accounting of the respective variables and their impact on the adoption propensity modeled by the Company can be found in Section 8.2.2 and Section 8.3.2.

For heat pumps, Eversource segmented the customer into 6 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, Cluster V, and Cluster VI. For electric vehicles, Eversource segmented the customers into 5 clusters in order of adoption propensity: Cluster I, Cluster II, Cluster III, Cluster IV, and Cluster V. Respectively in order of their likelihood to adopt the technologies. Figure 59 shows the customer make up by cluster type for the sub-region. From the figure Eversource can determine 17% of customers have the highest propensity in Cluster I to adopt heat pumps (with 46% in Clusters I and II), while only 3% have the highest propensity in Cluster I to adopt electric vehicles (with 25% in Clusters I and II). Additionally, only 4% of customers fall into Cluster VI, the lowest adoption propensity for heat pumps (with 14% in Clusters V and VI) and 16% fall into the lowest adoption propensity, Cluster V, for electric vehicles (with 52% in Clusters IV and V).

[85] See Footnote 19 in Section 4.3.2.2
[86] See Footnote 20 in Section 4.3.2.2

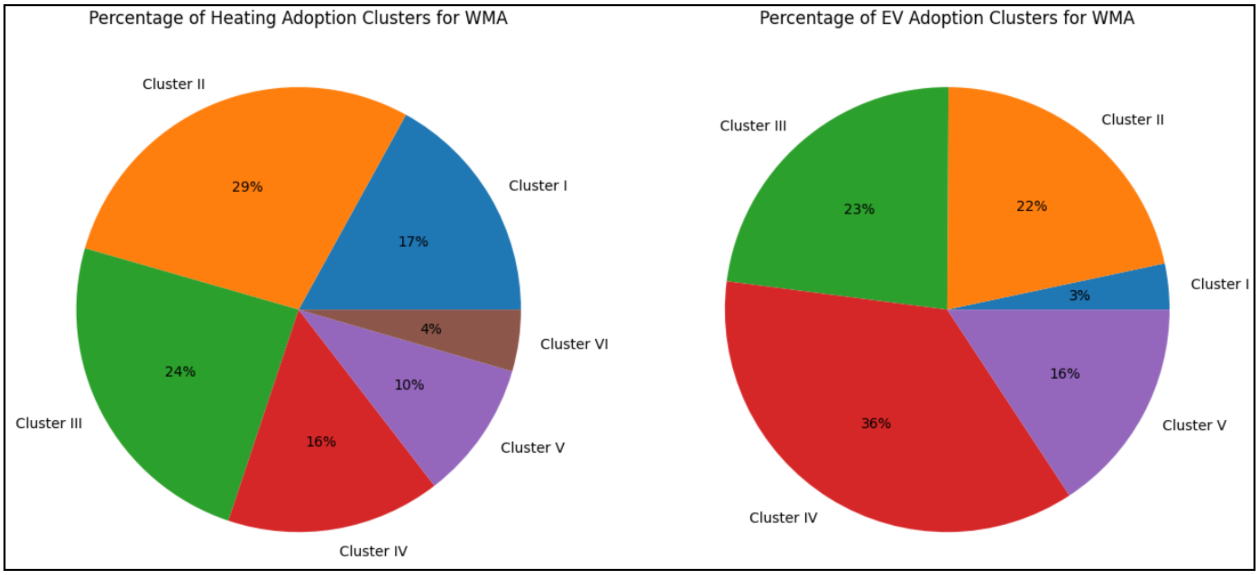


Figure 59: Cluster Percentages for a) Heating Adoption and b) Electric Vehicle Adoption

4.6.3. Economic Development

The Western Massachusetts Gross Metropolitan Product (GMP) [87] as shown in Table 23 below has averaged over one percent growth over the last ten years and has recovered remarkably after a five percent decline due to the pandemic in 2020. Real Household Income has maintained just over one percent growth over the last ten years. Income decreased in 2022 as the effects of stimulus packages diminished; however, income has begun to increase again and remains elevated above pre-pandemic levels. After a sizable 10.4% hit due to the pandemic, Total Employment has fully rebounded to pre-pandemic levels and maintains an average 0.5% growth over the last ten years, with an average of over 3% growth in the last three years. The Unemployment Rate has continued to drop, at an average rate of 5.7%, over the last ten years, despite nearly tripling in 2020. Housing Starts continue to be variable but have maintained 1.9% average growth in the last ten years.

[87] The market value of all goods and services produced in the region. GMP is the regional equivalent of the Gross Domestic Product (GDP), which measures the nation's economy

Table 23: WMA Sub-Region Historic Economic Development

Western MA Economic Statistics*										
	Gross Metro Product		Real Household Income		Total Employment		Unemployment Rate		Housing Starts	
2014	37		109,553		334		6.8		626	
2015	38	2.4%	112,808	2.9%	339	1.4%	5.7	-18.9%	674	7.0%
2016	38	0.0%	113,818	0.9%	344	1.5%	4.9	-17.1%	812	17.0%
2017	38	0.7%	115,697	1.6%	347	0.7%	4.7	-5.0%	748	-8.6%
2018	39	1.9%	117,439	1.5%	348	0.4%	4.3	-8.3%	928	19.4%
2019	40	1.6%	119,539	1.8%	351	1.0%	3.8	-13.0%	870	-6.6%
2020	38	-5.0%	126,845	5.8%	318	-10.4%	10.0	61.8%	843	-3.3%
2021	40	5.5%	127,979	0.9%	333	4.3%	6.5	-54.8%	844	0.2%
2022	40	1.4%	118,534	-8.0%	345	3.7%	4.5	-44.7%	772	-9.4%
2023	41	2.0%	122,445	3.2%	351	1.7%	3.8	-17.4%	756	-2.2%
CAGR '14-'23		**1.1%**		**1.1%**		**0.5%**		**-5.7%**		**1.9%**
**Source: Moody's Analytics data for Pittsfield, MA and Springfield, MA*										

4.6.4. Electrification Growth

Electrification of key energy sectors, mobility and heating, has already been taking place over the past decade, albeit at a relatively slow pace. Currently, there is no mandatory reporting of electrification efforts unless customers utilize programs through Mass Save or tap into other funding sources. Therefore, existing electrification numbers are likely undercounting actuals.

4.6.4.1 Heating Electrification

Over the 2019-2023 period, 2,471 homes in the WMA Sub-Region received incentives from Eversource via the Mass Save programs for the installation of heat pumps to replace fossil fuel heating systems. Of these, 2,134 were in homes replacing oil or propane heat, and 337 in homes replacing gas heat. Eversource notes that under the current Mass Save framework, electrification incentives for customer replacing pipeline gas heating systems are provided by their gas LDC; as a result, Eversource electric does not currently have insight into how many heat pumps were installed at homes that have non-Eversource gas service. Additionally, there may be some heat pump installations that occurred without pursuing a Mass Save incentive, though this number is likely to be small given the generous nature of the incentives.

4.6.4.2 Electric Vehicles

Table 24 shows the current EV count of all Light Duty Vehicles by city in this sub-region. The data highlights the fact that EV deployment in this sub-region is still in the nascent stage, accounting for only 1% of all vehicles in the region. The total of just over 4,800 EV represents less than a quarter of the Commonwealth's 2050 goal for the region.

Table 24: Current EV Count by City in WMA

WMA- Municipality	EV Count (1/1/2023)	EV Count as a % of All Vehicles	2025 All Options Goal
Agawam, Massachusetts	132	1%	4.3%
Amherst, Massachusetts	536	4%	
Ashfield, Massachusetts	34	2%	
Becket, Massachusetts	25	1%	
Bernardston, Massachusetts	16	1%	
Blandford, Massachusetts	13	1%	
Buckland, Massachusetts	16	1%	
Cheshire, Massachusetts	13	1%	
Chester, Massachusetts	4	1%	
Chesterfield, Massachusetts	13	1%	
Chicopee, Massachusetts	147	1%	
Colrain, Massachusetts	16	1%	
Conway, Massachusetts	26	1%	
Cummington, Massachusetts	14	2%	
Dalton, Massachusetts	34	1%	
Deerfield, Massachusetts	97	2%	
East Longmeadow, Massachusetts	113	1%	
Easthampton, Massachusetts	193	1%	
Erving, Massachusetts	12	1%	
Gill, Massachusetts	19	1%	
Granville, Massachusetts	7	1%	
Greenfield, Massachusetts	150	1%	
Hadley, Massachusetts	220	1%	
Hancock, Massachusetts	8	1%	
Hatfield, Massachusetts	36	1%	
Hinsdale, Massachusetts	15	1%	
Huntington, Massachusetts	11	1%	
Lanesborough, Massachusetts	23	1%	
Lee, Massachusetts	42	1%	
Lenox, Massachusetts	74	2%	
Leverett, Massachusetts	84	5%	
Leyden, Massachusetts	9	1%	
Longmeadow, Massachusetts	254	2%	
Ludlow, Massachusetts	63	1%	
Middlefield, Massachusetts	3	1%	
Montague, Massachusetts	86	1%	
Montgomery, Massachusetts	9	1%	
New Ashford, Massachusetts	4	2%	
Northampton, Massachusetts	685	3%	
Northfield, Massachusetts	32	1%	
Otis, Massachusetts	19	1%	
Pelham, Massachusetts	61	5%	

WMA- Municipality	EV Count (1/1/2023)	EV Count as a % of All Vehicles	2025 All Options Goal
Peru, Massachusetts	7	1%	
Pittsfield, Massachusetts	180	1%	
Plainfield, Massachusetts	8	1%	
Richmond, Massachusetts	39	3%	
Russell, Massachusetts	6	1%	
Sandisfield, Massachusetts	12	1%	
Savoy, Massachusetts	6	1%	
Shelburne, Massachusetts	37	2%	
Shutesbury, Massachusetts	71	4%	
Southampton, Massachusetts	54	1%	
Southwick, Massachusetts	55	1%	
Springfield, Massachusetts	258	1%	
Sunderland, Massachusetts	40	1%	
Tolland, Massachusetts	5	1%	
Tyringham, Massachusetts	15	4%	
Washington, Massachusetts	2	1%	
West Springfield, Massachusetts	132	1%	
Westfield, Massachusetts	179	1%	
Westhampton, Massachusetts	30	2%	
Whately, Massachusetts	25	1%	
Wilbraham, Massachusetts	149	1%	
Windsor, Massachusetts	8	1%	
Worthington, Massachusetts	19	2%	
Total	**4,802**	**1%**	

4.6.5. DER Adoption (Battery Storage and PV Solar)

Similar to the EMA-South area, the Eversource WMA area has a significant DER penetration for solar and solar coupled with battery storage due to the larger proportion of open space in this part of the Company’s service territory, and due to the nature of incentives that are available. The categories of DER interconnecting in the WMA area include behind-the-meter (BTM) battery storage, Combined Heat and Power (CHP) cogeneration, fuel cells, fuel cells coupled with battery storage, gas turbine generators, hydro, internal combustion (diesel) engines, microturbines, standalone and BTM solar, solar coupled with battery storage (both AC and DC coupled), steam turbine, and wind turbines.

As shown in Figure 60 below, the largest share of existing online DER interconnections is solar (both standalone and BTM), with and without battery storage. The current online solar total in the WMA area is at least 384.2 MW of solar only and another 9.3 MW of solar coupled with battery storage. The total DER including other technologies is approximately 569 MW.[88]

The WMA area has a significant number of projects with recently completed impact studies but not yet interconnected, projects participating in Group Studies, projects in queue, projects in the application stage, and projects in a prescreen stage without a format application submitted yet. These applications include: 128 MW of standalone BESS, 239.4 MW of standalone Solar, 30.2 MW of standalone solar coupled with BESS. The total DER in queue or in study process is 428.6 MW. The amount of DER deployment currently far exceeds native load growth and has become the predominant driver for substation and distribution capacity expansion needs. Based on local irradiance at historical times of peak, this aggregate (both installed and in-queue) Solar and Battery Storage build out translates to 74 MW of contribution toward North Metro Boston peak demand reduction or 8% of 2034 peak demand.

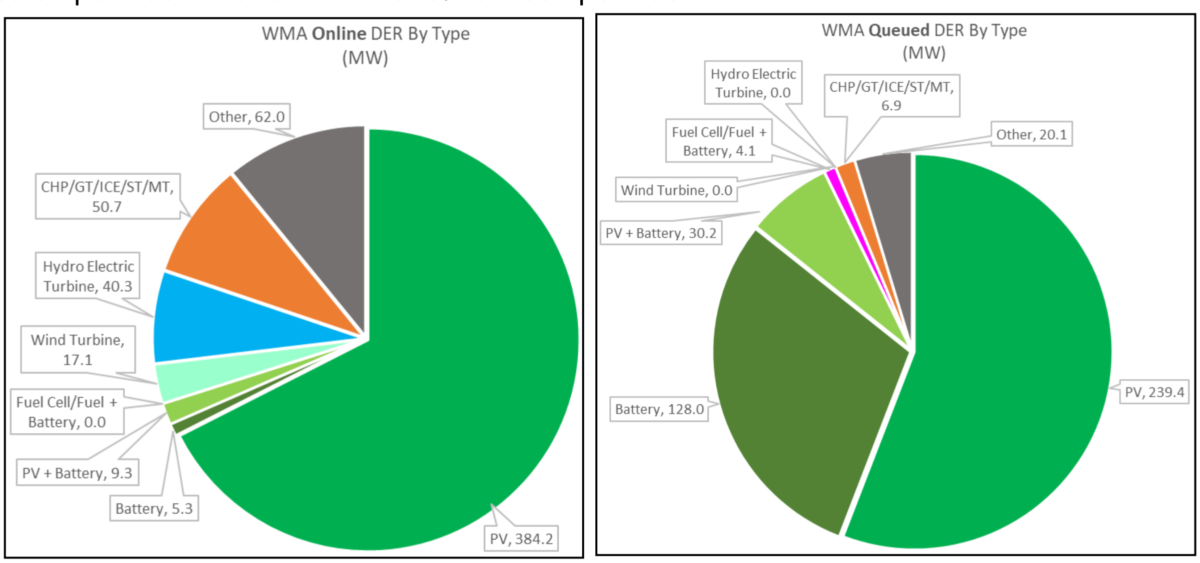


Figure 60: WMA Online DER and Queued DER by Technology (MW by Type)[89]

Figure 61 below describes the growth of DERs in the WMA West area since 2010. As seen from the graph, the annual DER interconnections in the area show a significant growth trend in the past five years.

[88] Per latest tracking system extraction

[89] The CHP/GT/ICE/ST/MT category includes combined heat and power (CHP), gas turbine (GT), internal combustion engine (ICE), steam turbine (ST) and microturbine (MT) applications.

EVERSOURCE

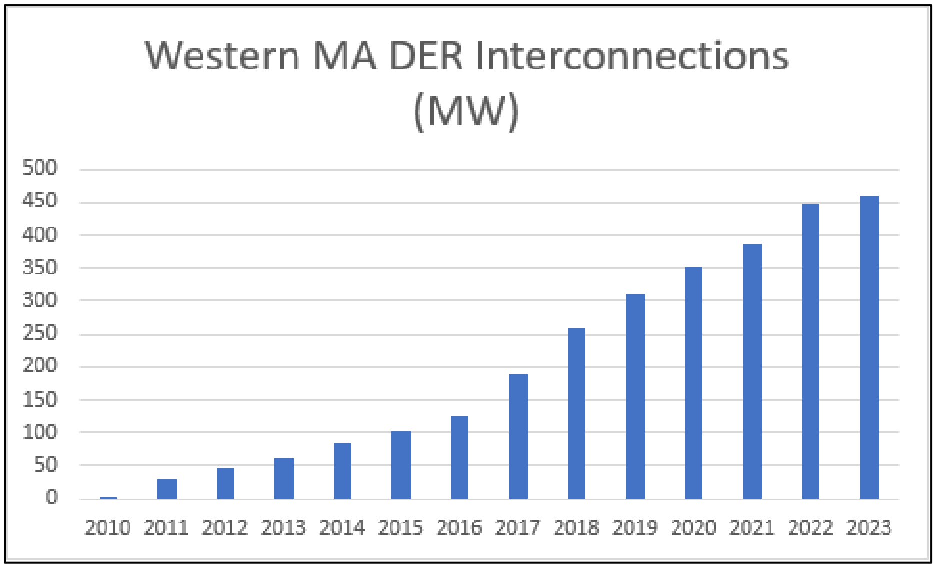


Figure 61: WMA Annual DER Interconnections

As discussed earlier in Section 4.5.5, Eversource performed a total of seven Group Studies (six in SEMA and one on WMA) under the 20-75-B Provisional DER Program Order. The Company performed a Group Study for the Plainfield-Blandford area in WMA and filed a Capital Investment Project (CIP) proposal for the group study solutions that met the eligibility requirements for the Provisional Program. The proposal, along with five other proposals for the EMA-South region, were then adjudicated by the Department under separate dockets; the Plainfield-Blandford docket was DPU 22-52. As of this time, DPU 22-22 has not been approved by the Department (only DPU 22-47 has been approved so far), but a decision on the other CIPs expected in the third quarter of 2023.

Assuming the Department approves the Plainfield-Blandford CIP docket, the Company must upgrade the two existing transformers at the Blandford 19J distribution bulk substation with two new 62.5 MVA transformers with associated bus-work, switchgear and distribution system upgrades, within four years of receipt of the approval order, as stipulated in the Provisional Program Order.

Following successful completion of the Group Studies, the Company has standardized on Group Studies as an approach to expedite interconnection studies in all Planning Regions. The Company's foundational assumption is that Cost Allocation methodologies such as those proposed under 20-75-B and approved under 22-47 will be applicable to Group Study solutions going forward to avoid some of the known disadvantages of the cause causation principle, including queue stagnation and free rider issues, especially at saturated substations.

4.6.6. Grid services

4.6.6.1 Demand Response

In 2022, the Company achieved 16.68 MW of savings from Active Demand Response, delivered through the Mass Save Programs, in the WMA Sub-Region.

4.6.6.2 Smart Inverter Controls

Please see Section 5.3.6.2.

4.6.6.3 Time-varying Rates

The Eversource WMA region is subject to rates that originated under the legacy Western Massachusetts Electric Company, so pricing is distinct from the Greater Boston, Cambridge, and South service areas. TOU rates are available for large general service customers. These customers fall under the Rate G-3 and Rate T-5 customer classes. Rate G-3 customers are greater than 349 Kw. Rate T-5 customers are greater than 2,499 KW.

TOU rates are on the delivery side only, but both demand and energy prices are time differentiated. Demand is assessed to the highest metered demand during peak hours. Base distribution energy prices have a higher rate during peak hours and a lower rate during off-peak hours. Peak period in the West is defined as 12 noon to 8 pm weekdays eastern standard time with all other hours deemed off peak.

4.6.6.4 Energy Efficiency

In 2022, the Company achieved 5.2 MW of passive peak demand savings in the West region through its delivery of the Mass Save efficiency programs.

4.6.7. Capacity Deficiency

The Company's planning process, including development of solutions for capacity and reliability needs, is discussed in detail in Section 4.1.

In low to medium load density areas, such as the WMA Sub-Region, a higher degree of reliability is ensured by maintaining sufficient capacity such that the system can be operated without the permanent loss of power to customers following the loss of a transformer at a substation – also known as N-1 Contingency Design.[90]

Through its annual capacity planning processes, as summarized in Section 4.1, and reported in the ARR under DPU docket 23-ARR-02[91] and as reported in the Company's Rate Case Filing under DPU 22-22,[92] the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing capacity[93] and/or reliability[94] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations that have capacity or reliability deficiencies now. Table 25 below, list the community in WMA and the existing substations supply deficiency by type (Reliability and/or Capacity) in the fourth column.

Table 25: WMA Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Ashfield	Town	Franklin	Capacity	Now/Existing
Chesterfield	Town	Hampshire	Capacity	Now/Existing
Cummington	Town	Hampshire	Capacity	Now/Existing
Longmeadow	Town	Hampden	Capacity	Now/Existing
Middlefield	Town	Hampshire	Capacity	Now/Existing
Plainfield	Town	Hampshire	Capacity	Now/Existing
Springfield	City	Hampden	Capacity	Now/Existing
Windsor	Town	Berkshire	Capacity	Now/Existing
Worthington	Town	Hampshire	Capacity	Now/Existing
Ludlow	Town	Hampden	Reliability	Now/Existing
Dalton	Town	Berkshire	Reliability	Now/Existing
Lanesborough	Town	Berkshire	Reliability	Now/Existing
New Ashford	Town	Berkshire	Reliability	Now/Existing

[90] See Footnote 41 in Section 4.3.7
[91] See Footnote 42 in Section 4.3.7
[92] See Footnote 43 in Section 4.3.7
[93] See Footnote 44 in Section 4.3.7
[94] See Footnote 45 in Section 4.3.7

Table 26 below shows the substation name or location in the first column, followed by the Community that is supplied by the substation. The table also shows how loaded the substation is projected to be compared to the substation capacity.[95] Values greater than 100% in the last columns of the table is a violation of the company criteria since the transformers expected peak load will exceed the substation capacity. For Partridge and Ludlow substations the % of Substation Capacity value in the third column of the table denotes both substation above reliability requirements instead of capacity. The impact of substation and distribution assets being "at capacity" has multiple facets. Eversource may have to employ measures like temporary load transfers to other substations, may have to install enhanced cooling on substation transformers or other equipment, may have to deploy temporary generation in response to a substation or on a distribution feeder for load relief in response to equipment outages, and the Company may be unable to interconnect large new customers short term until the "capacity deficiency" is addressed.

Table 26: WMA Substations with Projected Capacity Deficiency and Communities Impacted

Substation Name or Location	Community Supplied	2023 % of Substation Capacity
Plainfield	Ashfield, Chesterfield, Cummington, Middlefield, Plainfield, Windsor, and Worthington	**111%**
Clinton	Springfield	**103%**
Franconia	Springfield and Longmeadow	**93%**
Partridge[96]	Dalton, Lanesborough, and New Ashford	**100%**
Ludlow[97]	Ludlow	**100%**

Currently 5 out of 28 substations supplying WMA sub-region have capacity and/or reliability violations. Through its annual capacity planning processes, as noted in the ARR, the company goal is to have a solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon or exciding reliability violations that result in customer outages during N-1. The following paragraphs describe the need and Company's plan for the substations currently at capacity (Plainfield, Clinton, Franconia, Partridge, and Ludlow).

[95] Refer to Footnote 47 in Section 4.3.7

[96] 100% Substation Capacity reflects substation reliability violation not capacity violation.

[97] 100% Substation Capacity reflects substation reliability violation not capacity violation.

4.6.7.1 Capacity Deficiencies due to Load Growth and Reliability

- **Clinton substation upgrade -** The Company has internally approved, on-going, projects to replace one transformer and switchgears in the next 5 years. Clinton Substation is a three 115/13.8 kV transformers substation serving the City of Springfield with several critical customers such as three hospitals and other large commercial centers. Large customer load additions in the area requires station upgrades to increase the station capacity and improve the service reliability. The 2023 projected peak load is 103% of substation capacity which is only bound to get worst with new customer load additions. The on-going substation upgrades will address long-term capacity and reliability concerns in the area.
- **Plainfield transformer upgrade** - Plainfield Substation is a single ended (1 transformer) 115/23kV substation serving the above towns and that also provides backup capability to nearby single transformer substations supplying nearby towns. The 2023 projected peak load is 111% of substation capacity. The Company has an internally approved project to replace the existing 5MVA transformers with a standard size 37/50/62.5MVA transformers with an expected in-service date of 2026. The transformer upgrade will address long-term capacity and reliability concerns in Plainfield Substation and nearby areas. Currently, substations capacity concerns are being addressed by emergency operational measures, including mobile equipment.
- **Franconia Substation Upgrade –** The Company is in the planning phase for a proposed long-term solution to address capacity concerns at the Franconia Substations. Currently, substations capacity concerns are being addressed by emergency operational measures, including mobile equipment. The long-term solution is covered in Section 6.8.1.
- **Partridge and Ludlow Substation –** The company is in the planning stages for a proposed solution to address reliability concerns at the Partridge and Ludlow Substation. As per the company planning standards substation shall be designed to sustain any single contingency with no loss of load. Partridge and Ludlow are a single transformer substation which would rely on Distribution Transfer switching during single contingency condition. Because of distribution system limitations, both substations do not have sufficient transfer capability to restore all customers following the loss of the substation transformer. Currently, substations capacity concerns are being addressed by emergency operational measures, including mobile equipment. The long-term solutions for both substations are covered in Section 6.8.1.

4.6.7.2 Capacity Deficiencies due to DER Penetration

- **DPU 22-52 (Blandford-Plainfield)**[98] – The Plainfield-Blandford Group comprises of one substation in Western Massachusetts (WMA): Blandford 19J Substation. This substation is currently supplied by two 115/23 kV transformers sized at 30MVA and 25MVA. The Blandford substation serves 11 MVA of customer peak load. There is a total of 37 MW of installed ground mounted (large) DER, in addition to less than 1 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 13 MW of large DER, bringing the total DER penetration to 454% of peak load for the group. Figure 62 below shows the approximate geographical location of the group of stations, and the geographic location served by the substations, in the WMA Service Area. The CIP solution is described in Section 6.

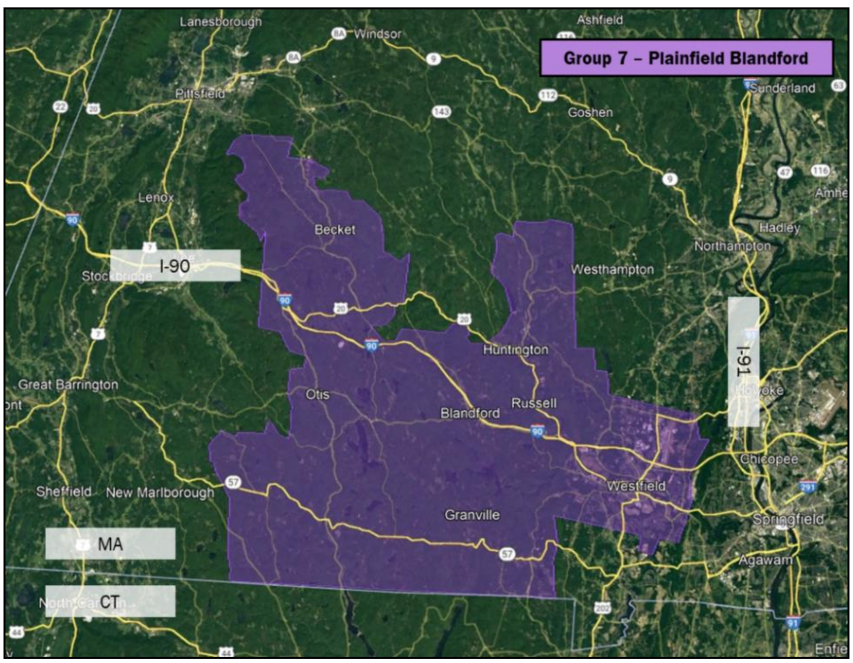


Figure 62: Plainfield-Blandford DER Group Approximate Boundary

---

98 Refer to DPU 22-51 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023

EVERSOURCE

4.6.8. Aging Infrastructure

4.6.8.1 Substation Transformers

There are 72 distribution substation transformers in WMA. The following chart shows the age of the distribution substation transformers. 25 distribution substation transformers or 35% of the population with age records are less than 45 years of age. 22 distribution substation transformers or 31% of the WMA distribution station transformer population are older than 60 years.

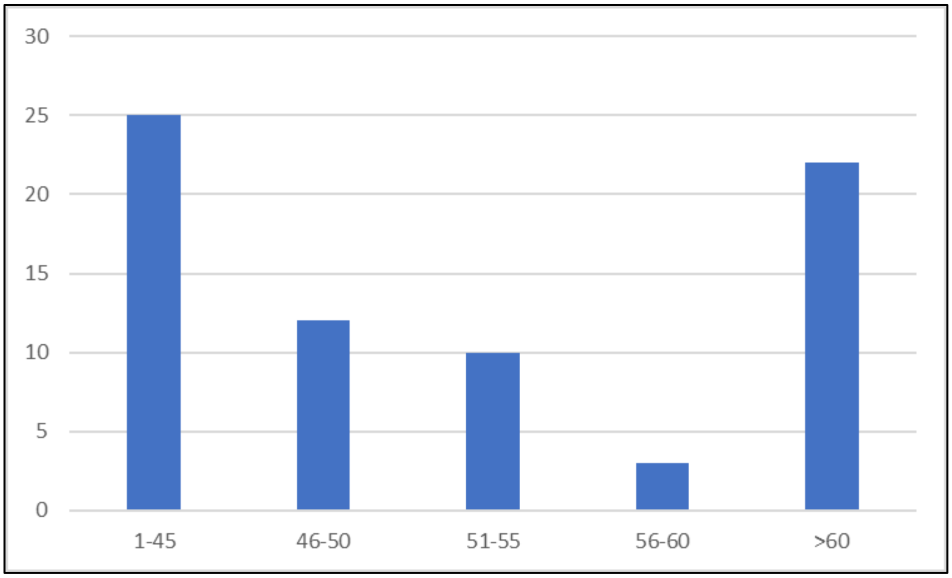


Figure 63: Age of Distribution Transformers in WMA

4.6.8.2 Breakers

There are 335 breakers currently in WMA. The following chart shows the age of 308 breakers. 75 breakers or 24% of the WMA breaker population with age records are at or over 50 years of age. 91 breakers or 30% of the WMA breakers with age records are at or under ten years of age.

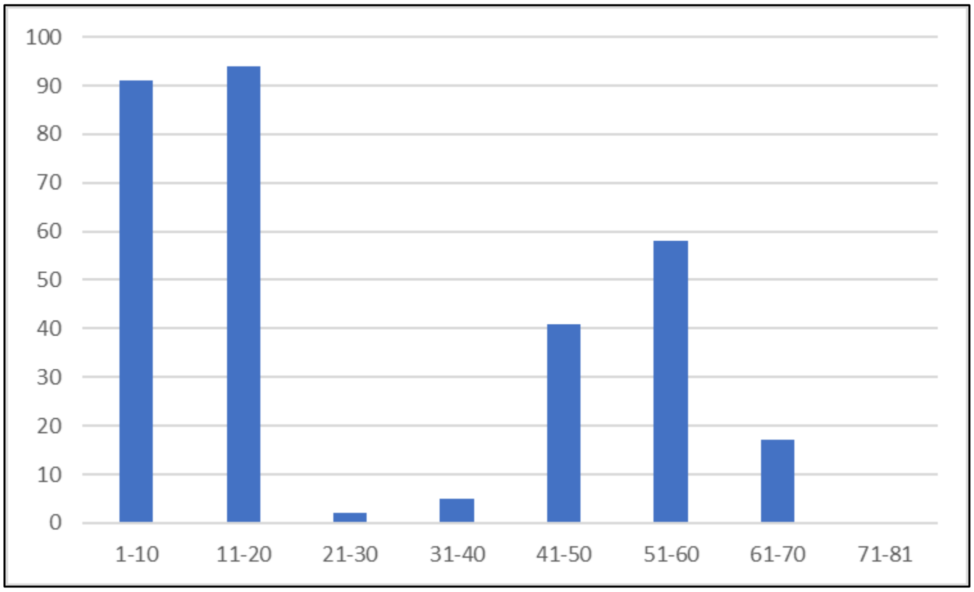


Figure 64: Age of Breakers in WMA

4.6.8.3 Reclosers

There are 50 reclosers currently in service in WMA. The following chart shows the age of 34 WMA reclosers. 28 reclosers or 82% of the reclosers with age records are at or under ten years of age.

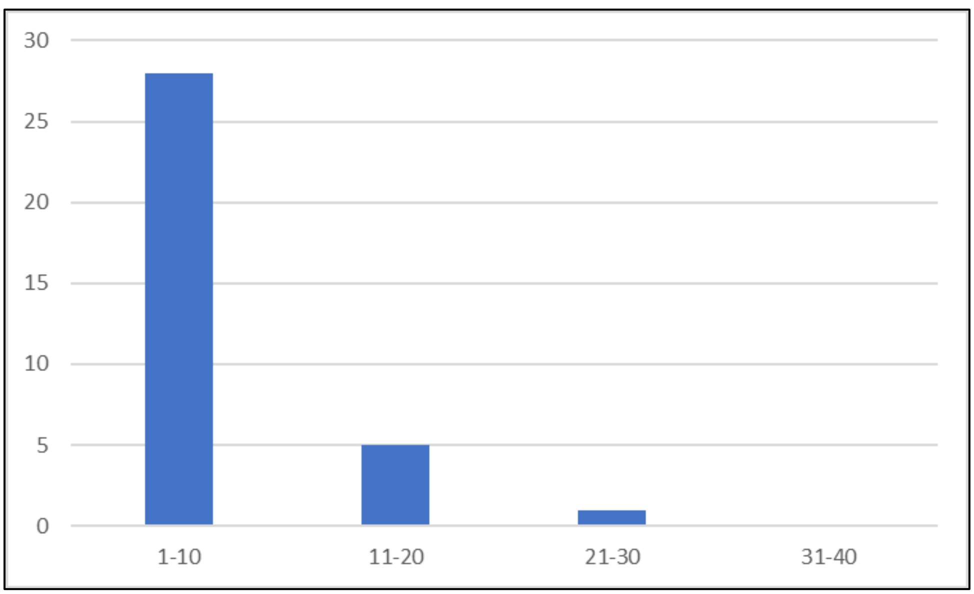


Figure 65: Age of Reclosers in WMA

4.6.8.4 Poles

The process of calculating an effective age for poles is currently still in progress in WMA.

4.6.9. Reliability and Resilience

Section 4.1.9 above includes definitions of commonly used reliability metrics and definitions of blue-sky and all-in performance measures.

4.6.9.1 Blue-sky Reliability Performance

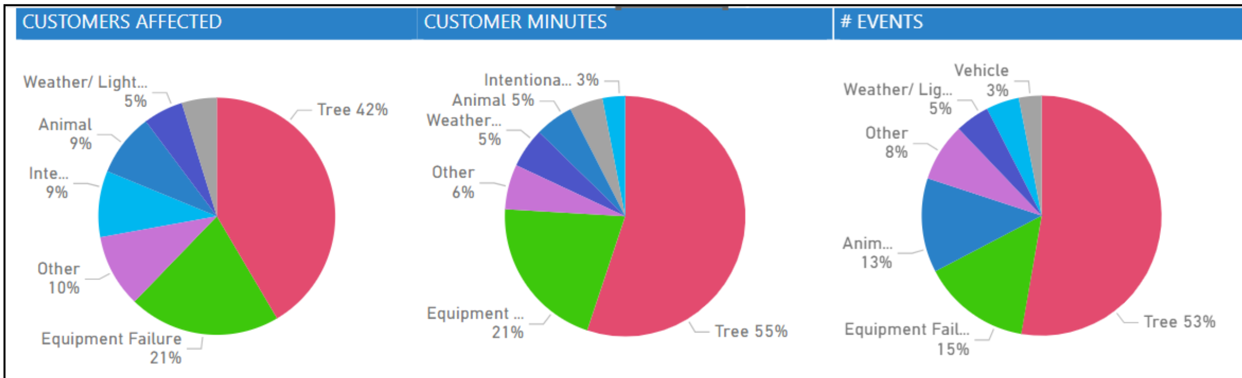
The increase of blue-sky SAIDI, SAIFI and CAIDI in WMA from 2020 to 2021 was followed by a decline in 2022, resulting in 2022 values slightly higher than 2020 values. Compared to the utilities participating in the 2022 IEEE Benchmark Survey (shown earlier in Section 4.1.9, Table 1), the WMA SAIDI, SAIFI and CAIDI are all in the first quartile.

Table 27: WMA Blue-Sky reliability Performance

Metric	2020	2021	2022
SAIDI	58.6	96.0	66.4
SAIFI	0.69	0.83	0.73
CAIDI	84.7	115.7	91.3

The following graphs and tables show the reliability performance in WMA over the past three years (2020-2022). In WMA, a total of 48,606,988 Customer Minutes of Interruption (CMI) were experienced in 2020-2022. These results show the reliability performance, meaning the duration and frequency of outages during blue-sky days, i.e., excluding major exception days due to major storms.

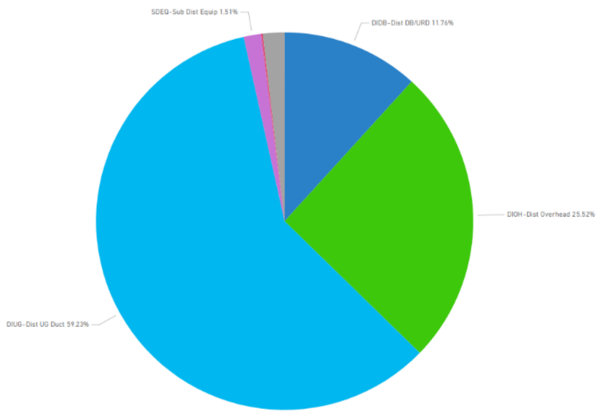
- The leading cause of outages in terms of event counts, CMI and customers impacted is tree-related outages. Specifically, tree-related outages make up 55% of the Customer Minutes of Interruption (CMI), 42% of the customers affected and 53% of the events.
- The second leading cause of outages in terms of customers affected is equipment-related outages. Specifically, equipment-related outages make up 21% of the Customer Minutes of Interruption (CMI), 21% of the customers affected and 15% of the events. This means that the interruptions related to equipment causes impact a larger number of customers, as compared to tree-caused interruptions.
- Animal and vehicle outages were also contributing significantly to outages in WMA from 2020 to 2022. Specifically, animal-related outages make up 5% of the Customer Minutes of Interruption (CMI), 9% of the customers affected and 13% of the events, while vehicle-related outages make up 4% of the Customer Minutes of Interruption (CMI), 4% of the customers affected and 3% of the events.
- 5% of the number of events, customers affected and CMI are attributed to weather/lightning. This still refers to weather-related interruptions on blue-sky days, meaning days that had minor storms only and were not classified as major exception days with major storms.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	42,577	2,506,251	60.52	1097
Equipment Failure	103,045	10,114,002	144.59	1260
Intentional Operation	44,949	1,480,428	42.24	385
Other	49,374	2,934,010	98.35	676
Tree	206,344	26,794,507	218.30	4551
Vehicle	23,815	2,181,122	156.53	265
Weather/ Lightning	27,077	2,596,668	135.62	397
Total	**497,181**	**48,606,988**	**165.34**	**8587**

Figure 66: Leading Causes of Blue-Sky Outrages in the WMA Sub-Region

The following table and chart show a further decomposition of the equipment-related outages in the WMA system from 2020 to 2022.



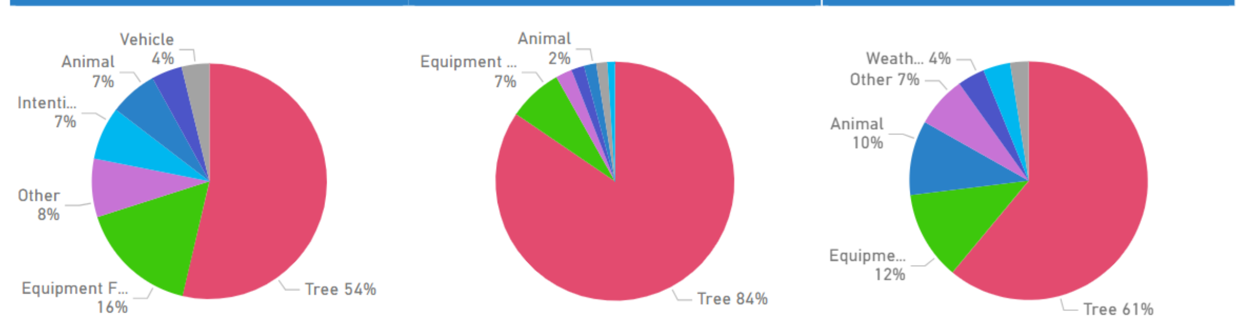
2023 Equipment Failure Types

EQUIPMENT_FAILURE	EVENTS	CUST_AFF	CMI
ASTR-Arrester	7	70	6,953
BUSH-Bushing	3	65	15,594
CARM-Crossarm	9	891	51,519
CBKR-S/S Breaker	7	9,770	295,695
CNTR-Connector/Clamp	39	2,760	85,109
CONS-Conductor Sec	212	1,455	149,876
COUT-Cutout	116	1,667	125,028
CPTR-Capacitor	1	259	15,540
DIDB CONP-Conductor Pri	179	7,499	964,803
DIOH CONP-Conductor Pri	132	21,062	1,452,694
DIUG CONP-Conductor Pri	186	39,283	5,250,847
ELBW-Elbow	7	945	115,858
INSL-Insulator	27	2,750	166,203
MTR-Metering	5	395	2,934
OTHR-Other	5	1,519	51,097
POLE-Pole/Structure	15	1,960	238,979
RECL-Recloser	2	416	16,156
REGL-Regulator	1	141	2,397
RELY-Relay - S/S	2	145	4,745
SPLC-Splice	2	90	19,814
SWCH-Switch/Discnt	2	3,799	129,673
TIES-Tie (Insul)	4	239	23,041
XFMR-Transformer	306	5,865	929,447
Total	**1260**	**103,045**	**10,114,002**

Figure 67: Breakdown of Equipment-Related Outages for WMA Sub-Region

4.6.9.2 All-In Performance

Variants of the above metrics can be used to quantify the resilience of the grid. Specifically, Eversource reports the all-in performance that includes major exception days. The all-in CMI from 2020-2022 is 153,382,819. This is more than 3 times larger than the aforementioned blue-sky CMI that is indicative of multiple severe storms present in the period reported. The following graph shows the breakdown to causes of customers impacted, CMI and number of events for the all-in performance. Tree-related interruptions remains the leading cause of all-in outages across all three metrics tracked and its impact is significantly increased in all-in numbers compared to blue-sky numbers as expected. This is discussed at length later in this report in terms of the worsening impacts of climate change on vegetation and vegetation-related outages.



Cause Group	Cust Aff	CMI	Avg Duration	# Events
Animal	42,808	2,556,575	64.94	1110
Equipment Failure	106,899	11,274,194	166.30	1320
Intentional Operation	47,492	1,557,530	41.60	405
Other	52,240	3,418,007	168.17	762
Tree	349,678	129,602,476	561.90	6705
Vehicle	24,842	2,317,231	164.08	275
Weather/ Lightning	27,533	2,656,806	142.10	407
Total	**651,492**	**153,382,819**	**391.97**	**10934**

Figure 68: Leading Causes of All-In Outrages in the WMA Sub-Region

4.6.10. Siting and Permitting

The WMA Sub Region is positioned to support the Commonwealth 's clean energy goals by providing and hosting substantial construction of solar. DER deployment far exceeds native load growth and has become the predominant driver for substation and distribution capacity expansion which will address load growth and reliability issues. The existing transmission infrastructure does not have sufficient capacity to absorb the influx of clean energy resulting in similar siting and permitting challenges to the Commonwealth as a whole, as outlined in Section 5.3.10.

Project Status

- **DER Group 5 - Plainfield-Blandford D.P.U. 22-52** - Group 5 consists of expansion of a substation in Blandford. The capital investment proposal for Group 5 was filed with DPU on 4/29/22 at the same time as Groups 2, 3 and 4. Reply briefs were submitted on 3/23/23. A decision has not been issued. The project may require a Chapter 40A filing with DPU. Upon approval and subsequent design and engineering, a petition will be submitted to DPU.

4.7. Technology Platforms That Eversource Has in Place Today

Eversource approach to technology platforms is linked to the achievement of the three grid-modernization objectives identified by the Department, which are to: (1) optimize system performance (by attaining optimal levels of grid visibility, command and control, and self-healing); (2) optimize system demand (by facilitating consumer price-responsiveness); and (3) interconnect and integrate DER. Technology investments that improve reliability and resiliency; optimize demand; increase system efficiency; and integrate distributed energy resources provides benefits to customers across the Eversource system.

The Company is utilizing advances in technology to build and operate a smarter, flexible, and resilient grid. The changing nature of the grid that historically was predictable with one-way power flow has become much more complex with increasing prevalence of DER resulting in two-way flows, load growth due to electrification, and climate change impacts that require new approaches. The new technologies the Company is investing in provide improvements in (1) visibility and situational awareness; (2) automated reconfiguration; (3) voltage management; (4) can get storm response; (5) asset management; and (6) new meter reading and data availability.

4.7.1. SCADA

The foundation of grid operations is remote visibility and control of field devices used to control power flows and restore customers. The system used for visibility and control is known as supervisory control and data acquisition (SCADA). The SCADA system includes multiple components. The software system used by control room operators for monitoring and control is known as the enterprise energy control system (eECS). Using the eECS, operators can view real time telemetry (e.g., current, voltage) from field devices and perform remote operations. The one-line views used by the foundation of grid operations is remote visibility and control of field devices used to control power flows and restore customers. The system used for visibility and control is known as supervisory control and data acquisition (SCADA). The SCADA system includes multiple components. The software system used by control room operators for monitoring and control is known as the enterprise energy control system (eECS). Using the eECS, operators can view real time telemetry (e.g., current, voltage) from field devices and perform remote operations. The one-line views used by operators in the eECS provide the electrical connectivity of the devices from the substation to the end of the feeder. The eECS is a single system for transmission and distribution. For a field device to be visible to operators in the eECS, it must have communications capability via fiber, radio or cellular. Substation devices, such as feeder breaker relays, typically transmit data to and from the eECS using fiber. The Company has over 4,550 substation devices in its eECS. Overhead and underground devices, such as reclosers or vacuum fault interrupting switches (VFI), typically communicate to the eECS via private radio or cellular communications. The Company has 3,229 overhead and 811 underground devices available in the eECS. Typically, substation and distribution line devices collect additional data not visible in the eECS that can be retrieved at the device itself. The database used to store historical SCADA data is the PI system.

4.7.2. Distributed Automation

Over the past 20 years, the Company has invested heavily in its distribution automation system as a critical component of its reliability engineering. Distribution automation is the term for the ability to remotely isolate a damaged portion of a distribution feeder and redirect power flows to restore unaffected sections of the grid. Once crews arrive at the location and repair the damage, the system is returned to its normal configuration. In designing distribution automation schemes, the Company targets limiting the number of customers in a protective zone to under 500. Currently, the average zone size is 277 customers. In many cases, distribution automation is designed to operate in under one minute. The Company uses multiple distribution automation technology configurations. In western MA, the Company uses recloser loop schemes with reclosers programed to operate automatically based on fault current sensing. In eastern MA, the Company uses a combination of operator switching based on SCADA indication and centralized automated scripts that identify and execute optimal switching steps needed to isolate and restore.

4.7.3. GIS

This section is covered in Asset Management, section 4.7.9.

4.7.4. Outage Management System (OMS)

This section is covered in Storm Response, section 4.7.8.

4.7.5. Outage Prediction Model (UConn)

The Outage Prediction Model (OPM) from the University of Connecticut ((UConn) is the most comprehensive outage prediction model for the electric distribution system currently available in the industry, suitable for predicting power outages associated with a host of weather events, including hurricanes, thunderstorms, rain/wind systems, and nor'easters.[99,100,101,102]

---

[99] Cerrai, D., Koukoula, M., Watson, P. and Anagnostou, E.N., 2020. Outage prediction models for snow and ice storms. Sustainable Energy, Grids and Networks, 21, p.100294.

[100] He, J., Wanik, D.W., Hartman, B.M., Anagnostou, E.N., Astitha, M. and Frediani, M.E., 2017. Nonparametric tree-based predictive modeling of storm outages on an electric distribution network. Risk Analysis, 37(3), pp.441-458.

[101] Wanik, D.W., Anagnostou, E.N., Hartman, B.M., Frediani, M.E.B. and Astitha, M., 2015. Storm outage modeling for an electric distribution network in Northeastern USA. Natural Hazards, 79, pp.1359-1384.

The model has been developed during the past decade in collaboration with researchers at the Eversource Energy Center, a research center located at the University of Connecticut. As shown in Figure 69, the UConn-OPM uses twenty years of historical analysis of environmental conditions, infrastructure, and damage data to train and tune different non-parametric regression tree models and predict outages for upcoming storms.

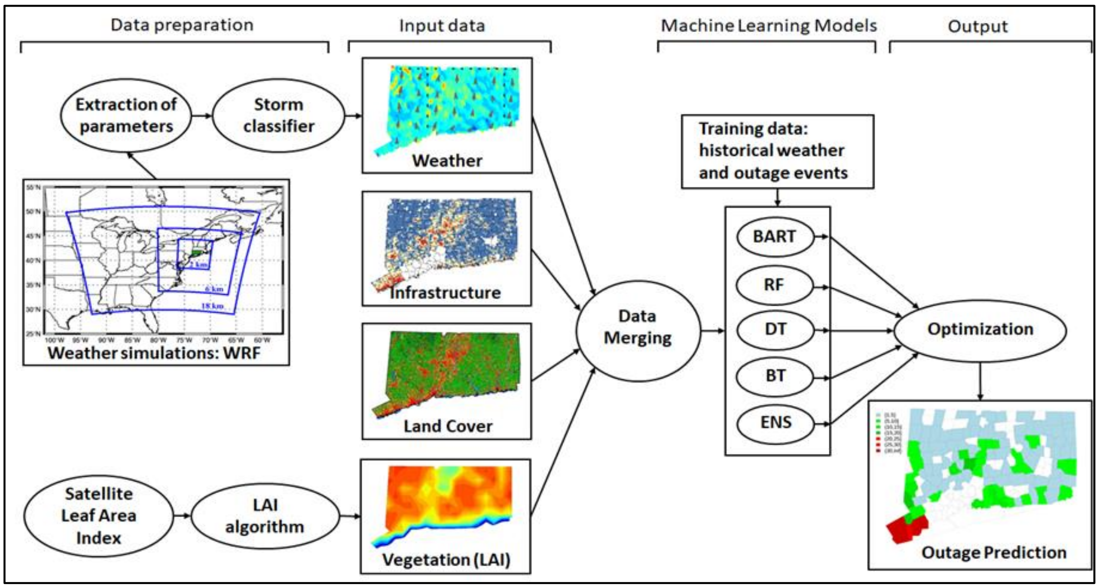


Figure 69: The UConn OPM architecture.[103]

The idea behind the OPM is to provide quantitative estimates of damage caused to the overhead electrical distribution network by severe weather to allow for knowledge-based storm preparedness decisions, for example crew counts and prestaging assignments and locations. To make accurate predictions, the OPM applies artificial intelligence to gain an understanding of the complex relationship among weather, land surface conditions, electric infrastructure, surrounding vegetation, and outages. Based on this understanding, the model predicts how many outages are expected in each part of the service territory and helps the Company respond quickly and intelligently to impacts from weather. The information allows the Company to position and prepare repair crews for the coming storm, as well as call in crews from other parts of the country before a single outage occurs.

---

[102] Wanik, D.W., Anagnostou, E.N., Astitha, M., Hartman, B.M., Lackmann, G.M., Yang, J., Cerrai, D., He, J. and Frediani, M.E.B., 2018. A case study on power outage impacts from future hurricane sandy scenarios. Journal of Applied Meteorology and Climatology, 57(1), pp.51-79

[103] Cerrai, D., Wanik, D.W., Bhuiyan, M.A.E., Zhang, X., Yang, J., Frediani, M.E. and Anagnostou, E.N., 2019. Predicting storm outages through new representations of weather and vegetation. IEEE Access, 7, pp.29639-29654

The OPM has become an essential decision support tool for Eversource Energy in its service territories covering Connecticut, Massachusetts, and New Hampshire. The success of OMP and the commerciality of OPM is exemplified by the fact that other utilities are interested in integrating OPM in their processes; OPM versions are being developed for the service territories of AVANGRID in the state of New York and Dominion Energy in Virginia and North Carolina. Within the next year, it will also be developed for Exelon in Pennsylvania, New Jersey, Maryland, Washington D.C., and Delaware. The constant feedback process and methodology updates of OPM have resulted in error values around 30% as of 2023.

4.7.6. Flooding Model (UConn)

The University of Connecticut Flash Flood Forecasting System integrates NOAA radar rainfall and NOAA tide and currents, as well as forecasted rainfall from NOAA-HRR and extratropical storm surge with a distributed hydrological model, the Coupled Routing and Excess STorage (CREST)[104,105] and a 2D hydrodynamic model, the Hydrological Engineering Centre – River Analysis System (HEC-RAS -HEC2D) (Figure 70 below). The hydrological and hydrodynamic models run at variable spatiotemporal resolution, (rainfall-runoff generation at 500 m-by-hourly, routing at 30 m-by-hourly, and floodplain dynamics at -currently- 1 m-by-hourly). The model has been developed during the past decade by researchers at the Eversource Energy Center, a research Centre located at the University of Connecticut. As shown in Figure 70, the UConn-Flash flood system uses the NOAA radar rainfall and current tide and currents to nowcast the current river discharge and water inundation (if any) that is used as a starting point for a 36-hour forecast of upcoming storms.

[104] Hardesty, S., Shen, X., Nikolopoulos, E., Anagnostou, E., 2018. A Numerical Framework for Evaluating Flood Inundation Hazard under Different Dam Operation Scenarios—A Case Study in Naugatuck River. Water 10, 1798. https://doi.org/10.3390/w10121798
[105] Shen, X., Anagnostou, E.N., 2017. A framework to improve hyper-resolution hydrological simulation in snow-affected regions. Journal of Hydrology 552, 1–12. https://doi.org/10.1016/j.jhydrol.2017.05.048

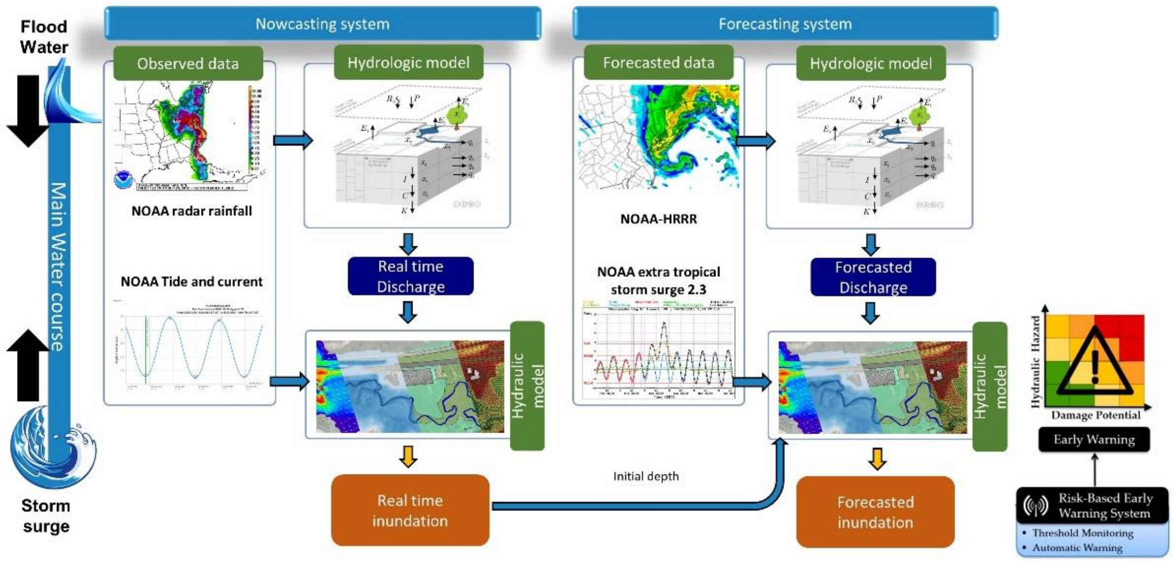


Figure 70: The UConn Flood System Architecture

In addition to floods from individual storm hazards (river flooding and coastal surge), the system can predict flooding from compound events. Common flood forecast systems typically focus on one flood driver at a time and ignore the potential compounding impacts of two or more hazards. The UConn Flash Flood Forecasting System outlines a unique compound flood hazard assessment framework that accounts for the interactions between coastal water level (surge and sea level rise), and fluvial flooding hazards caused by heavy precipitation. Warnings are emailed once the forecasted inundation depth reaches specific warning thresholds in vicinity of Eversource substations. The information allows Eversource to position and make substation preparations before a flood occurs.

The model's effectiveness was proven by testing over 1500 flood events spanning from 1979 to 2020[106], as well as historical hurricanes[107].

---

[106] Mitu, M.F., Sofia, G., Shen, X., Anagnostou, E.N., (conditionally accepted -2023) Assessing the Compound Flood Risk in Coastal Areas: Framework Formulation and Demonstration. Journal of Hydrology (conditionally accepted)
[107] Khanam, M., Sofia, G., Koukoula, M., Lazin, R., Nikolopoulos, E.I., Shen, X., Anagnostou, E.N., 2021. Impact of compound flood event on coastal critical infrastructures considering current and future climate. Natural Hazards and Earth System Sciences 21, 587–605. https://doi.org/10.5194/nhess-21-587-2021

4.7.7. Voltage Management

Voltage quality for the power distribution system is primarily managed through substation equipment. Predetermined voltage set points are dispatched to each substation LTC through either local programming or SCADA control. The voltage setpoints are set at a conservative level to account for voltage drop across the distribution system and ensure Eversource customers receive acceptable power quality levels. Along the distribution circuits, voltage management and proper voltage quality is achieved through distribution line devices. Distribution line devices, such as capacitors and distribution voltage regulators, are placed based off need, with locations identified by engineering studies. These line devices are generally controlled through local control or on one-way pager-based communication with no feedback on the current state of operation to system operators. While the company ensures voltage quality to its customers, there are many limitations to the current voltage management system that need to be changed to optimize the grid. SCADA operable devices, both substation equipment and distribution line devices, are pivotal for the operation of an optimized voltage management system. Data driven operation based off analysis of real-time data from devices will allow for elimination of assumptions and over conservative setpoints that will provide more accurate settings and a more efficient system. Voltage management systems will further coordinate operation between devices with dynamic control to adjust for ever changing system conditions.

4.7.8. Storm Response

The Company's Outage Management System (OMS) is a detailed network model of the distribution system. The utility's Geographic Information System (GIS) is the source of this network model. By combining the locations of outage calls from customers, a rules engine is used to predict the locations of outages. For instance, all calls in a particular area downstream of a fuse could be inferred to be caused by a single fuse or circuit breaker upstream of the calls. This reduces outage durations due to faster restoration based upon outage location predictions. Calls are received into the OMS from multiple different sources including phone calls to Eversource's call center representatives, interactive voice response (IVR), eversource.com, text message, mobile app, and the municipal hub. The OMS has a simple interface that assists operations in prioritizing outages based on the company's emergency response plan. The OMS is also used to manage Eversource's crew resources increasing efficiency and situational awareness. OMS data is used to provide customers detailed information regarding their outage on the eversource.com outage map along with phone, text, and email notifications.

When storm events occur, Eversource engages personnel to analyze the OMS information and document damage to the electrical system. This damage assessment information is communicated back to the command centers either by field personnel entering the information into mobile devices or calling in to dispatching personnel. This damage assessment data is important so that Eversource may effectively manage and deploy resources and provide situational reports to government agencies, community leaders, media, and customers.

OMS data is also used for outage analytics. Real time dashboards provide quick insights into the status of estimated time of restoration (ETR's), emergency responder requests, town critical facilities, blocked roads, damage assessment, and crew management among others. OMS data supports distribution system planning activities related to improving reliability by providing important outage statistics and the data needed for the calculation of the system reliability metrics such as SAIDI, CAIDI, and SAIFI. OMS data also supports the improvement of distribution reliability by providing historical data to find common causes, failures and damages. By understanding the most common modes of failure, improvement programs can be prioritized with those that provide the largest improvement on reliability.

4.7.9. Asset Management

Geographic Information System (GIS)

The GIS system is the as-built asset repository which is the primary source model of the distribution system. The asset and connectivity model serves as the source system for operational systems, including outage management and distribution management for real time operations, and system planning models. The distribution GIS models provides views of the field installed distribution assets as well the substation internal equipment to operate the distribution circuits.

Maximo

Maximo is the work and asset management software application in use for the distribution system. Work orders for construction, inspection and maintenance are created and managed in Maximo. The GIS system provides asset information and location to support the design, planning and execution of planned and emergent work.

Cascade

Cascade is the software application that serves as the asset repository and system of record for substation equipment. Maintenance and inspection records are stored in Cascade, which drives the condition-based maintenance programs for substation equipment. Cascade initiates inspection and maintenance triggers, based on the equipment type, to create Maximo work orders for the planning and execution of the work. All inspection forms and results are stored in Cascade.

4.7.10. Meter Reading

The Company currently utilizes Automated Meter Reading (AMR) drive-by system to collect a single volumetric usage number once a month from over 1.4 million meters. Current metering, technology in service for most customers, measures and stores total usage for a single month. This number is collected and stored in the Company's meter data management system ("MDMS") for billing purposes.

Since 2018, the Company has installed 28,239 production solar meters across its Massachusetts electric service territory. The Company collects and processes solar production data through its AMR system monthly. The Company offers demand and time-of-use rates for commercial and industrial customers. Consumption meter data is collected monthly using the AMR system, which also has the capability of "resetting" the demand register for next billing cycle. For customers who opt-in to a time-of-use rate, the Company utilizes the MV-90xi system to collect and process their meter consumption data. This data is then sent to the Company's billing system to generate a bill for the customer.

4.7.11. Advanced Load Flow

The two overarching objectives for the Advanced Load Flow (ALF) project are:

- Provide Engineering and Operations with a robust circuit modeling tool, derived from the Geographic Information System (GIS) and other actively managed data sources to enable more comprehensive distribution planning, distributed generation impact analysis, operations contingency planning and decision making;
- Assess and improve source data and systems to build and maintain circuit models with the necessary quality for load flow and DMS tools;

More specifically, this project will support the Eversource need to develop advanced load flow capability. This is the ability to automatically build a model of the distribution system in order to study the impacts to the distribution system for multiple cases under multiple configurations in order to: (1) optimize its capital asset deployment, system planning, real-time loading and contingency scenario planning, and interconnection; and (2) enhance the capability of its distributed energy resource group study.

Business and operational benefits include:

- Common load flow planning environment across Massachusetts that allows consistent methodology and results across the state and serve as a foundation for CT and NH in the future;
- Common processes for model build and model maintenance;
- Enhanced analytical functions;
- Provides foundational support against which to evaluate the benefits achieved from DMS and VVO system investments.

The ALF process has currently known issues that prevent it from being a fully automated data source to Eversource's main simulation tool "DNV Synergi Electric". The issues are related to data source issues, such as missing or incorrect grid-representing data. Other complications are rooted in the difference in the various data sources in the four main regions of Eversource (EMA, WMA, CT and NH), such as unified variable name conventions and string coding. These issues are known, and mitigation is being considered. One project that mitigates certain issues it's the "GIS consolidation" project.

4.7.11.1 Planning Tools

Synergi Electric

This project will support the Eversource need to develop advanced load flow capability. This is the ability to automatically build a model of the distribution system to study the impacts to the distribution system for multiple cases under multiple configurations in order to: (1) optimize its capital asset deployment, system planning, real-time loading and contingency scenario planning, and interconnection; and (2) enhance the capability of its distributed energy resource group study. The three overarching objectives for the Synergi Electric tool are:

- Provide Engineering and Operations with a robust circuit modeling tool, derived from the Geographic Information System (GIS) and other actively managed data sources to enable more comprehensive distribution planning, distributed generation impact analysis, operations contingency planning and decision making.
- Assess and improve source data and systems to build and maintain circuit models with the necessary quality for load flow and DMS tools.

Provide an automated solution for generating segment level hosting capacity results for all distribution circuits.

PSCAD

For dynamic processes, such as switching impact studies, lightning impact studies and other transient-related impact studies, PSCAD is a different electric simulation tool that requires a different model build process. Ideally, static studies and dynamic studies could be performed in the same environment. This would lead to a lean automated load flow system that could serve both needs at the same time. Resource optimization for modelers would be possible and a more effective workflow for model studies and model management would be the result.

For dynamic processes, such as switching impact studies, lightning impact studies and other transient-related impact studies, PSCAD is a different electric simulation tool that requires a different model build process. Ideally, static studies and dynamic studies could be performed in the same environment. This would lead to a lean automated load flow system that could serve both needs at the same time. Resource optimization for modelers would be possible and a more effective workflow for model studies and model management would be the result.

4.7.12. Advanced Forecasting

As part of MA DPU 20-74 the Company was awarded funds to develop an Advanced Forecasting Capability. For details on this now existing technology platform, please refer to Section 5.1.1.10 as part of the Forecasting Methodology description.

5.0 Five- and Ten-Year Electric Demand Forecast

Section Overview

Eversource's futuristic advanced forecasting and modeling capabilities[108] allow for granular hourly analysis and projection of impacts of the Commonwealth's Clean Energy Climate Plan on the local distribution system. The Department of Public Utilities' (DPU) approval of Grid Modernization planning and forecasting tools and partnerships with Mass CEC and with up-and-coming firms focused on developing analytical software provided the Company with the ability to forecast a) customer propensity to adopt rooftop solar, b) economic growth of ground mounted solar using a combination of hosting capacity, land use permitting rules and costs, c) customer adoption of electric vehicles and associated charging location and time periods, d) new large customer connections – locations, magnitude and uncertainty, e) translating heating space demand at different weather conditions into electric demand with conversion to heat pumps and finally being able to overlay these projections onto existing hourly load shapes to recreate future hourly demand shapes resulting from the commonwealth's policies – at a distribution feeder level geo-targeted granularity. These innovations in advanced forecasting are a pre-requisite to EDC efficient distribution capital investment decisions by pinpointing where the constraints on the distribution system are projected to manifest.

The result of this in-depth modeling is a forecasted 16% increase in net electric demand in the ten-year forecast period raising the total peak demand in the Commonwealth served by Eversource from 6.1 GW to 7.4 GW.

The resulting headroom – endogenous to the forecast overlaid on the infrastructure capacity as well as internally consistent with the major bulk substation upgrades and associated implementation timeline – is translated into a kW per Capita available electrification hosting capacity in each municipality within Eversource's EDC territory. This electrification hosting capacity in each municipality can be further expanded into each community within a municipality – specifically larger cities like City of Boston which may have specific neighborhoods supplied by different large bulk substations. This information now equips city planners and policy makers to drive electrification programs into these communities to maximize clean energy deployment while also aligning with the capacity of the grid in those local distribution systems. With this information, city planners and

[108] The Commonwealth of Massachusetts Department of Public Utilities. "MA D.P.U. 21-80 Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Grid Modernization Plan for calendar years 2022 to 2025"

policy makers can target electrification in areas that are electrification ready.

Deploying and upgrading electric infrastructure is a time-consuming process from planning, design, siting, permitting, and construction. To ensure that there is always sufficient capacity on the system, the Company plans its infrastructure 10 – years into the future, thus allowing enough time for necessary work to complete before a certain need is realized.

The Company's planning cycle begins with a forecast of load and demand growth over the 10-year planning horizon. On an annual basis, the Company projects the peak electric demand at every distribution bulk substation to assess distribution equipment ability to serve the load within thermal capacity limits over time. These forecasts are issued in the first quarter (Q1) of every calendar year and used to identify capacity violations and reliability needs for which the Company would develop solutions and capital projects to resolve. The most recent available forecasts across the system show significant load growth through step load additions[109], driven directly by economic development in the region, adding more than 10% over the next decade to the current base load demand. These step load additions, however, show wide disparities between various regions, with the Boston Metro regions adding 30% of current base loading in 5 years, and other regions showing almost no step load growth. Electric vehicle charging demand is the second largest load contribution on the system, with an estimated total of 3% (relative to current peak) of residential charging (not including large fleet charging operations or DC fast chargers). In aggregate, load growth over a ten-year period, especially for the Metro regions, is driven almost exclusively by step loads stemming from the rapid economic development in the greater Boston area. This regionalized intensity is driving significant new transmission and distribution investments in the Metro Boston area.

Electric heating is currently not contributing to the system peak as electric heating is primarily used in the winter, and the Company presently operates a summer peaking system (July 2023). This means that the Company is forecasting and building its system to a summer peak forecast. Across the service territory, the 2022/2023 Winter Peak was about 20% below the 2022 summer peak. This capacity buffer allows for a delayed impact of heating electrification with a system wide transition to a winter peak expected in 2035, with individual stations transitioning earlier or later. As a result, the 10-year peak forecast does not show the direct impact of heating electrification occurring in the winter.

[109] Step Loads represent large (> 500kW or >1 MW depending on system) new load additions which can come from new buildings, or re-development of existing sites. These step loads can include residential developments, C&I, large standalone storage systems, fleet charging operations, and more. See Section 5.1.4.

Review of Assumptions and Comparison Across EDCs

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

The amount and rate of deployment of total installed solar capacity is specific to each utility and described further in section 5.1.2. Eversource and National Grid use the same software to predict parcel wise allocation of ground mounted solar installations. However, the underlying parcel, land use data, and method of simulating region-specific PV adoption is the same; based on land parcel availability and profitability analysis. Unitil forecasts future solar capacity based on historical trends.

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

Methodology

The Company commences the annual forecasting cycle after each summer peak load season (June – August) and completes the forecasts by March of the following year. The first step in each forecasting cycle is the documentation of the reported net station peaks at each distribution bulk station in the Company's territory. Each reported station peak is then corrected for local conditions such as any load transfers at time of peak, back up generation that might have been running on the system, solar generation contribution, and the prevailing weather conditions at the time. The result of these adjustments yields the reported, weather normalized, 90/10 gross station peak as shown in Figure 71 below.

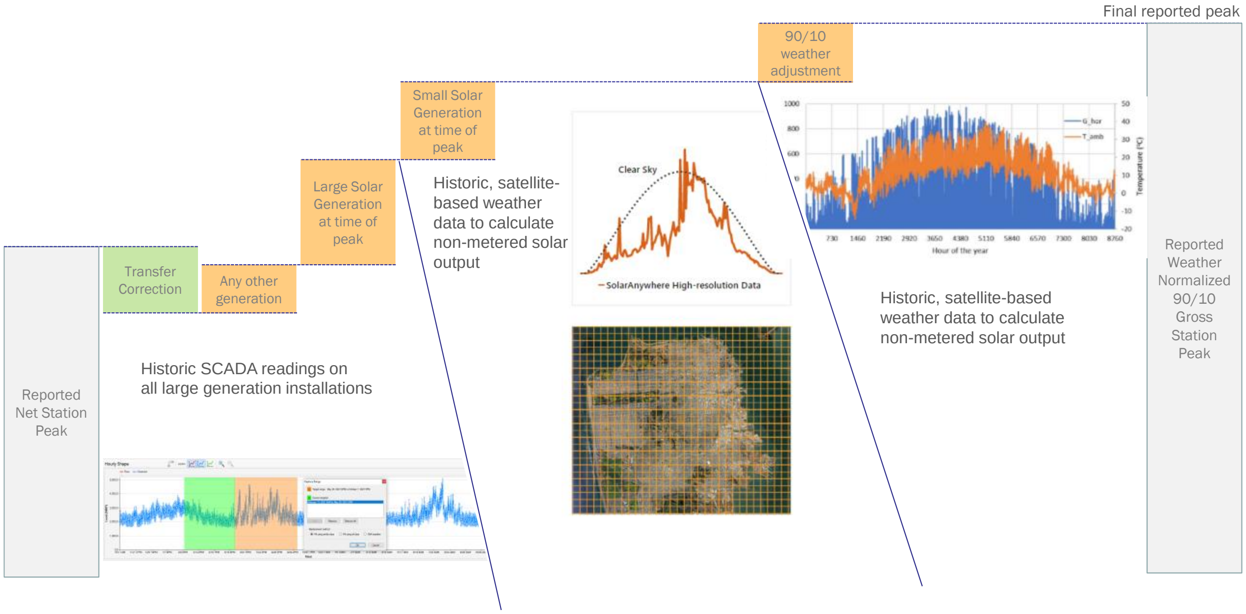


Figure 71: Adjustments to Reported System Peaks

These reported, weather normalized, 90/10 gross station peaks are then used, in combination with the economic data provided by Moody's[110], to determine the trend in load growth relative to the development of the economy, which in turn allows a forecasted trend to be developed for the next 10 years based on economic projections. After a trend forecast is produced, the net forecast is derived by adjusting for EE, solar, EV, and large customer projects. Company-sponsored EE projections are based on the most readily available three-year plan, while solar projections are developed consistent with historical trends. Naturally occurring EE (i.e. reduction in demand due to non-programmatic improvements in end-use efficiency) is captured in the trend forecast.

The Company's forecast includes a significant increase in the penetration of electric light duty passenger vehicles. Large development projects (step loads) that the Company has specific knowledge of, and which econometric trend forecasts could not otherwise predict, are also added to the Company's forecast.

Each substation's peak load forecast is a function of the substation's historical peaks and the relevant Operating Company's peak load history and forecast. Manual adjustments are made to individual substation forecasts for: (1) specific, identified large development projects and

[110] Moody's Analytics provides comprehensive economic data and forecasts at the national and subnational levels.

expected changes in system configuration or operation that could not otherwise be predicted by the Operating Company's econometric forecasts or an individual substation's share of those forecasts; (2) Company-sponsored EE and behind-the-meter solar installations which decrease the forecast (See Section 9.3 on Naturally Occurring NWA); (3) EV additions which increase the forecast. The result of these adjustments yields the weather normalized, 90/10 net station peak load forecast as shown in Figure 72 below.

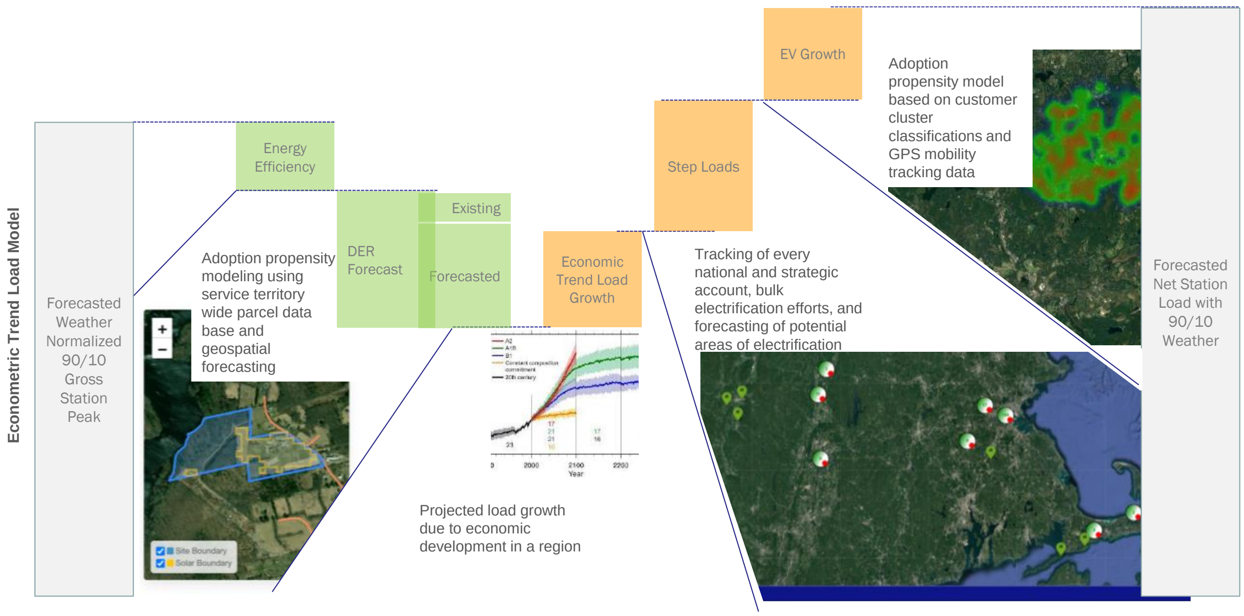


Figure 72: Adjustments to the Econometric Trend Load Forecast

In compliance with the Department's guidance in D.P.U. 13-86, the Company has amended its load forecasting methodology to change how it reconstitutes loads for distributed generation. The Company no longer reconstitutes loads for distributed generation units larger than 5 MW, unless those customers are on Standby Delivery Service. For customers on Standby Delivery Service, the Company is obligated to be "*standing ready to provide delivery of electricity supply to replace the portion of the Customer's internal electric load normally supplied by the Generation Units be unable to provide all, or a portion of, the expected electricity supply*."[111]

It is the Company's obligation to provide service to these customers regardless of whether the generation units that can serve a portion of the customer's load are operating. To reflect this obligation, forecasted loads are reconstituted for the portion of load that may be served by the generation units.

[111] See M.D.P.U. No. 255F, page 2 of 6.

EVERSOURCE

The Company produces both a "normal" and an "extreme"' peak load forecast by each Operating Company. The normal peak load is based on average historical weather data, and the extreme peak is based on the 90th percentile of that historical weather data. These weather assumptions are the only differences between the normal and extreme peak load forecasts. Both Distribution and Transmission System Planning groups utilize the 90/10 weather data for their peak load forecasts in their planning efforts to assess the ability of the electric infrastructure to meet customer needs safely and reliably during extreme, but realistic, weather events.

Energy Efficiency

The Company's load forecasting and transmission planning efforts are performed against the backdrop of the Company's aggressive and industry-leading energy efficiency programs, which not only incentivize energy conservation measures, but increasingly also support building electrification (e.g., adoption of heat pumps). Eversource offers EE programs across all customer segments, including residential, low income, and commercial and industrial ("C&I"). Program offerings typically include incentives for new construction projects, retrofits, and energy efficient products/appliances. The Company considers these investments the most economical way to reduce the region's emissions and increase its economic competitiveness. The Company's 2022-2024 Three Year Energy Efficiency Plan calls for an investment of over $1.2 billion in electric energy efficiency and electrification programs.

The results of the Company's energy efficiency efforts are reflected in the load forecast in two ways. Past efforts are implicitly reflected in the historic peak loads used for the trend forecast. Future potential EE efforts are then included as forecast adjustments. Energy Efficiency planning occurs within its own adjudicated dockets every three years, and as the outcome of future dockets cannot be known, the Company does not attempt to forecast energy efficiency savings beyond the current period. Rather, the Company includes in the forecast adjustment a scenario that shows what the cumulative impacts of EE would be if a continuation of existing programs at similar funding levels yielded historically consistent impacts.

Rooftop Solar

Rooftop solar projects tend to be smaller in size, with higher residential penetration, therefore different methods are used to assess rooftop solar than ground-mounted solar. Currently, Eversource applies a system of regression models to predict rooftop solar adoption in Massachusetts. The tool is built on Eversource data including historical consumption and customer load profiles, electric utility rates as well as US census data. Data is collected internally from Company databases and sourced externally from public and private entities.

The model forecasts rooftop solar adoption using a two-part process: annual solar deployment and regional level adoption.

Annual Solar Deployment

The annual solar deployment is determined based on historical trends, the number of potential adopters and top-level targets. The total number of potential adopters at a system level for each customer type is calculated based on the number of existing customers, new customer growth, and assumptions on the proportion of customers that have access to solar (i.e., live in an area with sufficient exposure of sunlight or housing configuration that allows for solar panels to be installed). Customer type is defined as residential or commercial and industrial based on the rate code that is applied for the customer. The rate or proportion of customers at a system level that adopts solar in a certain year is estimated by applying an econometric model. The econometric model considers multiple variables and their values in the year of interest and generates a prediction. The model is trained and validated using historical data for the variables of interest. The amount and period of historical data used depends on data availability for a given customer type. The rate of adoption and number of adopters are also compared to state level (Massachusetts Decarbonization Roadmap and Clean Energy and Climate Plan) estimated growth as a benchmark. To ensure consistency, the predictions are constrained by these top-level state and regional projections, i.e. Eversource territory adoption is limited to the total predicted for the state. The main variables in the econometric model are included in the table below for reference.

Table 28: Rooftop Solar Electric Demand Assessment – Annual Adoption Model Variables

Variable	Units	Description
Existing penetration	N/A	Proportion of pool that already adopted
Customer payback period	years	Number of years to recoup investment
Cost of PV system	$/W-AC	Total cost to install and purchase equipment for system
Solar incentives	$	State or other incentives
Tax credits	S	Federal tax credit (ITC)
Interest in solar and renewable energy	N/A	Google search index for annual interest in solar and renewable energy
Electric rate	$/kWh	Existing electric rate for customer

Solar adoption forecasting is heavily reliant on input variables. As such, each input variable is monitored and updated based on its outlook and there exists a degree of uncertainty or fluctuation due to policy direction. Considerations for solar deployment include installation costs, incentives, and expected payback for customers. Certain inputs are 'raw' variables, such as the Federal Tax Credit, and are directly incorporated into the model. Other inputs are 'derived' variables, such as customer payback period, which are first calculated using individual customer type rates and cost assumptions, economic impacts such as inflation, and so on. Input variables are not static and may change year to year.

Regional Level Adoption

The second part of the rooftop solar adoption process involves predicting a more granular level adoption than at the system level. In essence, the system level customer type predictions for total adoption are then further allocated to specific sub-regions (currently zip codes, but able to aggregate up or drive down further with sufficient data). The regional level adoption considers geography-specific (zip code) variables including land cover area, population density, proximity to other adopters and average age of homes. Similarly, a regression model is also employed for the purposes of estimating adoption. The main variables in the geography centered econometric model are included in the table below for reference.

Table 29: Rooftop Solar Electric Demand Assessment – Geographic Adoption Model Variables

Variable	Units	Description
Homes	N/A	Number of single family occupied detached homes
Median income	$/year	Median income of households
Age of householder	years	Average age of head of household
Education of householder	years	Average education of head of household
Population density	People/km^2	Population density
Gini Index	N/A	Measure of inequality
Proximity to previous adopters	Systems/km^2	Existing installation density
Age of home	years	Average age of home
Rooms	N/A	Average number of bedrooms
Vehicles	N/A	Average vehicles per household
Land cover area	% Coverage	-Covered by trees -Developed Open -Developed low density -Developed medium density -Developed high density -Developed area low or medium density / All developed area -Developed area high / All developed area -Agricultural land

The company is developing a forecast based on similar principles and data to predict areas of adoption in Connecticut and New Hampshire.

In addition, Eversource incorporates weather and irradiance data to forecast solar generation potential on an hour-by-hour granularity. Solar, both rooftop and ground-mounted, can offset the peak load in the forecast. Hereby, the installed capacity, as well as the forecasted output of solar are considered (see Section 5.1.2.4 for details). The potential power from photovoltaic (PV) installations is modeled using solar irradiance models acquired from third party consultants. Using historical weather data to correlate relative irradiance to peak gross station load, the Company developed a probability model to adjust solar output at a 90/10 probability for overcast weather conditions during peak days. This reduces the modeled solar output for load planning purposes. Figure 73 below displays a sample extract of solar irradiance data over a particular summer day that is used in the calculation of potential power in a specific region. This applies to both rooftop and ground mounted solar.

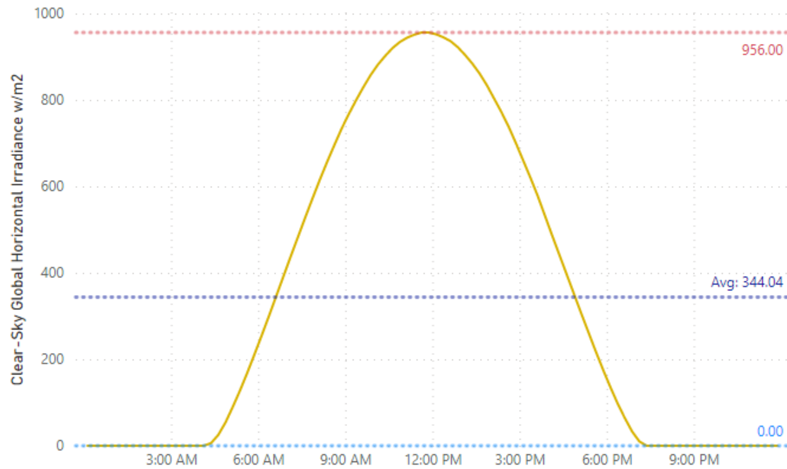


Figure 73: Sample 24 Hour Solar Irradiance Profile for July 1, 2022

Ground Mounted Solar

Ground mounted solar is expected to comprise 70% of installed solar capacity in Massachusetts by 2050,[112] therefore it is important to identify and enable areas of high potential. Ground mounted solar projects tend to be exclusively commercial initiatives in more remote areas and as such require a different approach to forecast compared to rooftop solar adoption. Eversource Energy has deployed a software platform[113] that can:

a. Assist solar developers with utility interconnection, mapping, and parcel identification for ground mounted solar projects in Massachusetts, Connecticut, and New Hampshire.
b. Calculate the technically available land for solar and the amount of generation potential from this land.
c. Forecast the development of solar projects based on project economics.

A sample of a parcel identified as potential target for ground mount solar development from this software platform is shown below.

---

112 Massachusetts Executive Office of Energy and Environmental Affairs (EEA). “MA 2050 Decarbonization Roadmap”, 2020. https://www.MAgov/doc/ma-2050-decarbonization-roadmap/

113 Eversource Interconnection Analysis Portal for Developers. https://www.eversource.com/content/residential/about/doing-business-with-us/interconnections/interconnection-analysis-portal

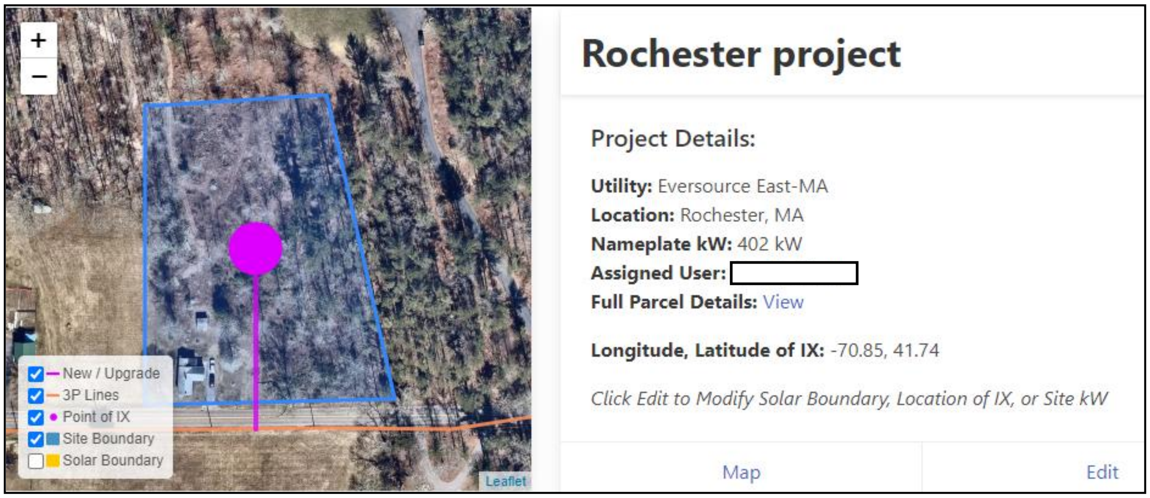


Figure 74: Sample of Parcel Identified as Potential Ground Mount Solar Development Project

The annual ground mounted solar deployment is determined by state level projections, with adjustments in the near term for planned projects. Projects are forecasted to develop in order of high to low rate of return on investment (ROI) for the customer; the project and its required capacity is assigned to the associated substation if capacity is available. Three main factors affect development of ground mount solar projects: <u>cost</u>, <u>infrastructure capacity</u>, and <u>land use constraints</u>. Land use restrictions depend heavily on regulatory guidance.

The lack of available infrastructure capacity can severely hamper forecasted solar build out as clearly evidenced in Section 5.4.6 and 5.5.6. Specifically, in the EMA South Sub-Region almost no remaining stations still have available hosting capacity. This forces the model to allocate the annual incremental solar change to other regions, among others Metro – West. However, once the submitted CIPs are approved, the Company would re-run the analysis to assess how this will re-direct development from the Metro Regions to EMA South and WMA.

The steps in the simulation which ranks parcels and allocates deployment is summarized as follows:

1. The annual ground mounted solar deployment in Massachusetts as set out in the state level projections is applied, with adjustments in the near term for planned projects.
2. Calculate the Net Present Value (NPV) and Internal Rate of Return (IRR) per project (per parcel)
    a. Project economics estimates: capital and operating costs, land cost, municipal restrictions, interconnection cost, site specific costs, equipment, incentives, and revenue from power generation potential
3. Projects are forecasted to develop in order of high to low IRR projects; the project and its required capacity is assigned to the associated substation if capacity is available
    a. The software calculates the distance to the nearest distribution feeder based on publicly available hosting capacity map data

4. If the substation existing hosting capacity is exceeded, projects can no longer be added to that station in the current year. If there is a planned upgrade in a future year, the project can be enabled in that year.
5. Once the allotted annual solar deployment is reached, the cycle starts for the following year
6. At the end of the forecast simulation, all the technically feasible projects in Massachusetts, their associated station, and their order of deployment are generated
7. The power generation is calculated by scaling a representative solar power generation profile for the region by the project capacity

The following table describes the various land use layers that are included in the tool for the sensitivity scenarios considered in the analysis. To allow flexibility for future policy decisions and different land use restrictions, sensitivity analyses are conducted for varying combinations of land use restrictions. In the current base case forecast, all technically available land is assumed to be developable for solar and included in the forecast. This allows for the least constrained analysis that is primarily driven by solar developers and project economics.

Table 30: Ground Mount Solar Land Use Descriptions

Category	Land Use Layer	Description	Source
Environmental	Priority Habitat	The Priority Habitats of Rare Species data layer contains polygons representing the habitats of state-listed rare species in Massachusetts. Priority Habitat polygons are the filing trigger for project proponents, municipalities, and all others for determining whether a proposed project or activity must be reviewed by the NHESP for compliance with the MA Endangered Species Act and its implementing regulations	(NHESP, June 2014)
	Core Habitat	A collection of specific areas necessary to promote the long-term persistence of state-recognized Species of Conservation Concern, exemplary natural communities, and intact ecosystems	(NHESP, June 2014)
	Critical Natural Landscape	Intact landscapes in Massachusetts that are notably apt to supporting ecological processes and disturbance regimes, and a wide array of species and habitats over long time frames	(NHESP, June 2014)
Conservation	Article 97 Land	Conservation and outdoor recreational facilities owned by federal, state, county, municipal, and nonprofit enterprises are included in this data layer. Not all lands in this layer are protected in perpetuity, though nearly all have at least some level of protection	(EOEEA, April 2022)
	Prime Farmland	Land that has the best combination of physical and chemical characteristics for economically producing sustained high yields of food, feed, forage, fiber, and oilseed crops, when treated and managed according to acceptable farming methods	(USDA NRCS, November 2021)
	Farmland of Unique Importance	Land other than Prime Farmland or Farmland of Statewide Importance that might be used to produce specific high value food and fiber crops	(USDA NRCS, November 2021)
	Farmland of Statewide Importance	This is land, in addition to Prime and Unique farmlands, is of statewide importance to produce food, feed, fiber, forage, and oil seed crops, as determined by the appropriate state agency or agencies. Generally, these include lands that are nearly prime farmland and that economically produce high yields of crops when treated and managed according to acceptable farming methods	(USDA NRCS, November 2021)
	State Register	Points and polygons maintained by the Massachusetts Historical Commission including the Inventory of Historic Assets of the Commonwealth, National Register of Historic Places nomination forms, local historic district study reports, local landmark reports, and other materials	(Massachusetts Historical Commission, July 2022)

Category	Land Use Layer	Description	Source
Wetlands	Wetland Resource Area	Wetland areas consist of open water, vegetated wetlands, and coastal landforms. Hydrologic connections may consist of rivers, streams, ditches, culverts, swales, or other water conveyance features	(Massachusetts DEP, December 2017)
Brownfields	Brownfield	Sites and parcels that are classified under Massachusetts chapter 21E have been contaminated with oil and/or hazardous material releases	(Massachusetts DEP, Dec 2021)
	Landfill	The Solid Waste Diversion and Disposal Data layer was compiled by the Department of Environmental Protection to track the locations of land disposal of solid waste. This statewide data layer contains most locations currently regulated under MassDEP's solid waste regulations (310 CMR 16.000 & 19.000)	(Massachusetts DEP, January 2016)
Land Parcels (Fixed)	Parcel Boundaries, Assessed Cost	MassGIS standardized assessors' parcel mapping data set contains land lot boundaries and database information from each community's assessor. From each community, vendors deliver an ESRI file geodatabase to MassGIS. MassGIS staff reviews the parcel boundary mapping and aggregates it into a centralized state map.	(MassGIS, July 2022)

Weather Adjusted Firm Solar Capacity Model

As the company includes forecasts of installed solar capacity in its ten-year forecast, adjustments must be made to the expected solar output as solar requires not only a forecast of installed capacity but likely coincident output at peak hour. Solar is highly dependent on the time-of-day and the weather conditions prevailing which requires adjustments to the modeled output. E.g., a station peak at 5pm might at best, under ideal weather conditions, be able to see 40% of the installed solar capacity to offset its peak. With solar being included in the forecast, however, it acts as a non-wires alternative by deferring investments into load-heavy stations. However, to consider a "firm" solar contribution or a dependable output, the Company must consider adverse weather impacts and their likelihood, such as hot, humid, and overcast days. During these conditions, failure of solar to appear at modeled output would lead to overloading of the stations. This is done for both the existing and forecasted solar capacity.

The Company conducted a statistical analysis using historic relative irradiance values (actual historic irradiance over ideal irradiance at the time) and mapped it against the gross station loads in specific locations across its MA territory. The key take-away from this analysis, shown in the yellow circle in Figure 75, is that significant reductions of relative irradiance during times of gross station peak can and must be expected. This supports the finding that solar, in the Company forecast, must not only be adjusted for time-of-day, but must also include a 90/10 weather adjustment to ensure that any modeled solar output is sufficient to reliably offset a station need by reducing the forecast. In other words, the possibility that solar would not show up when it is needed to reduce station loading must be accounted for during planning.

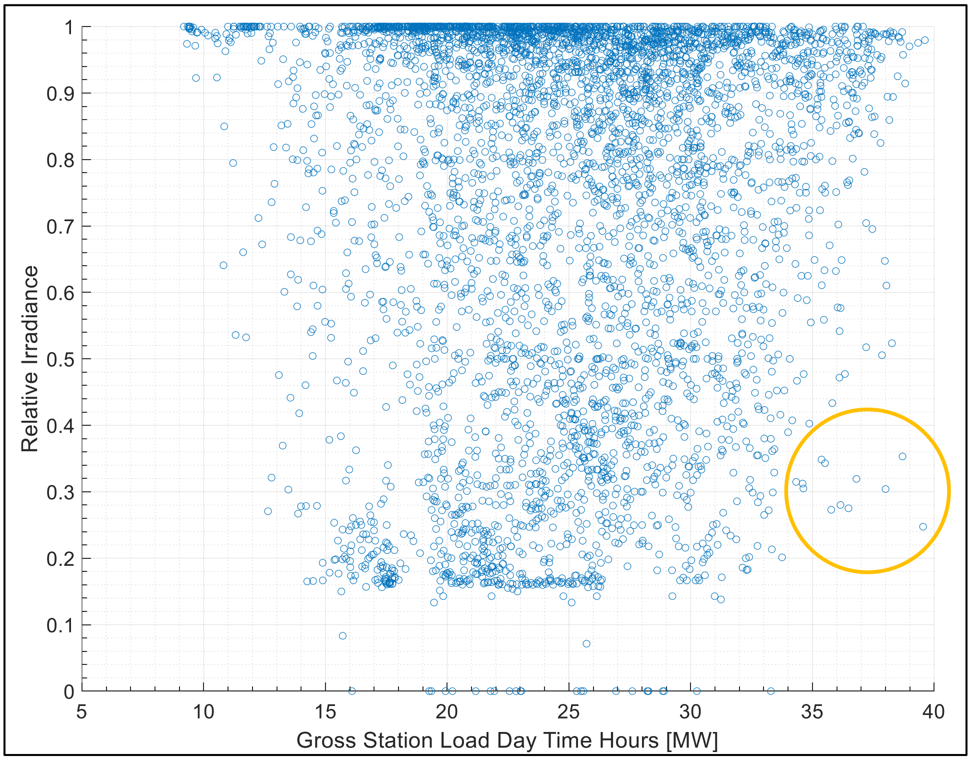


Figure 75: Relative Irradiance Data Sample over Gross Station Load

The modeled solar output of any installation is a complex function of the installed solar panel capacity P_{DC}, the solar irradiance at the time $I_{solar}(t)$, the installed inverter capacity P_{AC}, and a wide array of inputs, such as angles of installation covered under the constant C. The relationship is expressed as:

$$\mathrm{P_{AC}(t) = f(P_{DC}, I_{solar}(t), P_{AC}, C)}$$

Specifically, however, P_{DC} is important for calculating firm solar output. For example, a solar installation with 5 MW P_{AC} and 5 MW P_{DC} will put out 2.5 MW at half of rated irradiance while one with 5 MW P_{AC} and 10 MW P_{DC} will still be putting out 5 MW at half of rated irradiance. This is commonly referred to as "overclocking" of inverters. The Company therefore continuously observes and studies the overclocking trends in the solar industry to adjust its models correspondingly. The higher the overclocking of inverters, the less susceptible the installation are to a lower relative irradiance as shown in Figure 76.

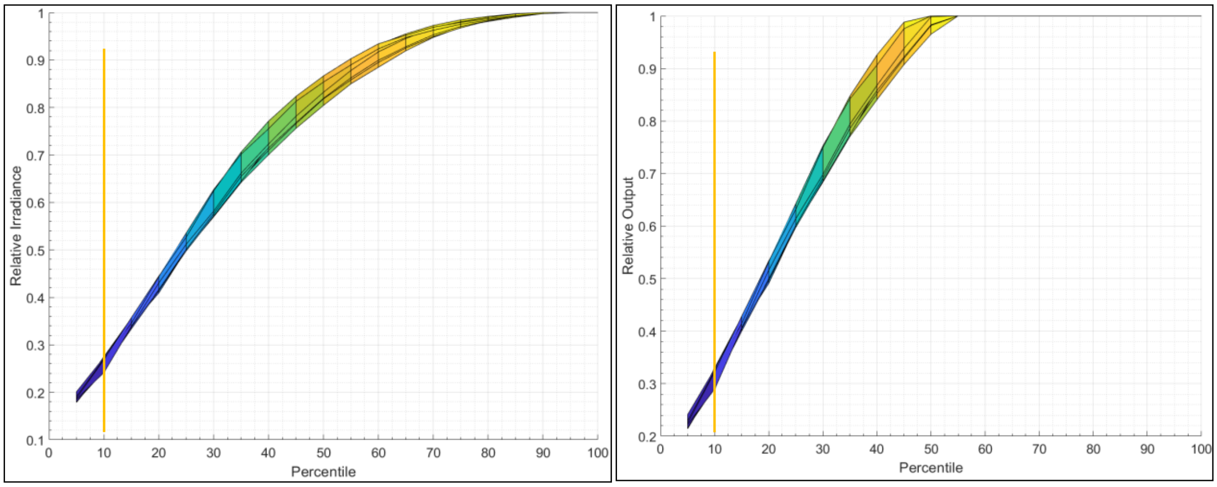


Figure 76: a) Historic Weather Percentiles Against Relative Irradiance and b) Impact on Relative Output with 20% Overclocking of Panels during Summer Month.

The resulting adjustments to the clear sky profile when including installed (existing and forecasted) solar capacity into the forecast determined by the Company are shown in Table 31.

Table 31: Firm Planning Adjustments for Solar Output

	Winter	Shoulder	Summer
10th percentile relative irradiance	16.8%	18.1%	24.1%
10th percentile relative output on nameplate rating with 20% overclocking	20.2%	21.7%	29.0%

These insights are critical in understanding how solar might help offset station peaks in load-driven regions. Particularly in the long-term forecasts as the Company expects the system to transition into a winter morning peak between 2030 and 2035, the expected contribution to load reduction by solar will be significantly diminished.

The following Figure 77 shows the difference between the relative Clear-Sky Output, showing the percentage of installed $P_{AC}(t)$ over two days assuming ideal weather conditions (orange trace), the relative Historic Output, showing the percentage of installed $P_{AC}(t)$ based on historic irradiance data (blue trace), and the relative Planning Output, showing the percentage of installed and forecasted $P_{AC}(t)$ that will be included in the forecasted peak and planning models (grey trace). The orange trace caps off at 100% as the model includes an over installation of panel capacity to AC inverter capacity with a factor of 1.2. These values are from June 2022 and show how the Planning Output matches the historic output of the first day shown. To ensure that solar, which is considered an NWA as part of the forecast, is modeled in the correct capacity to offset load need reliably, this relative Planning Output is used.

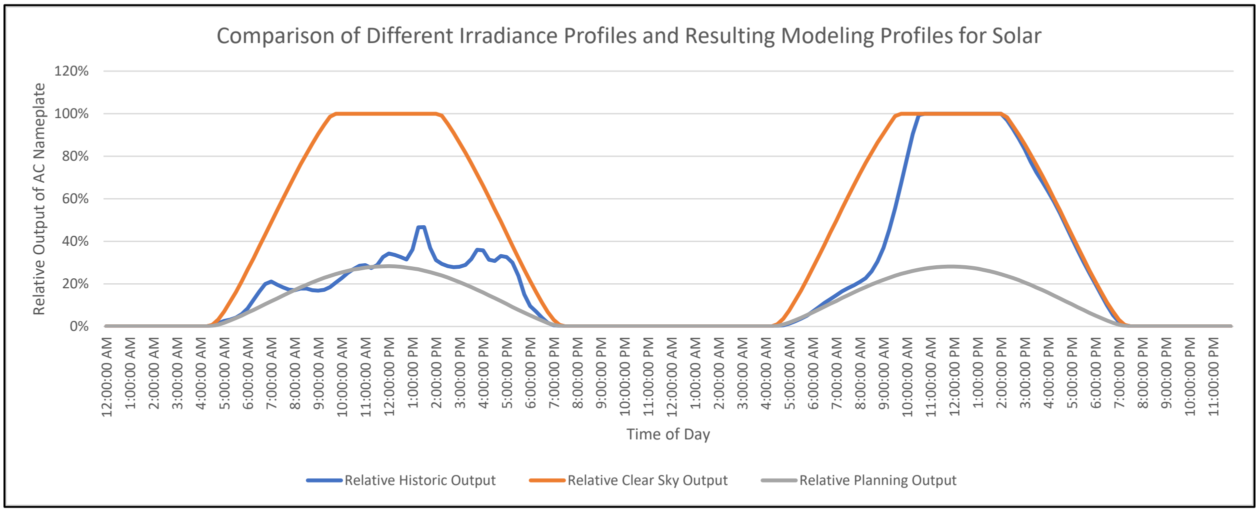


Figure 77: Historical June 2022 data showing Relative Historic, Clear-Sky, and Planning Output

Step Loads

Step Loads represent large, new load additions to the Company's substations. These step loads can include anything from new C&I development, upgrades to existing sites, large multi-unit residential developments, grid-charging battery storage, or EV charging sites. Typically, the Company will track these incremental load increases starting at a 500kW or 1000kW threshold, depending on if the load addition is associated with a distribution non-bulk station or a bulk substation respectively.

The Company relies on its Strategic and National Account Executives, who collectively manage more than 5,400 accounts in various locations, to get an early indication of customer development plans. From there on, step loads undergo an evolution of certainty within the tracking system.

1. **Certain:** A work order signed, and payment has been received
2. **Probable:** Public statements have been made and permits requested, or other actions have announced the customers intention to the broader public making a withdrawal less likely
3. **Possible:** Customer is engaging with Eversource in earnest discussions about the project, distribution engineering is included, and some public statements have been made
4. **Uncertain:** Discussions happen only with strategic and national accounts and at a conceptual level
5. **Forecasted**: Assumed load potential based on state or local electrification objectives and customer goals

The challenges with step loads are that they tend to be heterogeneous, and do not lend themselves to trending based on history, and therefore the Company is heavily reliant on customer-provided information to accurately model the impact on forecasted demand, both in terms of timing and magnitude. Firstly, if customers do not communicate intentions until they file a load letter with the Company, there is little chance of the load being identified early enough to provide lead time for planning. To alleviate this issue, the Company works in close cooperation with municipal governments to understand which projects might be in the early approval stages for permits, bringing more certainty earlier in the process. However, given the number of municipalities in the state, as well as the lack of a standardized system for tracking and reporting permits, this is representing a significant effort for the Company and so might only be feasible for select cities with significant load growth and tracking databases.

Secondly, step loads currently account for almost all near-term projects that are load-driven with more than 98% of the ten-year load growth expected to come from step loads. Therefore, step loads are the primary driver for substation capital investments undertaken by the Company, which in turn exposes the Company's capital plan to the risk of changes to the developer projects – a canceled project could mean a substation upgrade is no longer needed in the near-term, or a last-minute change to add significant EV charging capabilities can pull a substation need to earlier than the Company can feasibly build requisite infrastructure. To account for these impacts, the Company treats step loads at each interval of certainty differently:

1. **Certain:** Projected loads are taken at 100% of rated capacity and expected to be online in 2-3 years.
2. **Probable:** Projected loads are taken at 100% of rated capacity and expected to be online in 3-5 years.
3. **Possible:** Projected loads are taken at 50% of rated capacity and expected to be online in 5 years.
4. **Uncertain:** Projected loads are taken at 25% of rated capacity and expected to be online in 6-8 years.
5. **Forecasted**: No direct load projects are made. Stations are ranked by potential forecasted step load impacts to the system, with the highest at-risk stations receiving modified planning criteria (dropping of planning threshold from 90% to 80% of firm capacity) to ensure timely and detailed review.

The step load tracking process is updated as projects arise and fed into the ten-year forecast on a yearly basis. However, if step loads occur outside the forecasting cycle, the Company can make between-cycle updates to the ten-year forecast to adjust if needed. The charts in Figure 78 show the current step loads geographically distributed across the system as they are tracked today. Loads are tracked directly in the Company's Advanced Forecasting Solution, where the Company can assign specific load profiles to them.

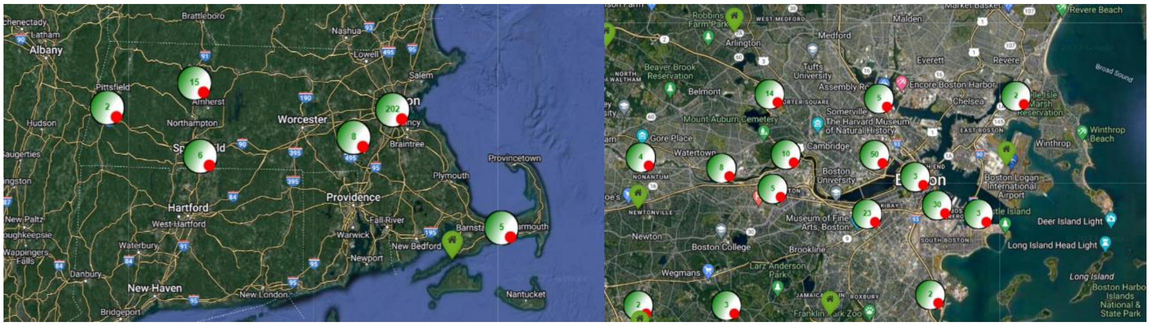


Figure 78: Current Number of Step Loads in the ES Service Territory by Location

Electric Vehicles

Electric vehicle adoption and charging are influenced by a variety of factors including consumer purchase trends, existing and planned charging infrastructure, and policy. To better assess the impact of electrification in the transportation sector, the Company employs a variety of analysis methods and data sources, including:

a. System level historical EV adoption and energy requirements - analysis starts with historical actuals and builds a projection based on national and local market information such as new EV model release plans, state rebate programs and state planned infrastructure investments. In the current iteration of the Company's system-level peak demand forecast, electric vehicles are included as an adjustment to the reference or base forecast. The forecast includes explicit additions to electrical energy output requirements and peak demand due to EVs.
b. Conversion required to meet state decarbonization goals – analysis examines the projected proportion of total vehicle stock that needs to be electric. The number of internal combustion engine (ICE) vehicles that need to convert to electric is based on state or local policy direction. Existing vehicle traffic patterns are used to estimate local potential charging demand.
c. Charging profiles and locations – analysis determines regions for charging infrastructure development. Amount and type of charging infrastructure needed to sustain the system level electric vehicle projections and likelihood of development of charging stations in certain geospatial areas are considered.

Electric vehicles are included in the ten-year demand forecast with their coincident demand at time of station peak load. Using a combination of top-down and bottom-up approach, a statewide EV forecast based on policy objectives is split between the bulk stations. The Company utilizes a travel model to determine when EV charging hits peak. The travel model uses advanced data analytics and GPS tracking data from cellular service and App providers to create travel profiles showing when, how many, and where vehicles terminate a trip. This then allows the creation of charging profiles for the company with temporal and spatial resolution. One important consideration is that this is done by season and day type (weekdays, Fridays, Weekend Days, and Holidays) to capture dynamics such as holiday travel on Cape Cod. The Company uses the same data vendor as the Massachusetts Department of Transportation ("MA-DOT") to ensure a consistent data basis for all planning entities within the Commonwealth.

The steps to determine EV adoption and charging patterns are summarized as follows:

1. The annual electric vehicle adoption in Massachusetts as set out in the state-level projections is applied, as a proportion of total vehicle stock – this includes new sales of EVs and conversion of internal combustion vehicles to EVs.
2. Collect the actual vehicle traffic data in a region (by zip code)
    a. Vehicle: vehicle type (heavy, light duty, medium), count vehicles entering a zip code
    b. Seasonality: type of day (Weekday, Friday, Weekend, Holiday, season (spring, summer, fall, winter)
    c. Location: zip code, substation (aggregated and mapped by zip code)
    d. Travel: average travel distance, stopping (dwell) time
2. Estimate EV adoption as a proportion of total vehicle stock – this includes new sales of EVs and conversion of internal combustion vehicles to EVs. The annual electric vehicle adoption in Massachusetts as set out in the state-level projections is applied for this purpose.
3. Calculate potential charging load required for all vehicles in the region. Using the average vehicle travel data (average distance, stopping time) and proportion of vehicles that are EVs, estimate the amount of electric demand. The total energy demand is the energy gained during the time period the vehicles remain stopped in the area up until the level of energy needed to recoup the energy lost during their last trip (on average). Assumptions for charging power are based on the type of charging application and charging scenarios.

The Figures 79 a-b below show samples of estimated local charging demand based on existing vehicle traffic patterns using this methodology. The figures show the simultaneous charging demand over a 24-hour period for light duty and heavy-duty electric vehicles in a specific region (here for example South Boston is analyzed). The charging demand can be used to analyze the coincident demand at time of station peak load for planning purposes. This combination of top-down and bottom-up data allows the Company to focus on areas and stations that may be at risk of overloading from additional EV load. As such the Company can utilizes the results of the model to inform charge management and plan for peak load events.

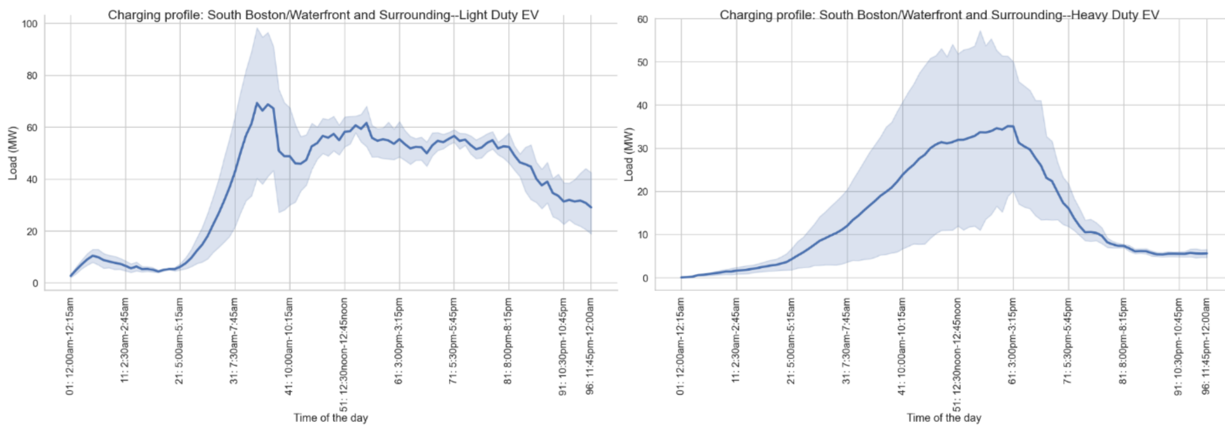


Figure 79. a) Sample Light Duty Electric Vehicle Charging Profile
b) Sample Heavy Duty Electric Vehicle Charging Profile

The general method described above assumes a constant rate of growth over all regions by applying the statewide trend to all regions. To analyze the potential for EV charging on a more granular level, varying growth rates by geography is applied. The Company developed an Adoption Probability Model to determine which area will see the fastest adoption of electric vehicles. Adoption Probability Models use socioeconomic data on customers, as well as policy information to derive which customers are most likely to adopt. The EV adoption rate models in Massachusetts are part of a Grid Modernization Project approved by the Department of Public Utilities' (the "Department") Grid Modernization Docket 21-69 in which the company is partnering with a wide variety of vendors to deploy advanced software solutions for the purpose of forecasting EV Adoption.

There are two main components of developing geography specific electric vehicle models:

- Vehicle adoption: using customer, zip code, and census-tract level information to predict the likelihood of customers adopting in a specific region
    - Socioeconomic data includes average income, education, age, population density, preference for clean energy technologies
    - Total adoption rates are informed by top-down, state level projections depending on the pathway
- Charging sites: using information about existing EV charging stations and parcel information, potential sites are selected for the specific charging station types. Traffic and travel data are also considered in correlation with existing stations.
    - Residential Charging: level 1 and level 2 chargers
    - Workplace Charging: commercial/business area with charging sites proportional to employees (if possible)
    - Public Charging: Level 2 and DC Fast Chargers at shopping centers, transit stations, and parking lots near highways

Heating Electrification

The Company's most current ten-year forecast issued in Q1-2023 does not yet include an electric heating component, as the forecast range does not yet show transition to a winter peaking system. However, starting with the forecast issued in Q1-2024, the Company will include a detailed heating electrification component for the ten-year forecast. It is expected that the first handful of stations, specifically stations in regions with aggressive heating electrification local ordinances, will show a winter peak transition in this timeframe.

For the ten-year winter peak forecast, the Company utilizes the Advanced Forecasting capabilities (See Section 5.1.1.9) which use an agent-based[114] adoption model (See Section 8.2) to project potential customer adoption of heating electrification throughout the system. The agent-based model is contained in the overall pathway model ("All Options Pathway") as outlined in the state's Decarbonization Roadmap. This ensures that the total annual adoption of electric heating technologies follows the state's pathways with a 5-year interval alignment for 2030 – 2050.

Agent-based models (ABM) are computer simulations used to study the interactions of individuals or groups of people, things, places, and time. They are stochastic models built from the bottom up meaning individual agents are assigned certain attributes. The agents are programmed to behave and interact with other agents and the environment in certain ways. Agent-based modeling differs from traditional, regression-based methods in that, like systems dynamics modeling, it allows for the exploration of complex systems that display non-independence of individuals and

Local Adjustments

While the Company bases its ten-year forecast primarily on regression and adoption propensity models and not on policy drivers (those play into the long-term electrification demand), some local adjustments must be made for communities that have developed aggressive decarbonization goals that are above and beyond the 2050 decarbonization roadmap. While there are significant technical challenges to the accelerated timelines that will be discussed in Section 8. The Company must be able to understand and account for local load impacts. Local adjustments are made by introducing updated localized adoption estimates for municipalities that accelerate the deployment of electric vehicles, heat pumps, or solar installations in a specific region. The result is a policy-driven impact on the ten-year forecast that is above and beyond a normal adoption and regression model. In all cases, the Company assumes full

[114]Columbia University Mailman School of Public Health. "Agent-Based Modeling". https://www.publichealth.columbia.edu/research/population-health-methods/agent-based-modeling

compliance with local goals, laws, and ordinances, even if they allow for "penalty payments" for non-compliance. This is because the Company cannot plan the system based on an assumption that some residents may not comply with local laws and ordinances. This is especially the case if the local laws and ordinances request a technology-specific solution, such as electrification of heating, and do not leave room for alternative zero carbon technologies.

Two key local initiatives, among many, are:

- The Building Emissions Reduction and Disclosure Ordinance (BERDO) in Boston
- The Building Energy Use Disclosure Ordinance (BEUDO) in Cambridge

With the ten-year forecast that will be issued in Q1 2024, the Company will have the ability to incorporate local ordinances, such as the two listed above, for the first time.

Battery Electric Storage

Battery electric storage systems (BESS) are an integral part of an electrified future power system, and the Company is observing a significant uptick in applications for stand-alone, front-of-the-meter (FTM), BESS. BESS technologies, however, pose a significant challenge when considering them as part of the ten-year company forecast.

Specifically, BESS installations, due to their flexibility and dispatch schedules, have the capability to significantly worsen or improve system conditions. Especially wholesale operating battery systems have a synchronous external trigger event (market pricing) which could turn them on, or off, at the same time causing significant loading issues on the distribution system. Without direct control and monitoring capability, the Company cannot directly consider either scenario for its peak load forecast.

Front-of-the-Meter (FTM) BESS installations are treated as step loads in the ten-year forecast. When interconnecting to the power system, FTM BESS in the Eversource service territory, whether stand-alone or co-sited with solar, are studied under a scheduled dispatch approach if they fall under the standard interconnection process. This means system capacity for import at the BESS site, is "reserved capacity", meaning the Company will hold this capacity available, at all times, for the BESS operation. A BESS installation that has reserved import capacity during peak load hours will therefore show up as a step load at that reserved import capacity level in the forecast. A BESS installation whose schedule such that no capacity is reserved during peak load hours, does not show up in the forecast.

The Company does not make any downward corrections in the forecast for BESS applications, because dispatch to minimize peak load at a site cannot be guaranteed, especially since most installations are looking to participate in New England ISO markets, which will introduce an external trigger event. Customer-owned and controlled BESS, whether stand alone or co-sited, are therefore not considered to be naturally occurring NWA solutions (See Section 9.3.1 for details). Company-owned assets, however, can be deployed by the Company to address a specific load constraint as a utility-owned and controlled NWA solution. These NWA assets are then excluded from market participation and serve as distribution assets with the sole purpose of ensuring reliability of the distribution system.

Behind-the-Meter (BTM) BESS installations are included as part of the Demand Response Programs in the forecast. The significant issue with BTM BESS installations is their spatial diversity, with typically very small amounts found connected to a single distribution asset (such as a feeder or substation). Further complicating the matter is the fact that currently all offered programs have what is considered an “Opt-Out” capability, such that customers may simply decide not to reduce load on a given day. Therefore, the Company does not treat new BTM BESS installations as a firm capacity resource to displace a traditional distribution asset, because the actual performance of the BESS cannot be known.

However, to the extent that existing BTM BESS installations have regularly performed during times coincident with station peak such that they have persistently reduced the historic demand, this effect will be captured in the ten-year forecast as part of the trend component (see Section 5.1.1).

Advanced Forecasting

As part of the MA DPU 20-74 docket the Company was awarded funding to develop Advanced Forecasting Capabilities. The Company deployed the Advanced Forecasting Solutions in 2022 and has been evaluating data and forecasts produced by the tools since late 2022 with the expectation of having them fully operationalized by January 2024. At this point, the Advanced Forecasting Solution would produce the ten–year Company Forecast, as well as the long-term electric demand assessments beyond the ten-year planning horizon.

The Advanced Forecasting Solution deployed by the Company is a spatial load forecasting tool used by electric distribution system planners to predict:

a. How much power must be delivered
b. Where on the grid the power is needed
c. When the power must be supplied

The tools deliver detailed distribution system forecasts and a standardized integrated grid planning process from Distribution to Transmission planning. Hereby, the tool focuses on three key areas as outlined in Table 32.

Table 32: Forecast Factors Affecting Future Grid Stability

Forecast Factor	Description
Weather Scenarios	Percentile-based base load profiles generated by a temperature-load algorithm (90/10, 50/50, etc.)
Economic Growth	Base load growth using ten-year compound annual growth rate (CAGR)
DER Penetration	(EV, PV, heat pumps, battery storage, energy efficiency, etc.)

Eversource understands growth and change in nodal load pockets through use of the advanced forecast. This allows Eversource to optimize infrastructure investments, manage substation capacity, refine corporate planning initiatives, and increase grid reliability.

The Advanced Forecasting Solution as it is deployed today has two primary functions (modes): Base Load Evaluation and Spatial Allocation.

<u>Base Load Evaluation (base load profiles, data cleaning, weather normalization)</u>

As part of the base load evaluation process PI SCADA data[115] is ingested into the solution and a typical base load shape (as a yearly, hour-by-hour, profile) created. This happens through a variety of steps:

1. Raw PI SCADA data is ingested into the system and cleaned for any faulty measurements, abnormal operating conditions such as switching operations, or significant outages. This is achieved through the creation of a weather correlation function for the load. This allows the solution to remove outliers and smooth temporary transfer drops. The solution also cleans the received SCADA data for historic distributed generation (solar PV) to ensure the load models ingested into the forecast are gross loads.
2. Using 30 years of historic weather data, weather pattern analysis is performed which allows the creation of 90/10 weather scenarios. Using the last years cleaned SCADA data, the solution correlates load behavior to the weather patterns. The weather data is sourced from three weather stations across the state of Massachusetts (KCEF, KWOD, KFMH) and is available as temperature or heat index. The output is three TLY 8760 (Typical Load Year with 8760 hours) base load profiles generated for the 90th, 50th, and 10th percentiles based off the 30-year simulated load profile:
    a) Extreme (90th percentile)
    b) Typical (50th percentile)

115 The PI System from OSIsoft is a suite of software products that are used for data collection, analysis, delivery, and visualization. Supervisory Control and Data Acquisition (SCADA) systems are used for controlling, monitoring, and analyzing industrial devices and processes. The data collected from these devices are streamed into the system for monitoring and further analysis.

c) Low (10^{th} percentile)

3. The Solution then generates weather normalized TLY 8760 load profiles down to the circuit level. It also enables the Company to include climate change forecasts into the load assumptions.

The chart in Figure 80 below shows a sample result of a SCADA cleanup effort conducted by the Advanced Forecasting Solution with Figure 81 showing results of the TLY for the Extreme, Typical, and Low scenario. This allows the Company to understand, in detail, how a reported peak would relate to historic, or forecasted, weather conditions. E.g., a peak in a specific year that was recorded by the Company might have not happened during a high temperature as only relative low temperatures were recorded, or the highest temperatures were recorded on a holiday or weekend. Such a "lower recording" needs to be corrected for the prevailing temperature conditions at the time.

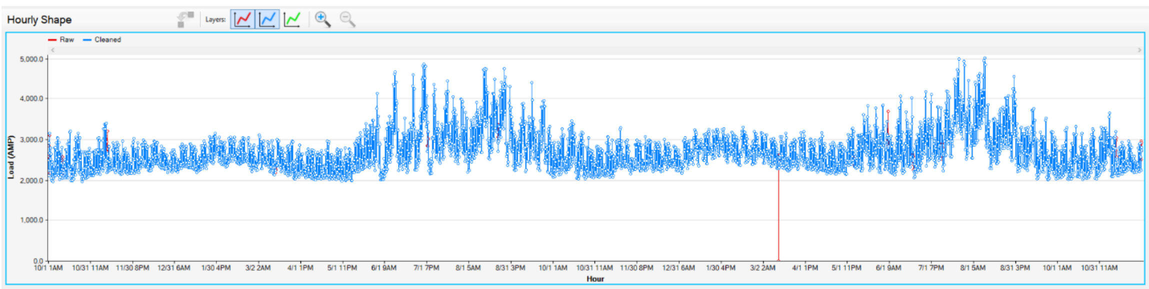


Figure 80: Cleaned Hourly Load Data (blue) with outliers removed (red)

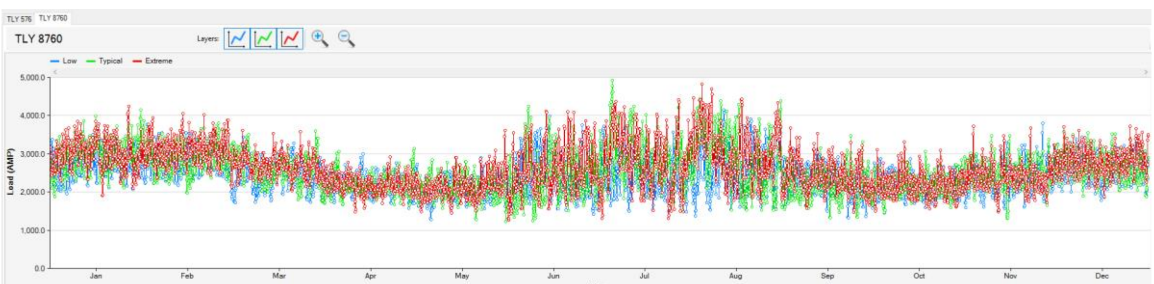


Figure 81: TLY 8760 Graph Output Displaying Low (blue), Typical (green), and Extreme (red)

<u>Spatial Allocation (load forecasting)</u>

The Company has deployed a spatial allocation forecasting methodology that allows it to understand in detail where and when load materializes based on certain external input parameters (such as state objectives) as well as customer socioeconomics. Aside from yielding detailed load growth understandings, the Company is also working on creating scenarios with the ability to evaluate different targeted policies.

The Spatial Allocation mode is responsible for simulating adoption of future load components (EV, PV, heat pumps, base load growth) and allocating system-level load forecasts down to the circuit-level. During Spatial Allocation simulations, load is allocated to map points based on the customer class and guarantee file chosen during initial configuration. The map in Figure 82 shows aggregations of future and existing map points in the Boston Metropolitan Area.

Analysis using GIS data determines the amount of technical potential available on each potential site or map point. Additional data are utilized to help identify services needed at a map point that can be used towards spatial allocations and forecasts. Table 33, shown below, summarizes the factors affecting site selection for each customer class. Future customer service points are created through a combination of heuristic modeling and trained machine learning models. Several machine learning models are trained on nationwide parcel-level data, as well as specific data points available in each state. To predict using these models, features are engineered on parcel, building, census tract, county, and state level data and assigned to each land parcel within a state.

Table 33: Advanced Forecasting Solution Future Site Selection Factors for Load Location Types

Site Type	Site Selection Factors
Shopping Centers	Locations based on Spatial Data Warehouse of Shopping Centers in the service territory based on a mix of third-party data.
Activity Destinations	Locations based on Spatial Data Warehouse of Activity Destinations in service territory based on a mix of third-party data
Workplace	Locations based on Spatial Data Warehouse of Workplace locations in service territory based on a mix of third-party data
Transportation Depot	Locations based on Spatial Data Warehouse of Transportation Depot locations in service territory based on a mix of third-party data
Parking Lots	Locations based on Spatial Data Warehouse of Parking Lot locations in service territory based on a mix of third-party data
EV Public DCFC	Future potential of public DC Fast Chargers based on NREL and purchased EV charge site data
EV Workplace L2	Future potential of workplace level 2 chargers NREL and purchased EV charge site data
EV Public L2	Future potential of public level 2 chargers based on NREL and purchased EV charge site data
EV Residential L1	Future potential of residential EV level 1 charging at points in the existing customer portfolio based on software models
EV Residential L2	Future potential of residential EV level 2 charging at points in the existing customer portfolio based on software models
Rooftop PV	Future potential of residential Solar PV at points in the existing customer portfolio based on software models and data from third-party
Utility Scale PV	Standalone point and service of potential future utility scale solar installations based on software models
Heat Pump	Services placed on both existing and future residential and commercial points

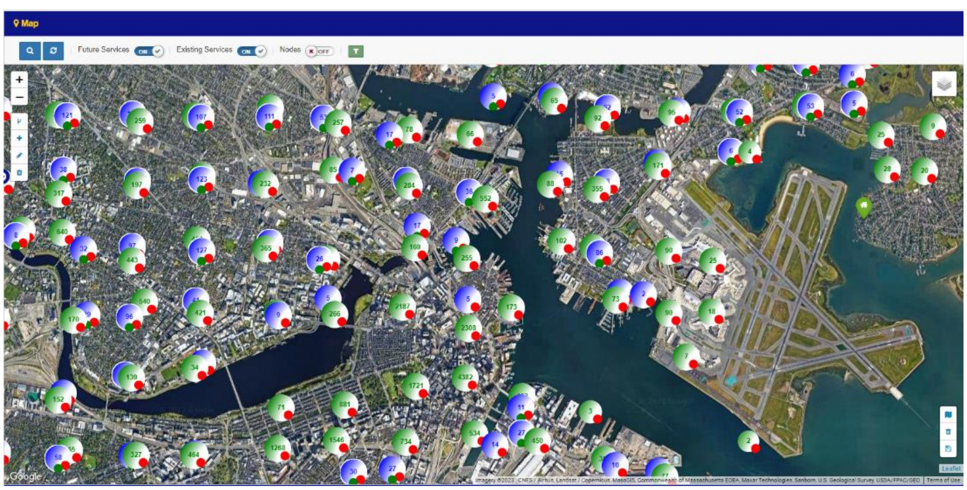


Figure 82: Advanced Forecasting Solution Map Displaying All Existing (blue) and Future (green) Map Points in Metro Boston Area

The Advanced Forecasting Solution utilizes agent simulation, which applies machine learning to geospatial information (housing characteristics, commuting patterns, accessibility to roads, customer energy consumption patterns, human behaviors) to develop a geospatial DER adoption probability model and assign a propensity to each technical site. The factors affecting the propensity model are shown below in Table 34.

Table 34: Propensity Model Factors for DER Types

Site Type	Propensity Model Factors
PV	➢ Model utilizes multivariate machine learning with multiple inputs per parcel evaluated. ➢ Model inputs include land value, political lean of the region, and existing PV adoption
EV	➢ Model contains inputs such as zip-code level traffic flow patterns from third party vehicle mobility data, and the number of existing EV charging stations. However, if policy changes drive EV charging stations in specific communities, such adoption propensity models can be adjusted to reflect those changes and associated impacts on geo-spatial changes in EV deployments – which in turn can inform distribution system plans in those specific areas.
Heat Pump	➢ Model is based on factors such as income, building square feet, and policy allowances. However, if policy changes drive adoption toward specific customer segments, such adoption propensity models can be adjusted to reflect those changes and associated impacts on geo-spatial changes in heat pump deployments – which in turn can inform distribution system plans in those specific areas”
New Growth	➢ Model is based on factors like parcel improvement value, distance to a highway exit, and improvement value ratio compared to other nearby parcels

GPS tracking data was utilized to build out a feature set that enabled a view into travel magnitudes, trip lengths, and frequencies. These features were organized into predictive values and correlated with EV charger locations in MA, and then the top variables were chosen to be fed into a machine learning model.

After integrating all relevant distribution network data sources, summarized in Table 35, the data is utilized throughout every aspect of the Load Advanced Forecasting Solution simulation workflow.

Table 35: Advanced Forecasting Solution Data Inputs

Data Type	Description
PI SCADA data	➢ Used for hourly base load shapes of substations, transformers, and circuits. ➢ PI data is automatically updated and refreshed monthly.
Solar Generation Modeling Data	➢ Using historic Irradiance values and the installed solar data base of the company PV generation is backed out when generating gross load shapes
Weather data	➢ Hourly temperature and heat index data from weather stations is used to generate weather normalized base load shapes ➢ Multiple base load shapes are generated for percentile-based weather intensity scenarios (low, typical, extreme)
Geo-spatial (GIS) data	➢ Geo-spatial (GIS) data is used to create layers of the built-in map in the Advanced Forecasting Solution. Layers include territories of the distribution network hierarchy (substation, transformer, circuit), as well as parcel data for map points (residential, commercial, industrial)
Vehicle mobility data	➢ Data contains zip-code level traffic flow patterns which are used in the propensity model for EV adoption

One important input for the spatial load allocation simulations are technology adoption files[116]. The adoption files contain state-wide projections for each technology (EV, PV, heat pump, etc.) broken down by annual adoption, either in additional kW generation (PV) or by unit additions (number of EV chargers, heat pumps). These projections come from trend models or data supporting reports such as the 2050 Decarbonization Roadmap or DPU 20-80 Future of Gas study.

Hourly (8760) normalized load shapes can be imported for each customer class (EV Residential L1, Rooftop PV Commercial, etc.). Multiple load shapes can be imported for a single DER type and turned on or off depending on the specific forecast scenario being simulated. The figure below shows an hourly load shape used for heat pump forecasts.

[116] Also referred to as "guarantee" files because they ensure the adoption assumed occurs in the simulation in a certain time period.

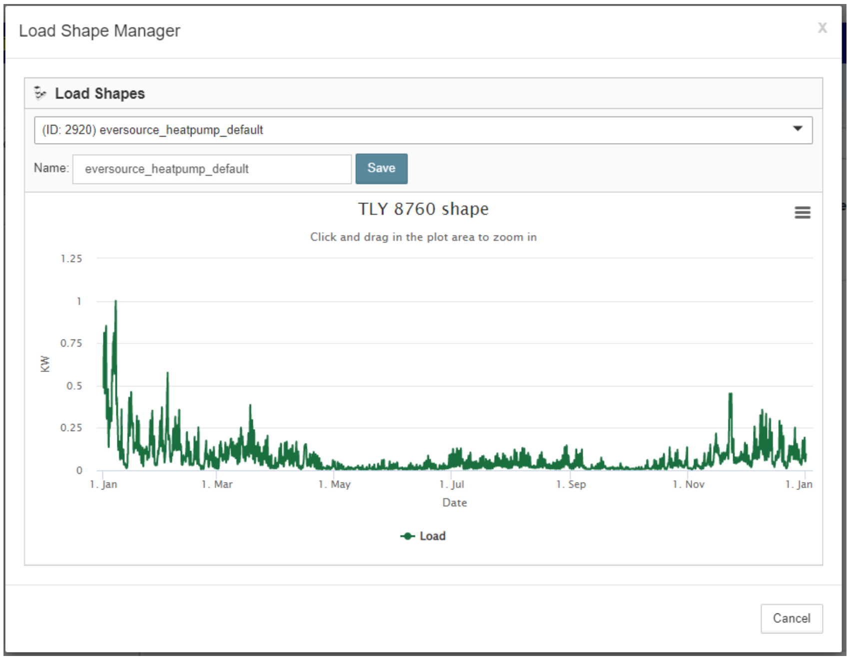


Figure 83: Advanced Forecasting Solution Hourly Load Shape for Heat Pumps

Step loads can be imported into Advanced Forecasting Solution via map points and placed at the circuit-level. Once imported into the map, as shown in Figure 84 below, each step load point is locked as a forecast adjustment to guarantee adoption (excluded from spatial allocation simulation). The map can serve as a live, visual tracker of step loads across service territory. For details on how the Company manages and tracks step loads, see Section 5.1.1.5

Step load map point specifications:

a. Load per Unit (kW)
b. Number of Units
c. Latitude and Longitude
d. Service Start Date
e. Load increments across multiple years
f. Parent node (circuit)

Importing new step loads can be done in bulk at once or done individually via the built-in user interface in the map.

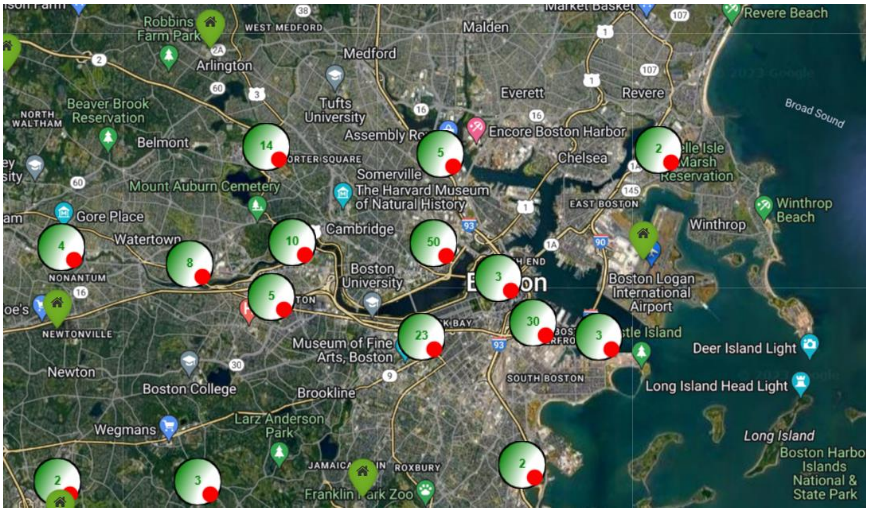


Figure 84: Map Displaying Step Load Points in Metro Boston Area

Once multiple SCADA clean up and Spatial Allocation runs are completed for all substations and technology classes (EV, PV, heat pump, etc.) respectively, the results from each run are layered on top of the TLY 8760 base load profile to create an hourly forecasted load profile for every year projected during the simulation (e.g., 2023-2050) as shown in Figure 85 below. Forecasted hourly (8760) load profiles can be generated for all levels of distribution network (substation, transformer, circuit) and are broken down by load/generation component (base load, EV, PV, heat pump, etc.) Forecasts address both short-term (hourly) circuit trends and long-term grid expansion (up to 2050).

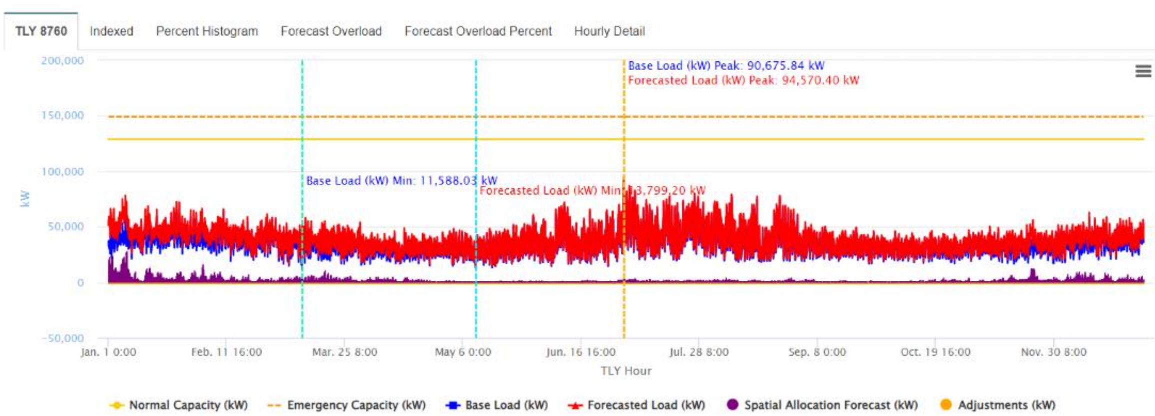


Figure 85: TLY 8760 Forecasted Load Profile Displaying Base Load (blue), Spatial Allocation Forecast (purple), and Total Forecasted Load (red)

Additional graphs are generated such as monthly and seasonal peak changes and capacity overload percentages shown below in Figure 86 and Figure 87 respectively. These results can help system planners more efficiently plan substation capacity upgrades as well as geo-targeted peak demand management. But in order to effectuate those outcomes, policy changes may be necessary in the current construct of Demand Response programs. Further explanation on applicability of Demand Response programs in a decarbonized heat pump driven electrification future is included in Section 8 and 9.

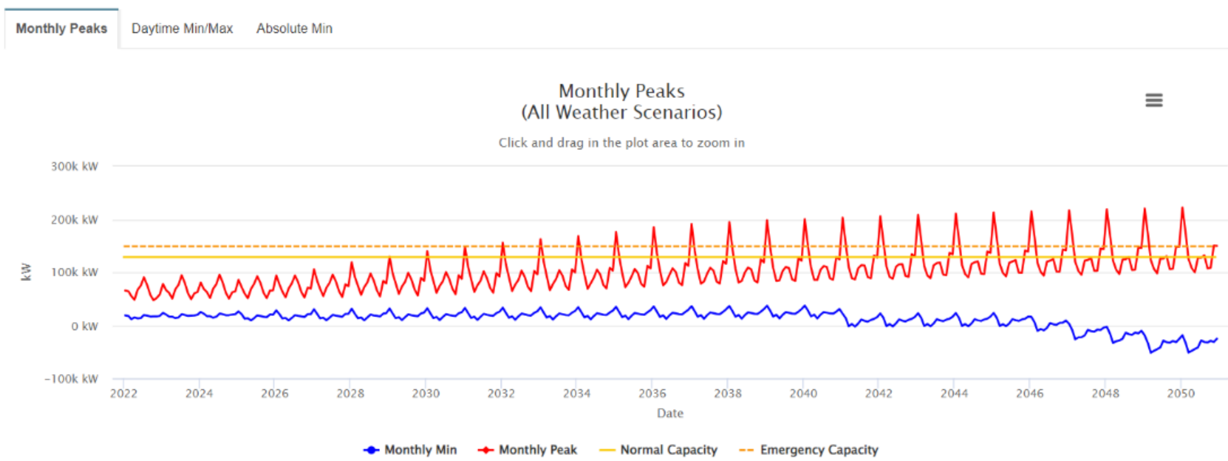


Figure 86: Monthly Peaks Graph Displaying Monthly Peak (red), Monthly Min (blue), and Station Capacity (yellow)

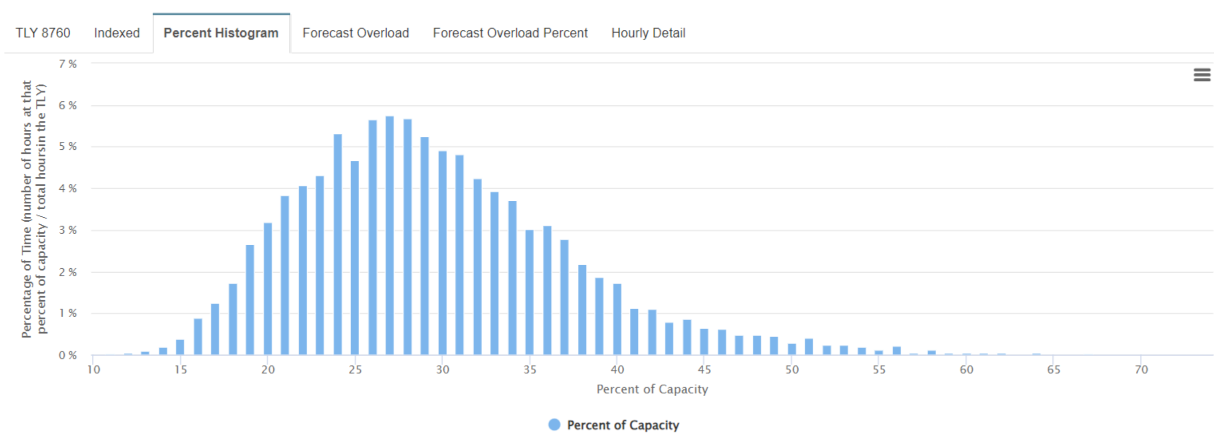


Figure 87: Capacity Overload Percent Histogram

5.1. Five- and Ten-Year Electric Demand Forecast at the EDC Territory Level

The Company's Territory and following Sub-Region level forecasts demonstrate that a transition point in the makeup of electric demand growth is rapidly approaching. Over the next 5 years, especially in the Metro Sub-Regions, new business growth is driving load up through large step loads. Meanwhile, electric vehicles are growing exponentially across the system, and by the end of the decade will start to impact the overall system load more profoundly than any other load component. And lastly, just beyond the 10 – year horizon the shift to a winter peak awaits as electric heating rapidly evolves, buffered by a still lower winter peak in 2023. As soon as the system transitions to a winter peak however, both EV and heating will drive load to an extend not before seen and decisions made today will determine the readiness of the system when that happens.

5.1.1. Aggregate Demand – Summer and Winter (Total)

In aggregate the 21 Bulk substations in Metro Boston, 23 Bulk substations in Metro West, 28 Bulk substations in Western MA, 29 Bulk substations in Southeastern MA have total firm capacity of 3.0 GW, 2.2 GW, 1.3 GW and 1.4 GW respectively.

These Bulk substations serve current peak demand of 2.2 GW in Metro Boston, 1.8 GW in Metro West, 0.9 GW in Western MA and 1.2 GW in Southeastern MA Thus, in aggregate, within these regions, there's a current available headroom of 1.0 GWs in Metro Boston, 0.3 GWs in Metro West, 0.4 GWs in Western MA and 0.2 GWs in Southeastern MA

Over the next decade – by 2033, the electric demand is expected to grow to 2.9 GWs in Metro Boston, 2.1 GWs in Metro West, 1.0 GWs in Western MA, 1.4 GWs in Southeastern MA

Thus, in aggregate, within these regions, by 2033, the projected available headroom[117] will be 1.2 GWs in Metro Boston, 0.8 GWs in Metro West, 1.2 GWs in Western MA and 0.7 GWs in Southeastern MA

See the following Table summarizing the data, including a preview of the in Section 8 discussed long term impacts and how they relate to the available capacity.

[117] 2023 Headroom numbers include projects that are expected to be in service prior to 2033, as discussed in Section 4 (4.3.7, 4.4.7, 4.5.8, and 4.6.7) and Section 6 (6.5, 6.6, 6.7, and 6.8).

Table 36: Projected Headroom

(GW)	Metro	Metro W	SEMA	WMA
Installed	3	2.2	1.4	1.3
2033 Peak	2.9	2.1	1.4	1
2035 Installed Capacity	4.1	2.9	2.1	2.2
Headroom 2033	1.2	0.8	0.7	1.2

While, as noted previously, Bulk substations are planned to serve specific townships, these significant deficits aren't directly applicable, in aggregate, they highlight the challenges EDCs have to overcome to continue to maintain reliability. Throughout the Eversource service territory, this demand is expected to go from 6,126 MVA in 2023 to 7,369 MVA in 2033. This increase to 120% of today's values is driven predominantly through the addition of new loads in the state. Figure 18 shows the aggregated station forecasts for the Eversource Service Territory in Massachusetts. There are two trends observable in this data. In the first 5 years, Eversource see a significant uptake of the load due to significant regional additions of new step loads (see specifically Section 5.2 for the Metro Boston Sub-Region and its step loads). This results in a short-term jump of the aggregated station peak by 2027. This increase however is, as discussed by sub-region, very locational and some regions see significant more load update than others. Towards the end of the forecast, much of the impact is driven by electric vehicles which grows exponentially over 10 years to outgrow step load impacts after 2031 (a fact that is magnified by the fact that there is no step load information past 2028).

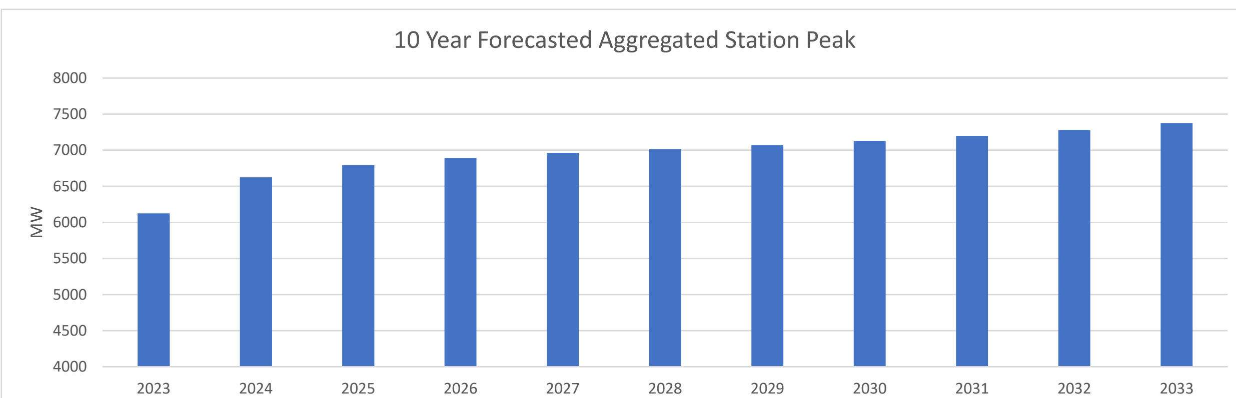


Figure 88: Summer Statewide Aggregated Demand

5.1.2. Weather Normalized Econometric Forecast (Trend)

The Company's statewide trend forecast shows a compound annual growth rate (CAGR) of 0.4% on the underlying load on the system. As discussed in Section 5.1.1, this load growth represents the econometric trend model which is inclusive of naturally occurring EE and the impacts DR and BTM storage has on the station peaks.

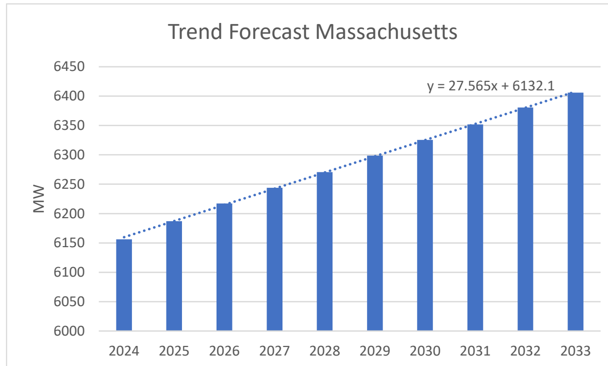


Figure 89: Development of the underlying Trend Load

Detailed economic future trends are outlined by each section in Section 5.2.2, 5.3.2, 5.4.2, 5.5.2 where regional economic developments and their impacts on the trend load are discussed. Overall, the growth of the Trend load represents 4.6% relative to the 2023 peak.

5.1.3. Electric Vehicles

The Company expects that electric vehicle adoption will grow exponentially until the end of the decade at which time saturation effects limit the growth rate. The growth rate then enters logistic growth model with limitations on vehicles sold and turnaround times of the market. Towards the end of the long-term projections, growth will shallow out as late adopters electrify. Figure shows the vehicle stock with percentage EVs for the entire state used as an underlying model. By 2033 the Company expects that 29.2% of light duty vehicles (LDV) in the statewide market will have been replaced by electric vehicles.

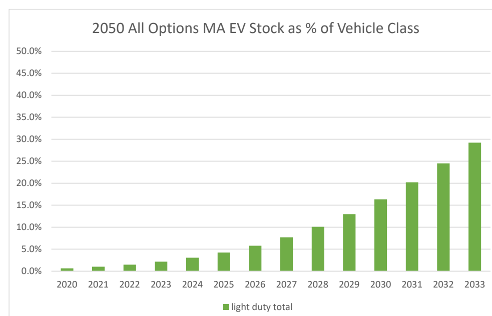


Figure 90: State-Wide LDV EV growth Model (All Options)

Figure 91 shows the expected impact on the aggregated substation peak of LDVs in the system. This information does not include expected step loads (See Section 8.3) from electrified fleets and deports that depend on electrification from medium duty (MDV) and heavy-duty vehicles (HDV) as the Company does not have sufficient certainty to allocate these loads to specific substations. This represents a significant (>9% from 2023) new load addition to the system and already includes the

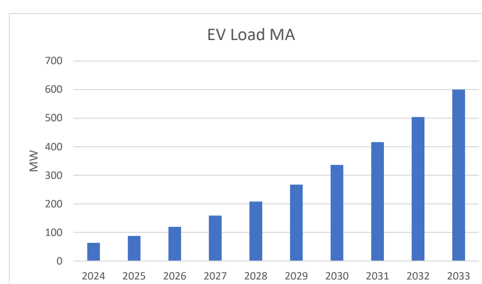


Figure 91: Expected EV Impact on Peak Load

assumption of extensive charge at work capabilities being deployed and an equal distribution of charging activities. If insufficient charge at work is incentivized, load in the evening would increase, contributing to the peak. It also only represents the LDV charging impacts.

If the All Options ramp up of MDV and HDVs is assumed, by 2033 an additional 136 MW and 86 MW respectively is expected to be added throughout the system with Table 10 below detailing the expected, by region split.

Sub-Region	Metro	Metro West	Southern	WMA
MDV (MW)	17.6	36.9	43.5	37.9
HDV (MW)	8.1	23.2	11.8	42.6

Table 37: MDV and HDV split by Sub-Region

Throughout the state, the Company is observing varying travel patterns between the different sub-regions, each of which is highlighted in the Sections 5.2.3. Overall, there are typically two impact scenarios, the morning peak, coinciding with the arrival at work locations, as well as the evening peak, representing returns from commutes. Figure 92 shows the overall trip termination profile of light duty vehicle trips in Massachusetts. The first peak is visible from 7:45 am to 9:45 am, with the second peak at 5:45 pm. Of note is that fact that these arrival profiles do not directly constitute charging profiles. Not every vehicle will be plugging in at every stop, and not every vehicle will charge every day. The expected charging peak for the long-term models (see Section 8.2) for EVs is expected to occur in the late evening and early morning hours.

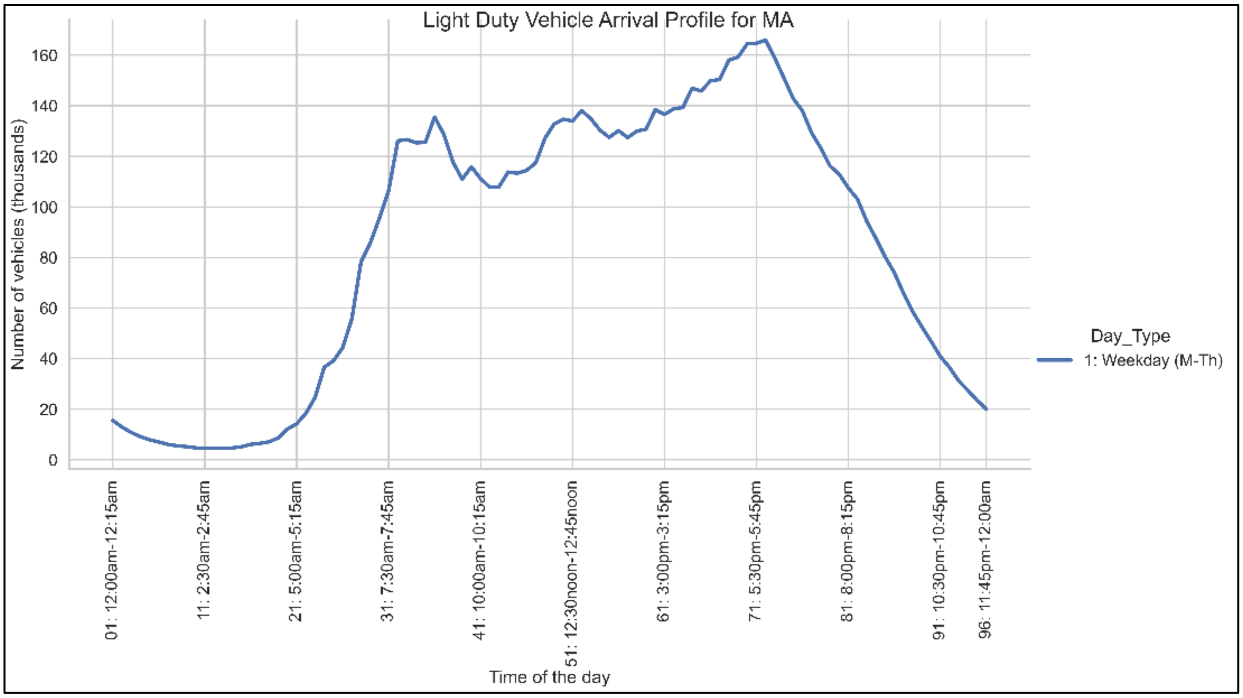


Figure 92: Trips Terminated every 15 minutes in MA.

5.1.4. Large Load (Step/Spot Load)

Step loads across the entire service territory in MA are the single largest load driver and solely responsible for almost all capacity related projects the Company currently has underway. The total system peak is anticipated to increase by 13% due to new step loads over the next 5-years. In the forecast, these known step loads taper off after 5 years, as that is the outer edge of the planning horizon for most developments. Due to the limited visibility and high volatility of development plans the 6th to 10th year will likely see, as time progresses, the addition of new step loads.

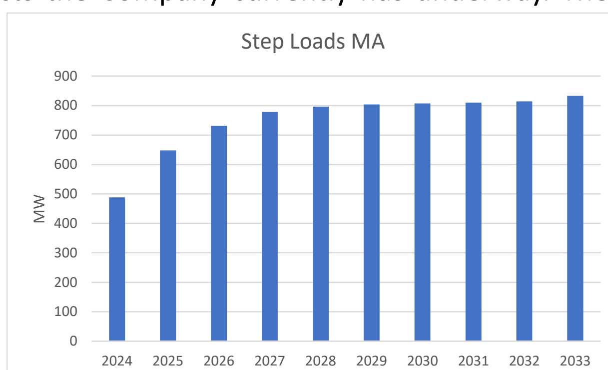


Figure 93: Known Statewide Step Loads

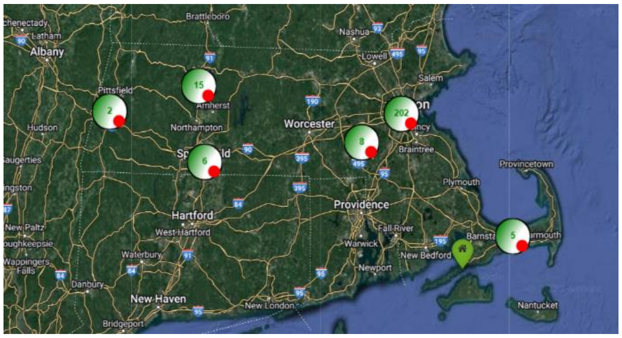


Figure 94: Geographic Locations Step Loads

Most of the step loads registered at a State Level are driven through load additions in the EMA-North Metro Sub-Region where the Company has identified more than 70% of all of the registered step loads causing severe constraints in the region (Details in Section 5.2.3). Most of the step loads currently tracked by the Company are due to the significant boom in the bio-tech industry with almost all additions >95% for the metro region being related to lab space. Overall, the Company is tracking 238 step loads as of this filing with the above-mentioned heavy skewing towards metro regions. Figure shows currently tracked step loads across the state and their regional allocation. Step loads as a whole supply the largest single contribution to the statewide peak increase with a total of 833 MW.

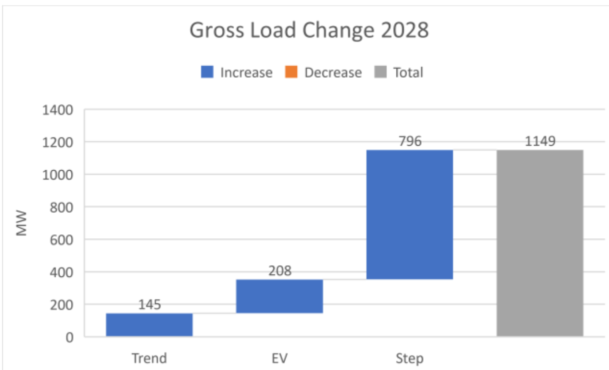


Figure 94: Forecasted Gross Load Change from 2023 to 2028

Figure shows the aggregate forecasted gross load (grey) change across the Company's Massachusetts Territory by 2028. Clearly visible is the fact that Step Loads are the predominant driver on the capacity need over the course of the next 5 years. Over the course of the following 5 years up to 2033, the relative impact of EVs increases as Eversource reaches the end of the exponential impact.

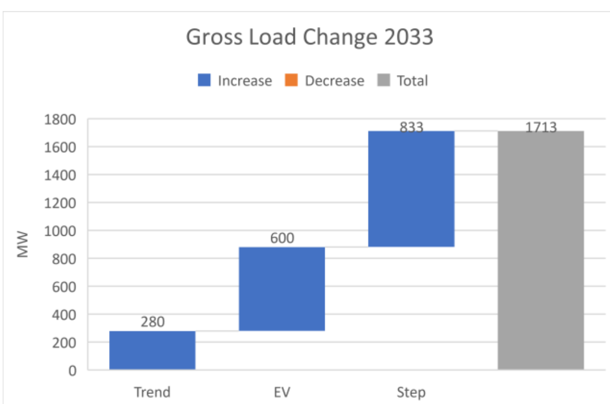


Figure 95: Forecasted Gross Load Change from 2023 to 2033

One of the largest, future expected, step loads will be the MDV and HDV charging depot locations. System wide, based on the Company's mobility data, the total demand for depot charging for MDV and HDV vehicles is shown in Figure 96. In total, the Company is looking at 137 MVA and 101 MVA respectively summer peak contribution, as well 193 MVA and 54 MVA respectively winter peak contribution. As the Company continues to engage and monitor development of charging depots and the adoption of MDV and HDV vehicles updates to the step load trackers will be made.

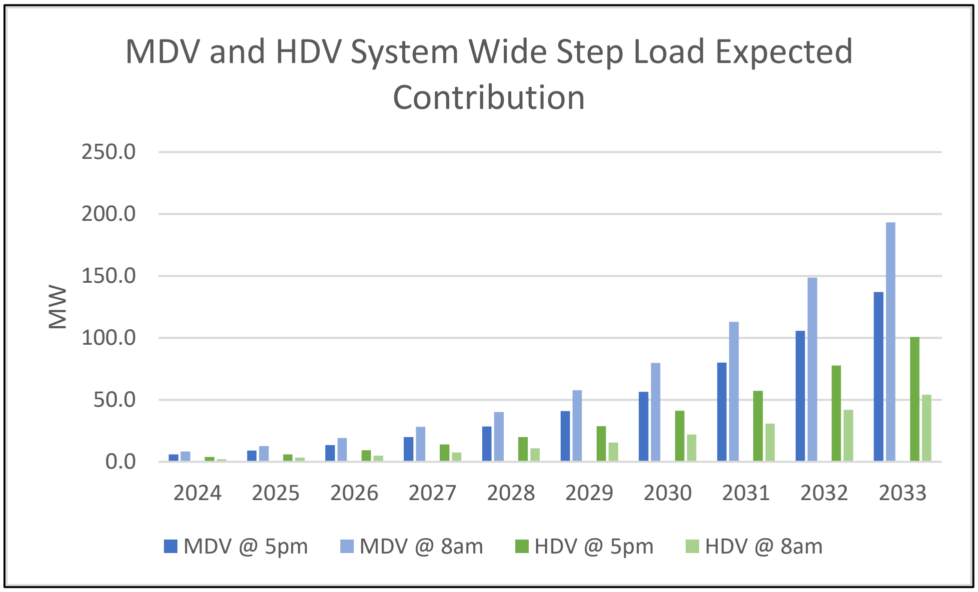


Figure 96: Annual Cumulative System Wide Step Load Contribution

5.1.5. Energy Efficiency

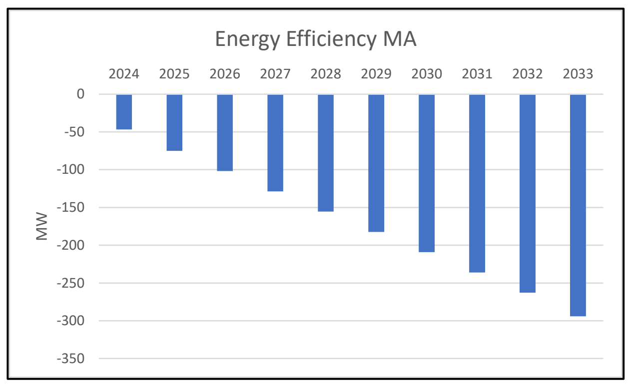


Figure 97: Expected Energy Efficiency Impacts on Overall Territory Peak

Energy Efficiency is one of the two key non-wires alternatives directly considered in the Company's forecast to reduce peak demand and defer system capacity needs.

Over the past decade, energy efficiency has proven to be an exceptionally impactful method for reducing peak system load. Future EE impacts are expected to be lower as some critical savings opportunities, such as lighting, have been addressed (see section 6.1.5). Given continued funding at current levels, the assumption is that the Company run EE programs will continue to have an impact on the overall system peak load, in addition to providing customers with lower annual bills.

For the Mass Save program, the Company assumed that the approved 2024 budget of $525M is constant through the 10-year period. This is a scenario analysis, and does not represent forecasted spend; as those details will be determined in the Three-Year Plan process. Of that spend, approximately $200M was anticipated to be spent on energy efficiency. If the Three-Year Plans were to change, the overall impact of EE on the aggregated statewide station peaks would change.

EE is hereby deferring 294 MVA (or 2 bulk substations equivalent) of capacity needs over the next decade. Importantly to note is that these energy efficiency impacts are of similar magnitude as the Trend growth, therefore offsetting the underlying economic growth of load, but not new additions of EVs or Step Loads.

The savings from the Mass Save active demand response programs (see section 6.1.9) is currently not explicitly included in the Company's forecasts. The Mass Save programs have an "Opt-Out" capability, such that customers may simply decide not to reduce load on a given day. Therefore, the Company does not treat new Active Demand Response program enrollments as a firm capacity resource that could result in the reliable reduction in peak demand necessary to displace a traditional distribution asset, because the actual performance of the customer cannot be ensured.

However, to the extent that existing ADR customers have regularly performed during times coincident with station peak such that they have persistently reduced the historic demand, this effect is captured within the ten-year Company forecast as part of the trend component (see 5.1.1). The Company is also investigating other program designs that could make DR resources more firm.

5.1.6. DER Growth: Solar PV, Battery Storage, Grid Services

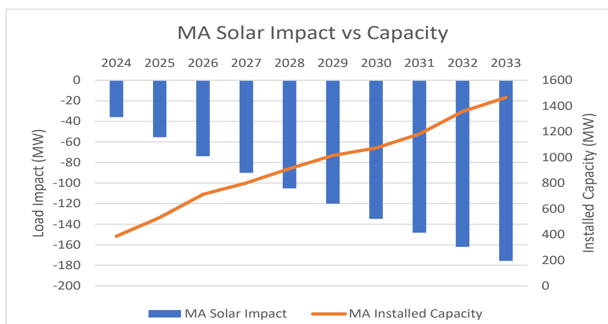


Figure 98: Expected Solar Impacts on Aggregated Station Peak Load and Total Solar Capacity

In addition to Energy Efficiency, distributed generation represents the second largest deferral of capacity needs in the Company's 10-year forecast. While DER growth is expected to continue impacting the overall peak of the system, high adoption rates will slow return of peak deferral, as more solar generation goes online, the net system peak continues shifting to later in the day, decreasing the incremental impact of the next megawatt of installed solar on the actual system peak. Further, adjustments in the output simulation for peak contribution are made to ensure that weather impacts are considered. With more storage systems being proposed for co-sited installations, the evening reach of solar installations is extended which allows the impact to continue carrying later into the evening. Figure represents the impact to the net peak in blue bars, and the corresponding projected installed solar capacity in orange on the secondary axis.

EVERSOURCE

Figure shows the expected ramp up of solar adoption in the state, as outlined by the pathway model and simulated for Eversource territory. The actual projected solar installations, ground mounted and roof top combined is driven by the state's policy objectives and expected to reach 1,600 MW by 2033, incremental to today's installed capacity of 1,176 MW.

The expected overall deferral of infrastructure needs reaches 176 MVA, or about 1 bulk substation. Figure 99 shows the Net Load Change by 2028 and 2033 respectively across the Company's entire service territory in MA.

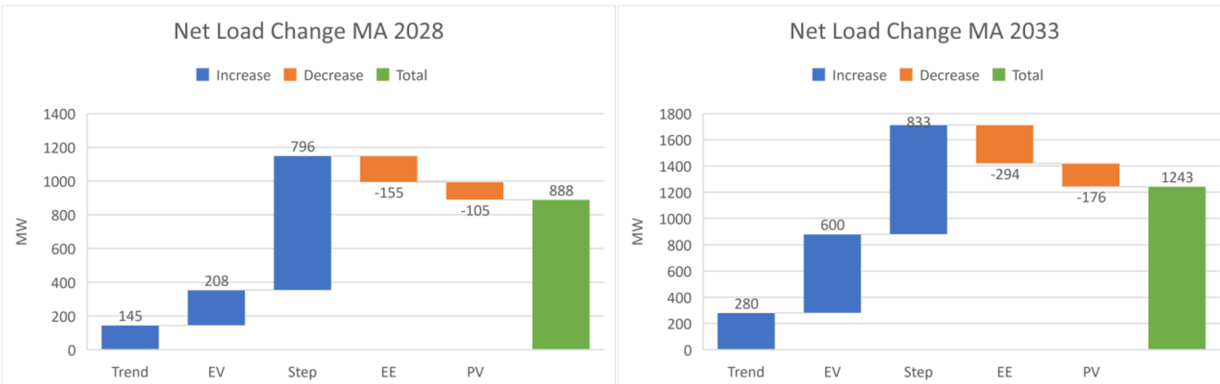


Figure 99: a) Aggregated Net Load Change for MA Territory by 2028 b) Aggregated Net Load Change for MA Territory by 2033

This Net Load Change comes courtesy of almost 30% LDV adoption in the Company's territory as well as all 260 additional new developments in the state. In the shadow of this development, a staggering 1.96 GW of heating electrification load is expected to martialize during winter morning hours representing a 20% conversion of space heating, a development that will, in short time, overtake the summer peak and cause an explosion of peak demand across the service territory. In the meantime, the incremental 1,600 MW of solar have an ever-fading impact on the peak as it shifts more and more to the evening hours, resulting in only 176 MW of deferral.

5.1.7. Heat Electrification

Overall, the All Options Scenario will yield a 3.4 GW winter peak addition of heating load by the Winter of 2035. This load addition is the equivalent of 1.3 billion square feet of space heated electrically through ASHPs under the assumption of a coefficient of performance[118], (COP See Section 8.1 for details) of 2, or the equivalent of close to 654,00 residential homes.

[118] The coefficient of performance (COP) is an expression of the efficiency of a heat pump and the ratio of energy required to useful cooling or heating

743,000 residential heat pumps as well as 371 million sq-ft of commercial space electrified. With an average of 5kW per residential heat pump and 2.52W/sq-ft for the commercial space, a total of 4.6 GW, 3.7 GW and 0.9 GW respectively, peak heating load is expected by 2035. This combined peak of 4.6 GW of heating load is split at 74.2% towards Eversource based on the total building sq-ft in the Company's territory vs that of the other EDCs to yield 3.4 GW of total heating peak contribution. The coincident peak of the system is expected to occur at 9 am and reach 8.4 GW total as shown in Figure 100. The solar reduction at this point drops at a statewide level with the peak now occurring during winter mornings, resulting in a lower firm capacity being attributed. With the change to the long-term demand assessment model, the Company also includes HDV and MDV in the data, which causes an increase on the EV component while the base component is reduced due to the early winter morning time, where base load is significantly lower than during the summer.

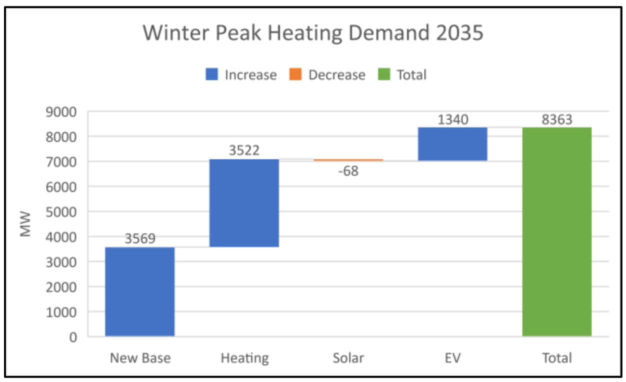


Figure 100: 2035 MA Winter Peak Make Up

The Company is expecting to transition to a winter peak no later than 2035.

5.1.8. Summary

With more than three quarters of a gigawatt of certain and probable step loads (see Section 5.1.1.5) expected over the next five years, it must also be assumed that further additions can be expected in the five- to ten-year horizon, especially with the rapid increase in fleet electrification.

Overall, as demonstrated above, the electrification goals of the Commonwealth drive a generational increase in electric demand – not seen in New England before through the electrification of vehicles. Further, the Company is seeing unprecedented new load growth in the Metro Regions making immediate action by the Company unavoidable. In the meantime, electric heating is ramping up at a staggering rate, which, while still hidden in the winter peak in the next 10 years, show just how much heating electrification will bring to the system, with the incremental heating addition to winter peaks by 2033 totaling 3.57 GW, significantly more than the summer peak additions of 1.3 GW, while only representing just above 38% of the projected final load.

In the current construct, there is a disconnect between the open market approach to building electrification and the necessarily more targeted approach to infrastructure upgrades. Shown below is an analysis of the available electrification hosting capacity at each municipality in Eversource's territory based on the available headroom of the substation they are served by.[119] The Company translates the capacity headroom created by the new and upgraded substations into electrification enabled hosting capacity per capita in each city served by those associated upgrades. This kW/capita changes each year of the ten-year capital plan period as planned upgrades go into service and additional electrification capacity is enabled. The detailed analysis is included in the Appendix. The timing and order of the substation upgrades modeled here reflect the anticipated capacity needs in each region due primarily to economic growth and step loads. As noted above, heating electrification is not anticipated to create a winter peak in any region during the 10-year forecast period. However, if electrification adoption varies from the expectations in the model, certain substations could become winter-peaking earlier than expected and experience capacity deficiencies that weren't modeled. Therefore, it is important to coordinate customer-facing electrification programs with system planning efforts.

This analysis can be further expanded to individual towns and communities served by each substation. These cities, towns and communities can then be classified into multiple tiers based on the amount of available electrification hosting capacity. As town's host new bulk substation infrastructure, they would move up in these Tiers with the highest per capita available electrification hosting capacity. To the extent, the commonwealth's clean energy programs are then associated with these highest Tier cities and towns, the commonwealth's clean energy programs can be directly connected with the grid capacity – with direct benefits directed to the communities that host the new infrastructure.

[119] Headroom is calculated by equally splitting substation capacity between cities they serve. Distribution systems do allow local re-arrangements that make these numbers only indicative and subject to change.

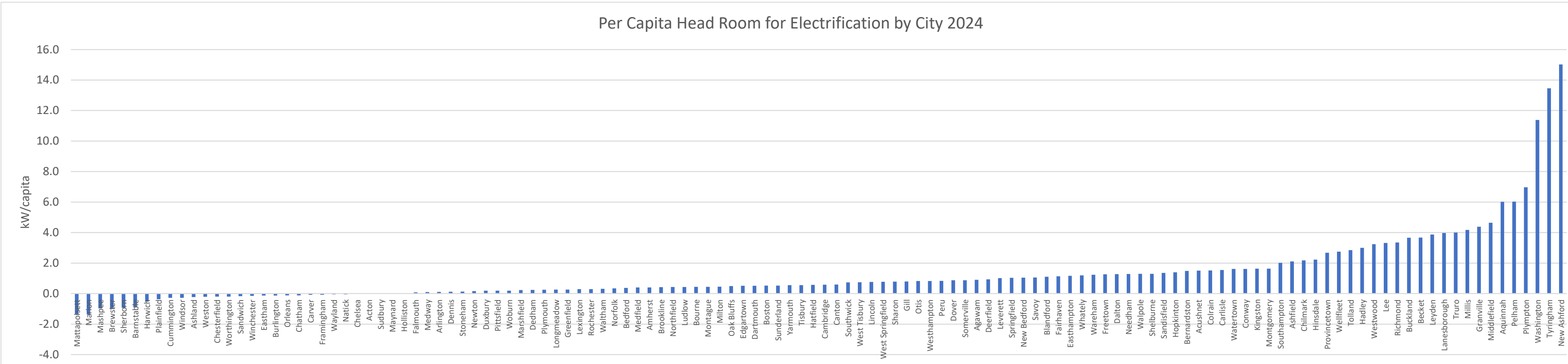


Figure 101: Available Summer Headroom by Sub-Region 2023

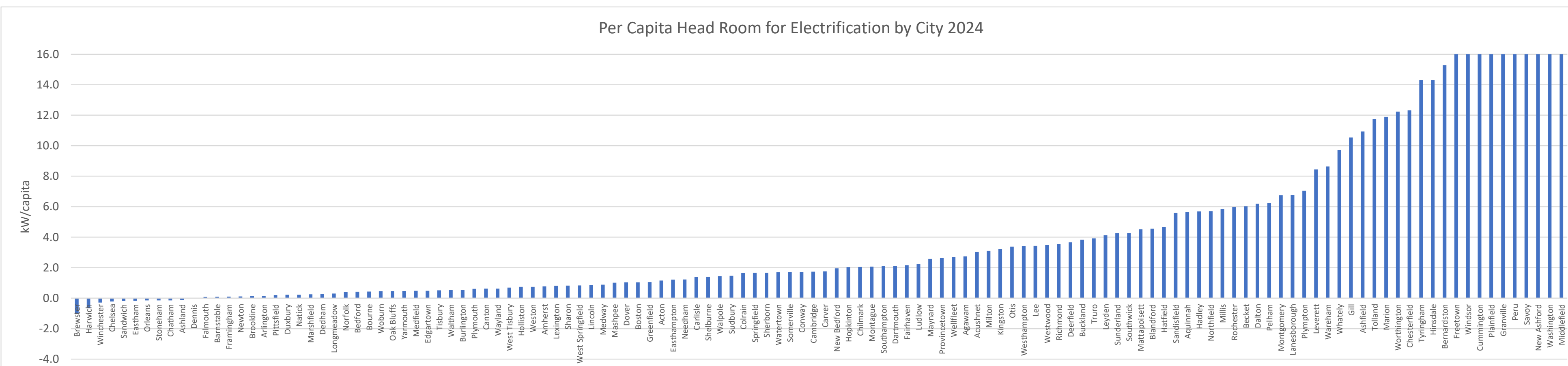


Figure 102: Available Summer Headroom by Sub-Region 2033

5.2. EMA-North Metro Boston Sub-Region

The EMA-North Metro Sub-Region's forecast over the next decade is predominantly shaped by the significant growth of industry in the region. With bio – tech driving the largest portion of these step loads through the development of new labs, the Metro Sub-Region is seeing a 27% projected load increase just through new businesses from its 2023 peak over the next 5 years. In addition, electric vehicles are picking up and solar has very little impact, due to limited space, to curtail any peaks. The regions itself presents the largest load development in the Company's territory and will require immediate action to ensure sufficient capacity is available over the course of the next decade.

5.2.1. Aggregate Demand – Summer and Winter

Over the next decade the electric demand for the summer (design peak) in the EMA-North Metro Boston Sub-Region is expected to go from 2208 MVA in 2023 to 2944 MVA in 2033, relative to a currently installed bulk capacity of just shy of 3GW. This increase to 133% of today's values is driven predominantly through the addition of new loads in the region. Figure 103 shows the aggregated station forecasts for the Metro Boston Sub - Region. There are two trends observable in this data. In the first 5 years, Eversource sees a significant uptake of the load due to significant regional additions of new step loads. This results in a short-term jump of the aggregated station peak to 128% by 2028. This increase however is, as discussed by sub-region, very locational. Towards the end of the forecast, the majority of the impact is driven by electric vehicles that, while expanding exponentially throughout the 10 years, outgrow step load impacts after 2031 (a fact that is magnified by the fact that there is no step load information past 2028).

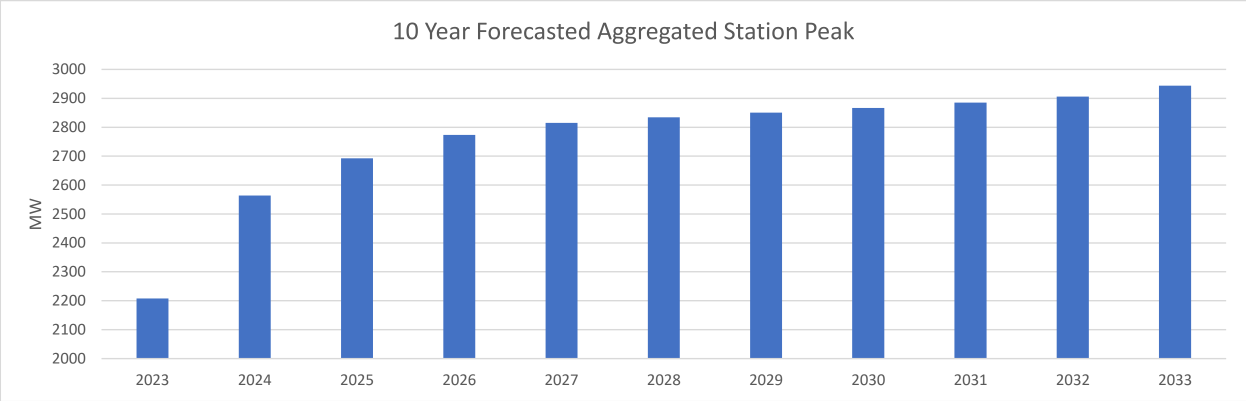


Figure 103: Summer EMA-North Metro Sub-Region Aggregated Demand

5.2.2. Weather Normalized Econometric Forecast

As discussed earlier, in Section 4.3.3, Eastern Massachusetts (North) Gross Metropolitan Product (GMP) has displayed strong growth over the last five years and is anticipated to continue this impressive growth in the coming years. Real household income in this region is high and growing remarkably compared to other Massachusetts regions, which are forecasted to grow at a slower pace. This increase in real household income is expected to continue into the late 2020s. Total employment and unemployment rates are forecasted to stay relatively stable after making a full recovery to pre-pandemic levels. Finally, housing is forecasted to decline after 2023 as rising interest rates make mortgages less affordable. Table 11 summarizes key economic forecast trends for the EMA North region, encompassing both the Metro East and Metro West subregions.

Table 38: Key Economic Variables for the EMA North Region

Eastern MA North Economic Statistics*					
	Gross Metro Product	Real Household Income	Total Employment	Unemployment Rate	Housing Starts
2019	194	186,267	1,298	2.8	4,971
2020	188	198,357	1,185	9.7	5,296
2021	200	207,679	1,230	5.5	7,058
2022	205	201,581	1,283	3.6	7,225
2023	211	208,637	1,319	3.2	5,230
2024	*215*	*215,325*	*1,332*	*3.2*	*5,887*
2025	*220*	*221,044*	*1,344*	*3.3*	*5,965*
2026	*227*	*227,428*	*1,353*	*3.3*	*5,882*
2027	*233*	*234,031*	*1,358*	*3.3*	*5,582*
2028	*238*	*240,288*	*1,362*	*3.3*	*5,387*
CAGR '19-'23	1.7%	2.3%	0.3%	2.7%	1.0%
CAGR '24-'28	*2.1%*	*2.2%*	*0.5%*	*0.8%*	*-1.8%*
**Source: Moody's Analytics data for Boston, MA*					

Using the weather normalized econometric trend forecast outlined in Section 5.1.1 the expected growth of the existing load is calculated. Figure 104 shows the trend development of the underlying load over the forecast horizon as well as the percentage change from the Base Load. As shown in the figure, the forecasted load increases by 115 MW from 2023 to 2033, based on economic trends alone.

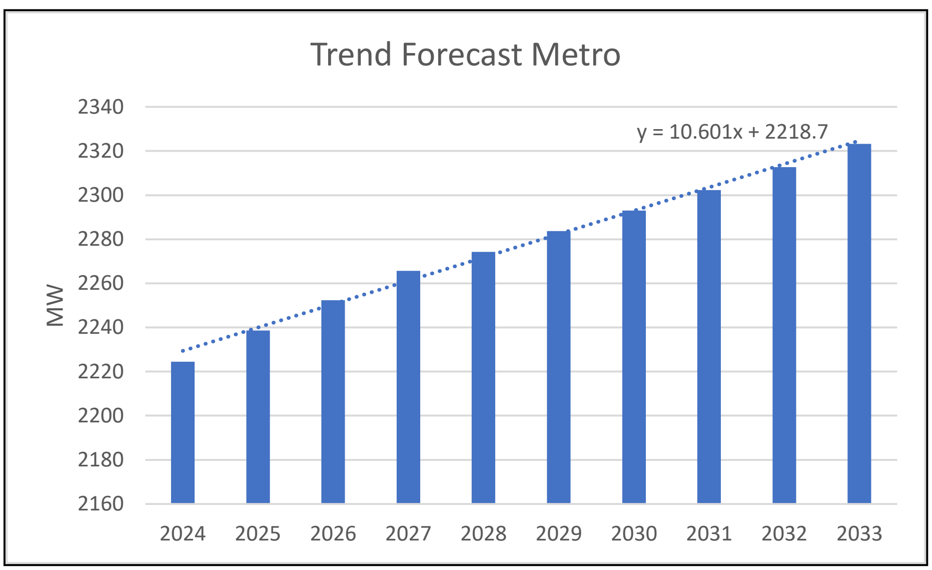


Figure 104: EMA-North Metropolitan Sub-Region Econometric Trend Forecast

5.2.3. Electric Vehicles

Over the next 10 years the Company expects that electric vehicle adoption will grow exponentially. Figure shows the expected impact of EV charging load on the summer peak demand. These numbers reflect only light duty personal use vehicles, not fleet charging, which is captured in the Step Load Tracker. The data shows that EV charging alone will add 130 MW to the forecasted system peak over the planning horizon.

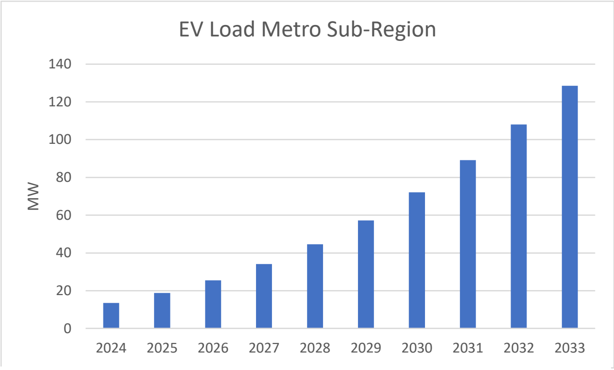


Figure 105: Expected EV Impact on Peak Load EMA – North Metro – East

It should be noted that that value however is not the key driver of EV load in the region as the Company's mobility data shows a significant regional influx of traffic in morning hours as compared to the non-Metro Sub-Regions due to inbound commuter traffic. Figure 106 shows the average trip termination data for the region on a typical summer workday clearly highlighting the early morning peak of traffic.

Overall, LDV EVs are expected to contribute about 130 MW to the 2033 peak of the Metro Boston Sub-Region as shown in Figure .

If step loads for MDV and HDV materialize in the region as supported by their transition in the All Options Pathways, the Company is expecting an additional 17.6 MW and 8.1 MW respectively.

EVERSOURCE

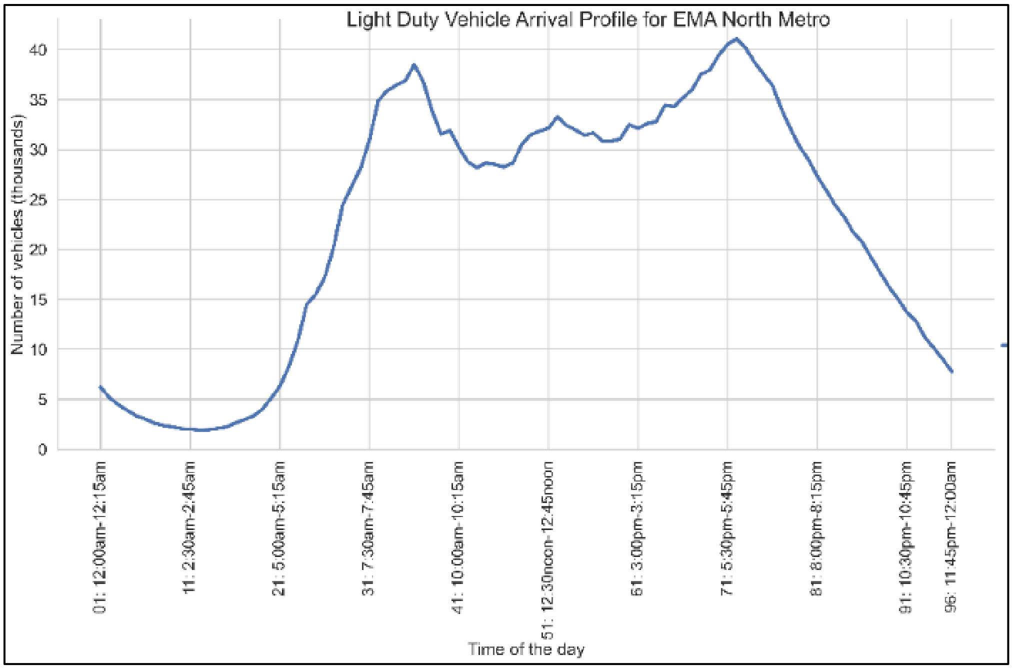


Figure 106: Light Duty Vehicle Arrival Profile for EMA North Metro Region

5.2.4. Large Load (Step/Spot Load)

Step loads constitute the largest driver of electric system demand in the EMA-North Metro Boston Region today. However, due to the planning uncertainty around the step load development outlined in Section 5.1.3.5, the Company typically has limited visibility beyond the five-year horizon. Within this five-year horizon however, 2024-2028, the Company has knowledge of and is expecting more than 570 MW of step loads to come onto the system as shown in Figure . As time horizons draw nearer, the Company expects to update the 2029-2033 data for the step loads.

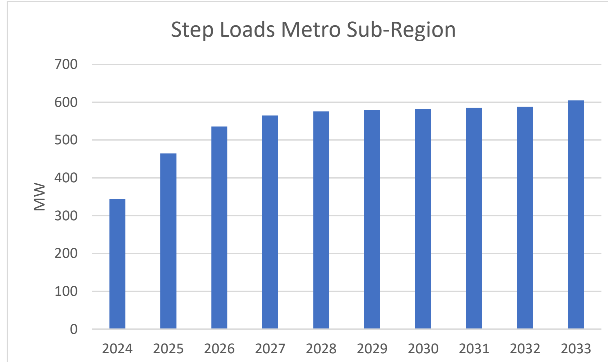


Figure 107: EMA-North Metropolitan Step Load Forecast

Most of the new development by the numbers is hereby happening in the Boston and Cambridge region with the vast majority of the new Step Loads directly or indirectly related to new Bio – Tech Lab investments. Figure shows the regional allocation of step loads in the EMA-North Metro Boston Sub-Region known to the Company. A significant cluster can be observed in the East Cambridge Region, as well as downtown Boston.

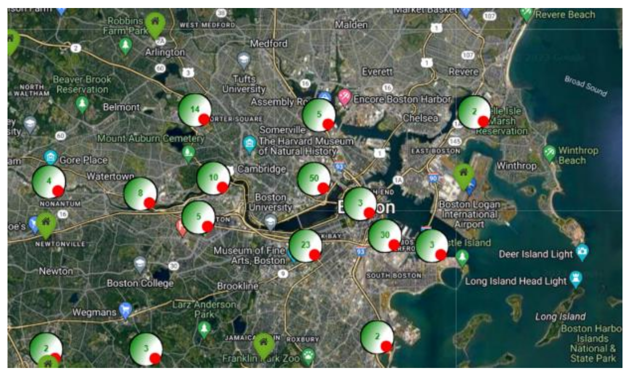
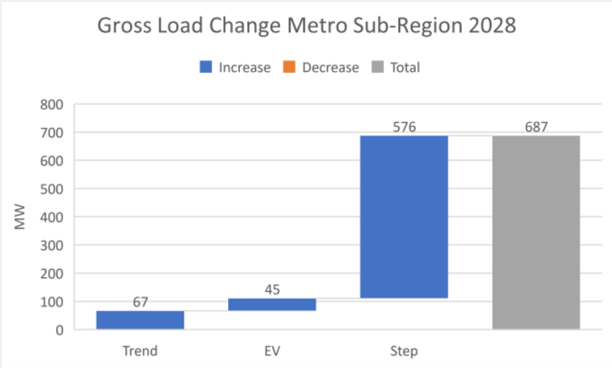


Figure 108: Location and density of Metro Sub-Region Step Loads

With more than a net 600 MW projected increase of due to step loads over the next decade, the region faces unparalleled electric constraints outlined in Section 4 and Section 5. The Step Loads dwarf as shown in Figure 110, especially in the short term, any other load growth impact in the region by multiple factors clearly showing the need for future infrastructure investments in the area to keep up with rising demand.



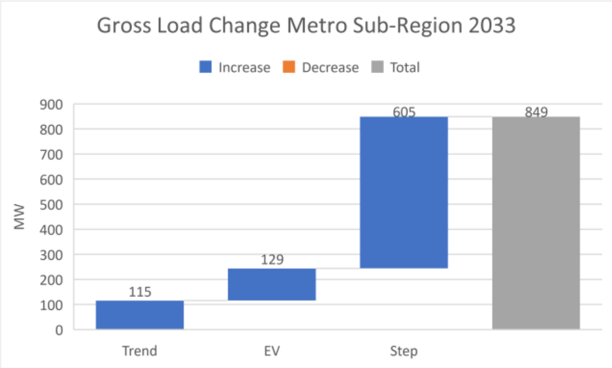


Figure 109: a) Forecasted Gross Load Change Metro Sub-Region by 2028
b) Forecasted Gross Load Change Metro Sub-Region by 2033

5.2.5. Energy Efficiency

In the Company forecast, energy efficiency is shown to have the cumulative effect of reducing the peak load in the North Metro Sub-Region by 2% by 2033 relative to 2023 as shown in Figure . This represents a reduction of 110 MW in the peak load forecast over the planning horizon due to EE measures alone.

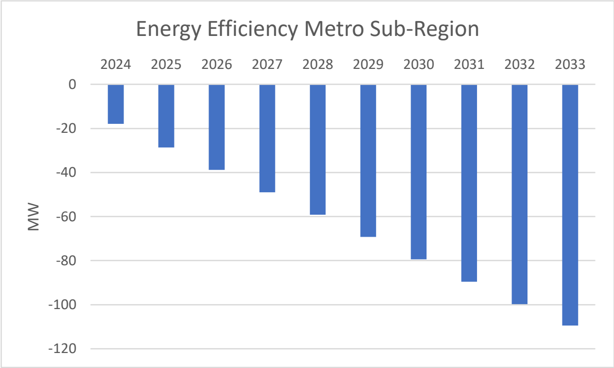


Figure 110: Expected Energy Efficiency Impacts on EMA-North Metro

These values are dependent on the continuation of existing programs (see Section 5.1.7). For the Mass Save program, the Company assumed that the approved 2024 budget of $525M is constant through the 10-year period. As noted, this does not represent forecasted spend as those details will be determined in the Three-Year Plan process. Of that spend, approximately $200M was anticipated to be spent on energy efficiency. If the Three-Year Plans were to change, the overall impact of EE on the aggregated statewide station peaks would change.

In Summary, EE is deferring 110 MVA (more than half a bulk substation worth) of capacity needs over the next decade.

EVERSOURCE

5.2.6. DER Growth: Solar PV, Battery Storage, Grid Services

DER growth, particularly solar PV, is expected to continue impacting the overall EMA-North Metro East Peak. However, comparatively, at a much lower rate than anywhere in the system. This is mostly due to the fact that there are no open spaces to deploy ground mounted solar, and while roof space is available, limitations on the type of roof space (multi-tenant, rental properties, high rises) make this form of DER not an ideal solution for the region. The Company's Forecast therefore only shows the addition or rooftop systems over the course of the next decade.

Further, as more solar generation goes online, the net system peak continuous shifting to later in the day (as discussed in Section 5.1.8), decreasing the incremental impact of the next megawatt of installed solar. Figure 112 shows the relative impact of solar on the net peak, and the corresponding projected installed solar capacity. Based on the figure, solar PV is expected to reduce the peak forecasted demand by just 3 MW due to the time of day of the peak as well as the weather adjustments for firm capacity deferral discussed earlier.

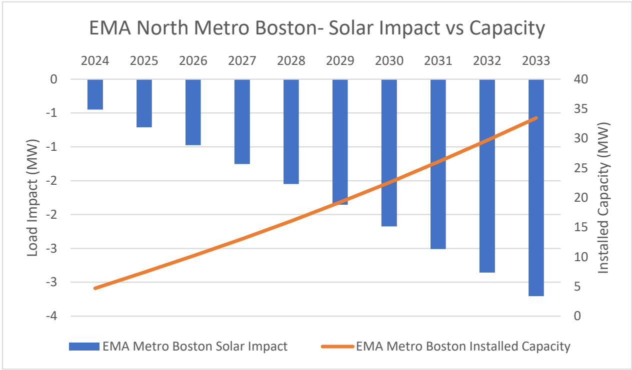
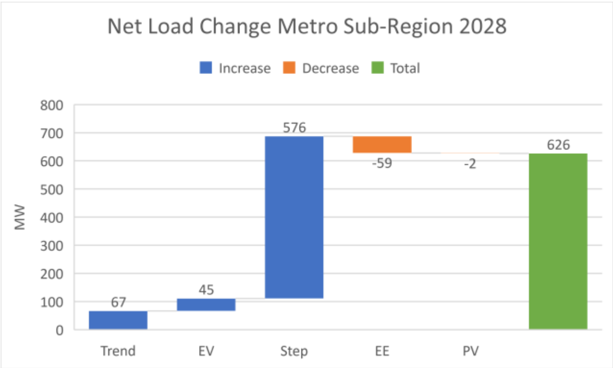


Figure 111: Expected Solar Impacts on Peak Load EMA – North Metro – East and Total Solar Capacity

Figure 112 shows the Net Load Change by 2028 and 2033 respectively across the Metro Sub-Region. Very clearly visible again, the high impact of Step Loads in the first 5 years.



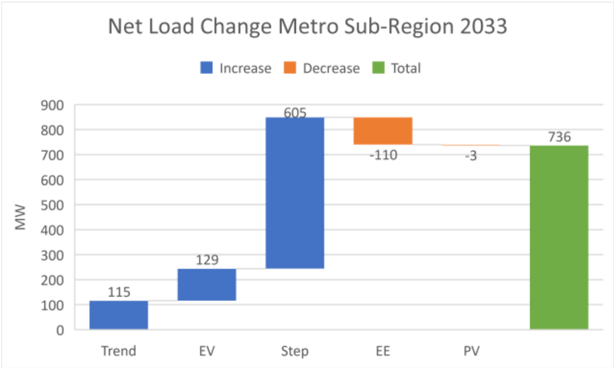


Figure 112: a) Aggregated Net Load Change for Metro Sub-Region by 2028 b) Aggregated Net Load Change for Metro Sub-Region by 2033

5.2.7. Heat Electrification

While the forecasted heating electrification does not yet impact the 10-year summer peak forecast as outlined in Section 5.1, the Company does monitor its forecasted values to understand how fast the heating load is growing and to better understand when the winter peak will surpass the summer peak on the system. For the EMA-North Metro Sub-Region the Company does not expect to be winter peaking by 2035.

For the EMA – North Metro Sub-Region the Company is expecting to see 962 MW of winter peak coincident contribution from heating. The coincident peak of the Sub-Region is expected to occur at 9 am and reach 2.8 GW total as shown in Figure 113. The solar reduction at this point drops at a statewide level with the peak now occurring during winter mornings, resulting in a lower firm capacity being attributed. With the change to the long-term demand assessment model, the Company also includes HDV and MDV in the data, which causes an increase on the EV component while the base component is reduced due to the early winter morning time, where base load is significantly lower than during the summer.

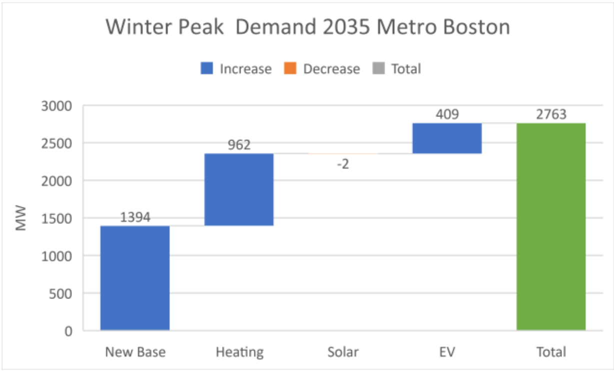


Figure 113: 2035 Winter Peak Components Metro Sub-Region

5.2.8. Summary

The aggregated net peak summer load for the EMA-North Metro – East Sub-Region is expected to increase by 736 MW through 2033 with most of the load increase driven through the development of new loads (Step Loads) stemming from a significant increase in C&I development, as well as large bulk fleet electrification efforts. Offsetting this significant increase is EE, which is assumed to continue with stable funding levels through the forecast horizon and historically stable impacts on the peak load. Solar PV can offset the peak load increase also, but because the time of peak is in the late afternoon to early evening periods, solar PV has limited impact on this region’s overall peak.

5.3. EMA-North Metro West Sub-Region

The EMA-North Metro – West Sub-Region's forecast over the next decade while still including a decent portion of step loads is much less dominated by its neighboring region's step load growth. Also, due to a more sub-urban nature of the region, potential for solar impacts to defer substation needs is significantly (more than a factor of three) higher. On the flip side, EVs have a larger impact on the regions with returning evening commutes to the sub-urban regions.

5.3.1. Aggregate Demand – Summer and Winter

Over the next decade the electric demand for the summer (design peak) in the EMA-North Metro – West Sub-Region is expected to go from 1817 MVA in 2023 to 2091 MVA in 2033 relative to a currently installed bulk capacity of 2.2 GW. This increase to 115% of today's values is driven predominantly through the addition of new loads and electrification of mobility in the region. However, as will be shown later, towards the latter half of the forecast horizon, EV impacts, due to the sub-urban nature of the data, picks up significantly. Figure 114 shows the aggregated station forecasts for the Metro – West Sub-Region. Similarly, to the Metro Sub-Region (although less pronounced), there are two trends observable in this data. In the first 5 years, Eversource sees an uptake of the load due to significant regional additions of new step loads. This results in a short-term jump of the aggregated station peak by 2027.

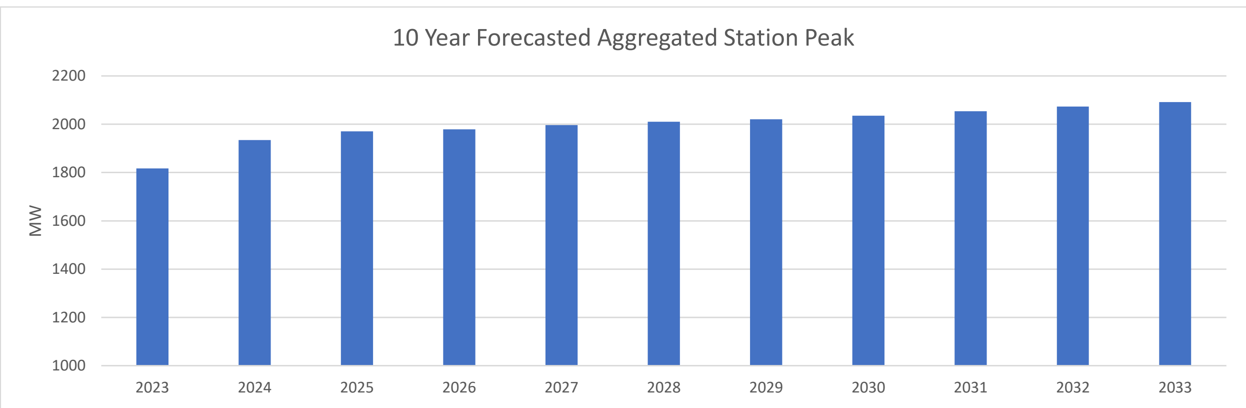


Figure 114: Summer EMA-North Metro West Sub-Region Aggregated Demand

5.3.2. Weather Normalized Econometric Forecast

With the Metro and Metro – West Regions very closely tied geographically and from a business development standpoint, the Company only produces one econometric forecast model for the entire region. For details on the economic development of the EMA-North Metro West Region, please see Section 5.2.

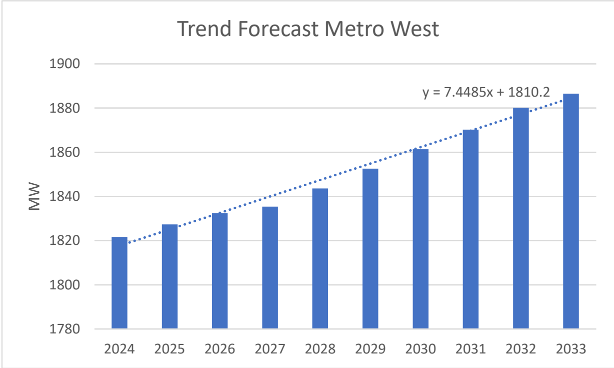


Figure 115: EMA-North Metro – West Sub-Region Econometric Trend Forecast

Figure shows the trend development of the underlying load over the forecast horizon as well as the percentage change from the Base Load. As shown in the figure, the forecasted load increases by 70 MW from 2023 to 2033, based on economic trends.

5.3.3. Electric Vehicles

Over the next 10 years the Company expects that electric vehicles will grow exponentially. Figure shows the expected update on EV load contribution to summer peak load as well as the percentage change relative to the 2023 base load.

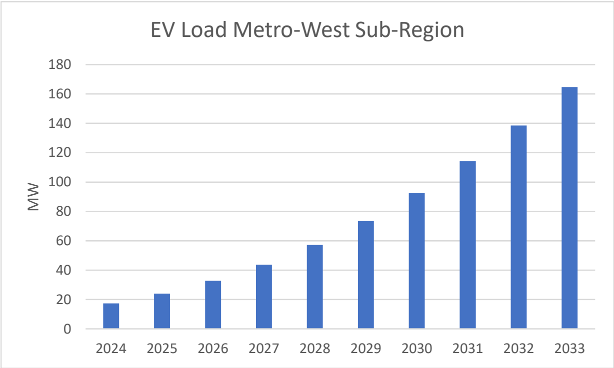


Figure 116: Expected EV Impact on Peak Load EMA – North Metro – West

For the Metro – West Sub-Region, the relative impact of EVs is expected to be higher compared to the Metro Sub-Region as the mobility data shows a higher evening concentration of potential charging cycles within the sub – urban regions as well as a higher total trip termination count. Figure 117 below shows the mobility data with trips being terminated (vehicles arriving into region) during a summer workday in the Metro – West Sub-Region which compares to Figure 104 in Section 5.2.1.

If step loads for MDV and HDV materialize in the region as supported by their transition in the All Options Pathways, the Company is expecting an additional 36.9 MW and 23.2 MW respectively.

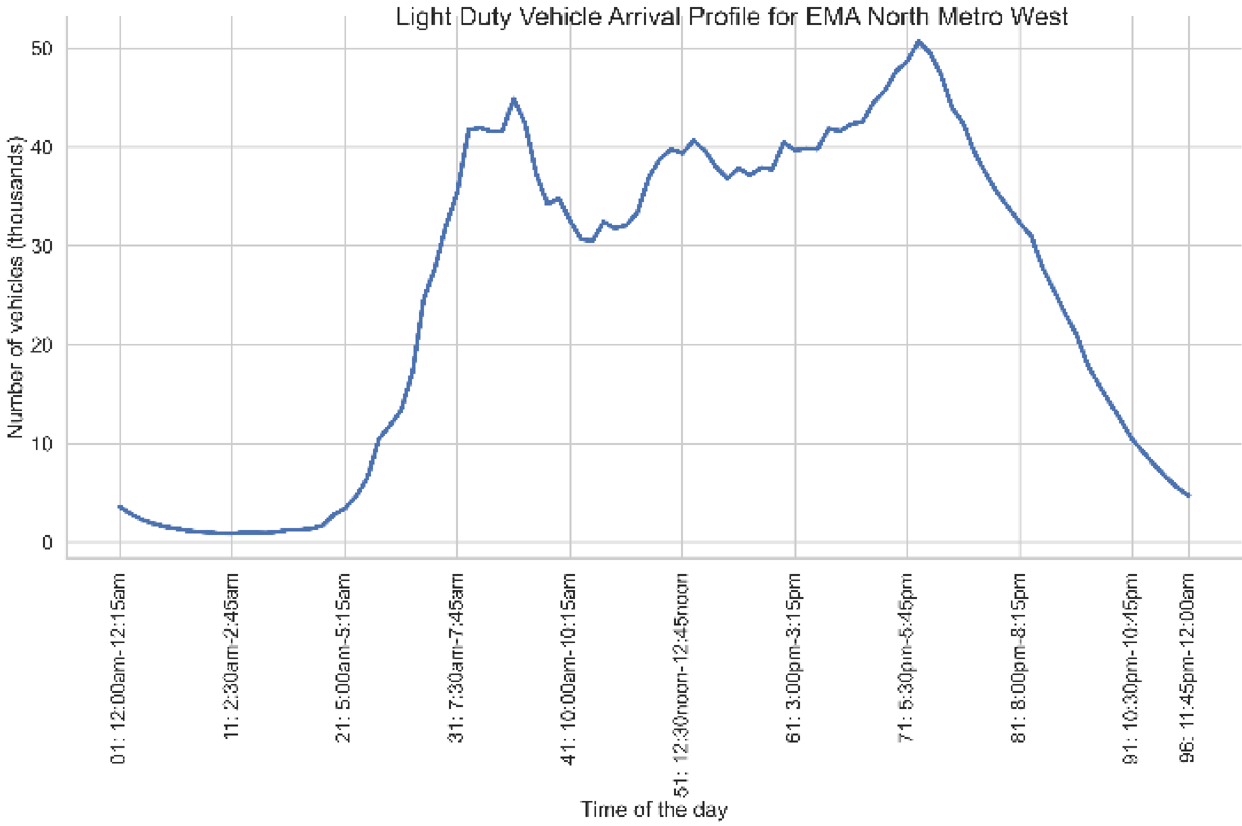


Figure 117: Light Duty Vehicle Arrival Profile for EMA North Metro West

5.3.4. Large Load (Step/Spot Load)

While significantly less prominent even within the EMA-North Metro Sub-Region, step loads constitute the largest driver of electric system demand in the EMA-North Metro – West Region today. However, due to the planning uncertainty around the step load development outlined in Section 5.1.2.5, the Company typically has limited visibility beyond the five-year horizon. Within this five-year horizon, 2023-2027, the Company has knowledge of and is expecting more than 189 MW of step loads to come onto the system as shown in Figure . While falling short of the levels observed in the Metro – Boston Sub-Region, Step loads still constitute the largest single driver of load.

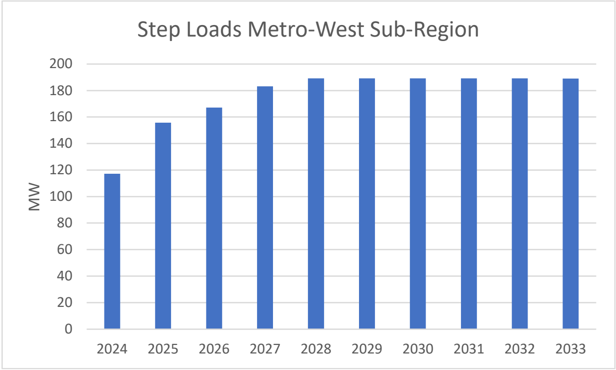


Figure 118: EMA-North Metro – West Step Load Forecast

Furthermore, based on the trend in new business development in the Metro West Region, years 6-10 in the forecast are expected to see similar step loads, unless the overall economic trend slows down.

Figure 119 below shows the aggregated gross load change across the regions for both 2028 and 2033. Again, clearly visible the impact of step loads on the near-term forecast.

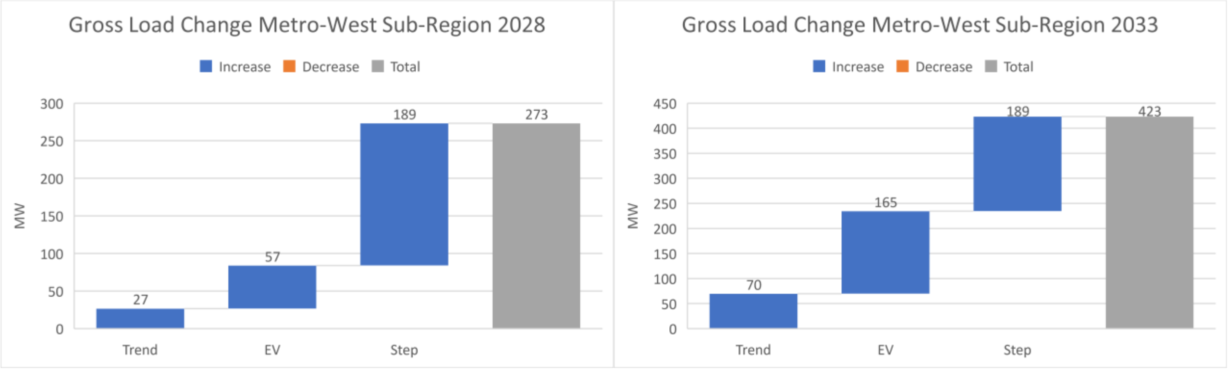


Figure 119: a) Forecasted Gross Load Change Metro West Sub-Region by 2028
b) Forecasted Gross Load Change Metro West Sub-Region by 2033

EVERSOURCE

5.3.5. Energy Efficiency

In the Company forecast, energy efficiency is shown to have the cumulative effect of reducing the peak load in the EMA-North Metro – West Sub-Region by 90 MW by 2033 as shown in Figure below. This represents in the peak load forecast over the planning horizon due to EE measures is discussed earlier in Section 5.1.2. These values are dependent on the continuation of existing programs (see Section 5.1.7). Even with a relatively high remaining potential over the next decade of 89 MW, which equates to about half the capacity of a single bulk substations, the new incoming load dwarfs these savings.

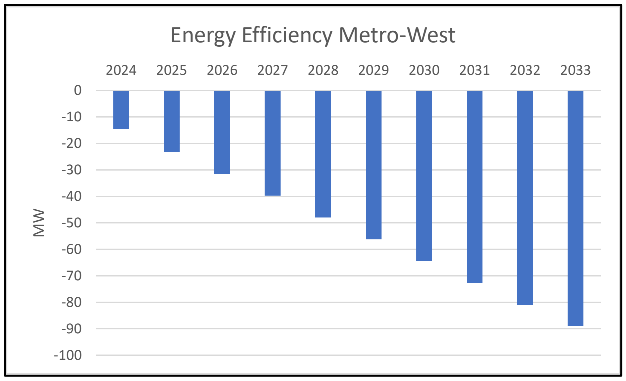


Figure 120: Expected statewide Energy Efficiency Impacts on EMA-North Metro – West Peak

EVERSOURCE

5.3.6. DER Growth: Solar PV, Battery Storage, Grid Services

DER growth, particularly solar PV, is expected to continue impacting the overall EMA-North Metro – West Peak. With the Metro – West Sub-Region representing a suburban region as compared to the more urban environment of the Metro Sub-Region, the expected solar build out in the Region is also significantly higher and more impact full allowing a deferral of more capacity needs over the next decade.

As with all regions, the more solar generation goes online, the net system peak continuous shifting to later in the day (as discussed in Section 5.2.6) and decreases the incremental impact of the next MW of installed solar. Figure shows the relative impact of solar on the net peak and the corresponding projected installed solar capacity. Based on the figure, solar PV is expected to reduce the peak forecasted demand by 60 MW over the planning horizon.

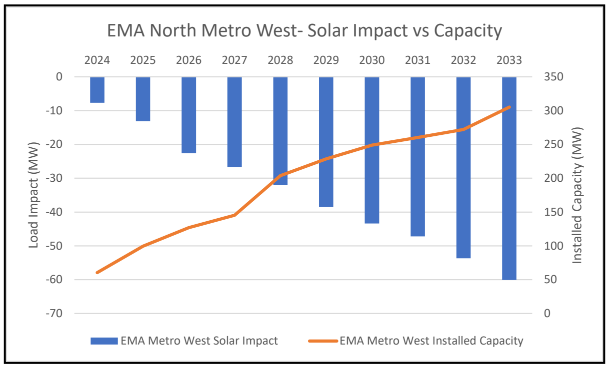


Figure 121: Expected Solar Impacts on Peak Load EMA – North Metro – West and Total Solar Capacity

The resulting total Net Load increase over the next decade is with 198 MVA about 45% lower than the Gross Load increase showing the impacts of energy efficiency and solar PV in deferring capacity needs. Figure 122 shows the Net Load Change by 2028 and 2033 respectively across the Metro West Sub-Region. Very clearly visible again, the high impact of Step Loads in the first 5 years.

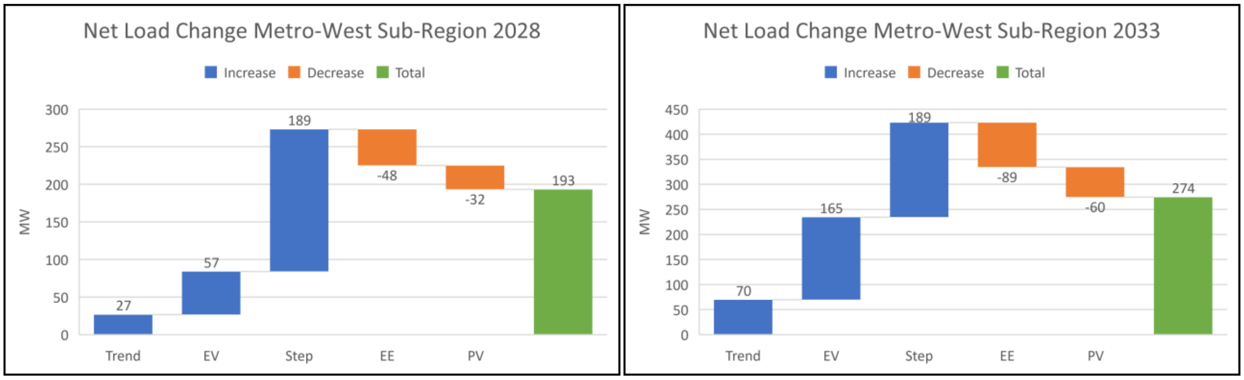


Figure 122: a) Aggregated Net Load Change for Metro Sub-Region by 2028 b) Aggregated Net Load Change for Metro Sub-Region by 2033

5.3.7. Heat Electrification

While the forecasted heating electrification does not yet impact the 10-year summer peak forecast as outlined in Section 5.1, the Company does monitor its forecasted values to understand how fast the heating load is growing and to better understand when the winter peak will surpass the summer peak on the system. The Company expects that it will be winter peaking by 2035.

For the EMA – North Metro West Sub-Region the Company is expecting to see 1740 MW of winter peak coincident contribution from heating. The coincident peak of the Sub-Region is expected to occur at 9 am and reach 3.2 GW total as shown in Figure 123. The solar reduction at this point drops at a statewide level with the peak now occurring during winter mornings, resulting in a lower firm capacity being attributed. With the change to the long-term demand assessment model, the Company also includes HDV and MDV in the data, which causes an increase on the EV component while the base component is reduced due to the early winter morning time, where base load is significantly lower than during the summer.

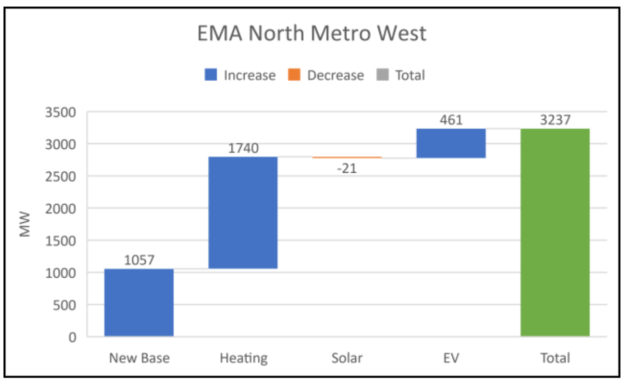


Figure 123: 2035 Metro West Winter Peak Components

5.3.8. Summary

The aggregated peak summer load for the EMA-North Metro – West Sub-Region is expected to increase by 274 MW through 2033 with most of the load increase driven by the development of new loads (Step Loads) stemming from an increase in C&I development, as well as large bulk fleet electrification efforts. Offsetting this is EE, which is assumed to continue with stable funding levels through the forecast horizon and historically stable impacts on the peak load, as well as solar PV. In the EMA-North Metro – West Sub-Region, solar capacity deferral is still relatively impactful as there are an estimated remaining potential for ground mounted solar.

5.4. EMA-South Sub-Region

The EMA – South Sub-Region represents one of the two Company's high distributed generation development regions. With 5 (approved and pending approval) group studies in the region, almost the entire service territory of the EMA – South Sub-Region is directly impacted by the solar development. The Company had, as part of its regulatory filings 22-47, 22-51, 22-52, 22-53, 22-54, and 22-55 evaluated how much of the electrification in the region could be handled through the projects, and with the exception of the Cape Group Study, the intended build out will address large portions of the electrification need. This highlights that in a region such as the Cape, distribution generation need is the key driver of capacity build out.

5.4.1. Aggregate Demand – Summer and Winter

Over the next decade the electric demand for the summer (design peak) in the EMA – South Sub-Region is expected to go from 1214 MVA in 2023 to 1378 MVA in 2033, relative to a current installed bulk capacity of 1.2 GW. This increase to 113% of today's values is driven predominantly through the addition of new loads and electrification of mobility in the region. Figure 55 shows the aggregated station forecasts for the South Sub-Region. With very little step loads in the mix, the main driver of load growth in the region is based on electric vehicles which, given the expected exponential growth across the state (Section 5.1.5) kicks in heavily towards the end of the forecasted decade.

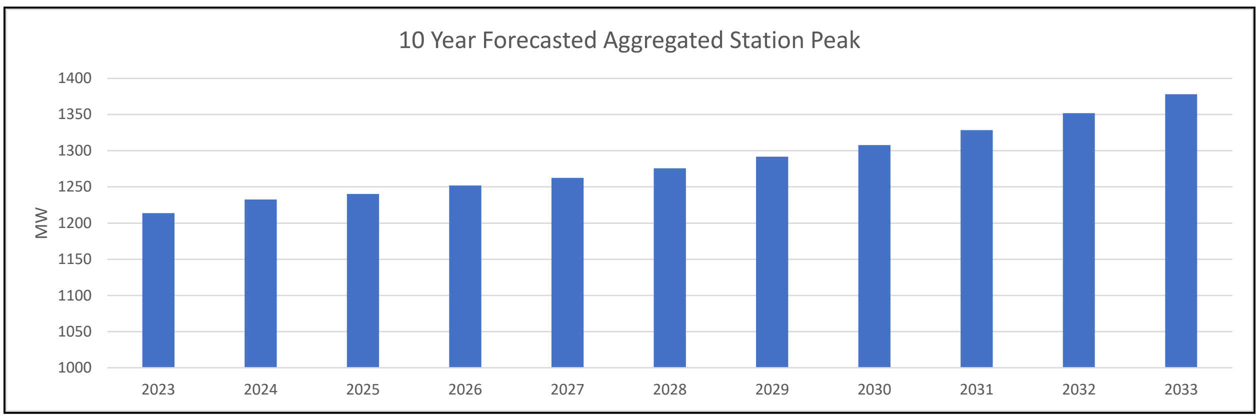


Figure 124: Summer EMA – South Sub-Region Aggregated Demand

5.4.2. Weather Normalized Econometric Forecast

Eastern Massachusetts (South) Gross Metro Product (GMP) has displayed moderate growth over the last five years but is optimistically forecasted to almost double its growth in the coming five years. Real household income remains elevated since the pandemic and is forecasted to continue to grow at an average rate of 1.2% over the next five years. Total employment is forecasted to stay relatively stable; however, it is not forecasted to reach pre-pandemic levels until 2024/2025. Unemployment is due to rise in the coming years as higher interest rates attempt to loosen the tight labor market. Finally, housing is forecasted to show impressive gains in the coming five years despite elevated interest rates, as this region continues its high rate of growth.

Table 39: Key Economic Variables for the EMA South Region

	Eastern MA South Economic Statistics*				
	Gross Metro Product	Real Household Income	Total Employment	Unemployment Rate	Housing Starts
2019	92	123,160	842	3.7	2,557
2020	88	131,481	769	9.9	2,666
2021	93	135,090	802	5.9	2,928
2022	94	127,032	831	3.9	2,866
2023	95	128,876	840	3.8	2,878
2024	*96*	*130,568*	*841*	*4.8*	*3,297*
2025	*97*	*131,936*	*843*	*5.2*	*3,763*
2026	*99*	*134,008*	*844*	*5.4*	*3,955*
2027	*101*	*136,344*	*844*	*5.5*	*3,923*
2028	*103*	*138,546*	*844*	*5.5*	*3,815*
CAGR '19-'23	0.8%	0.9%	0.0%	0.6%	2.4%
CAGR '24-'28	*1.6%*	*1.2%*	*0.1%*	*2.8%*	*3.0%*
**Source: Moody's Analytics data for Barnstable, MA and Providence, RI*					

Using the weather normalized econometric trend forecast outlined in Section 5.1.1 growth of the underlying, existing load. Figure 125 shows the trend development of the underlying load over the forecast horizon as well as the percentage change from the Base Load. The EMA – South Region shows the relatively highest underlying Trend Growth over the forecast horizon.

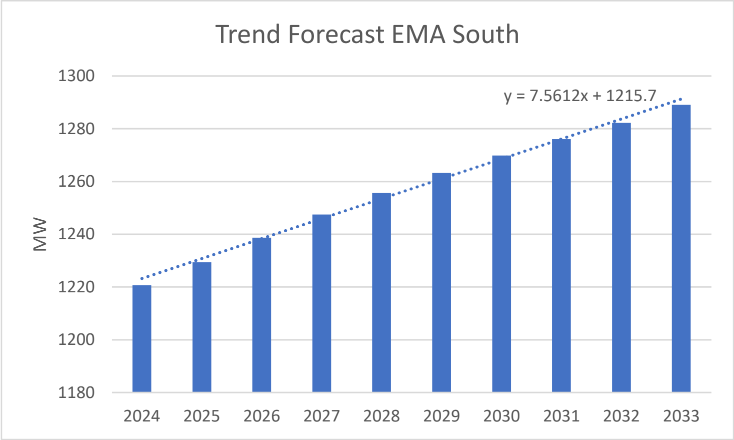


Figure 125: EMA-South Sub-Region Econometric Trend Forecast

5.4.3. Electric Vehicles

Over the next 10 years the Company expects that electric vehicles will grow exponentially. Figure shows the expected update on EV load contribution to summer peak load. For the EMA – South Sub-Region the impacts are expected to field towards the statewide averages, neither being pushed up by proximity to the metro suburb regions or being constraint within the downtown areas. Mobility patters are also not showing any skewed impacts due to a metro region proximity and charging patters are expected to result in a normal, evening commute return peak on the system (Figure 127).

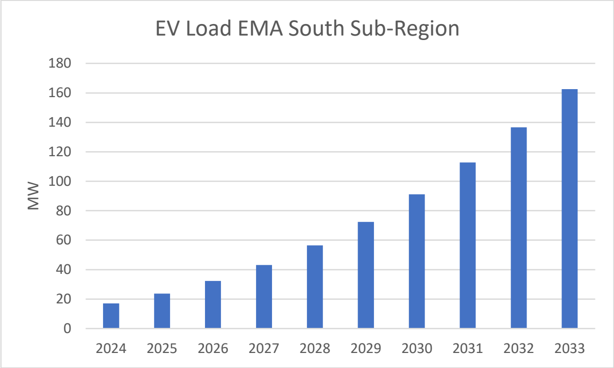


Figure 126: Expected EV Impact on Peak Load EMA – South

If step loads for MDV and HDV materialize in the region as supported by their transition in the All Options Pathways, the Company is expecting an additional 43.5 MW and 11.8 MW respectively.

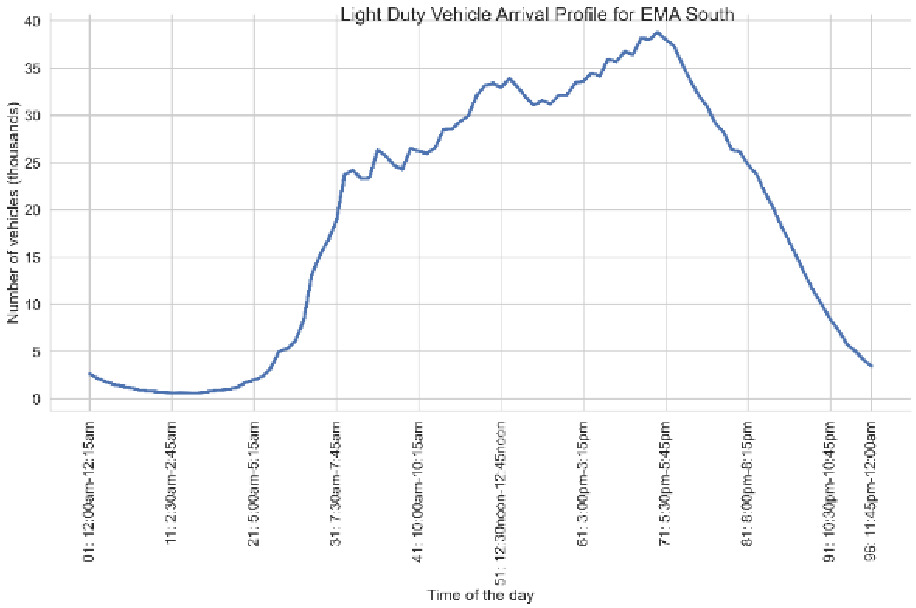
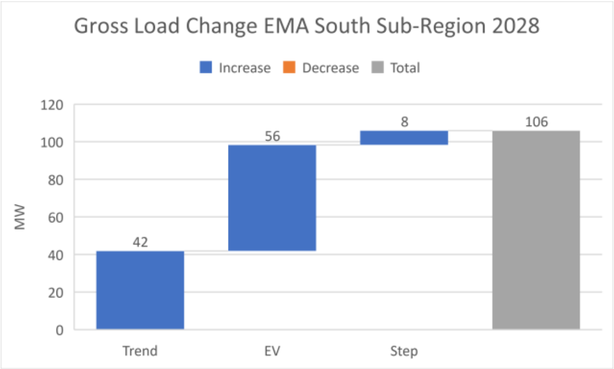


Figure 127: Light Duty Vehicle Profile for EMA South Sub-Region

5.4.4. Large Load (Step/Spot Load)

The EMA – South region shows the smallest overall step load growth of all regions reported in the five- and ten-year forecast. Showing most of its growth on the residential side, there is relatively little impact from large new developments currently reported. This can however change if e.g. public transit services or other fleet operates initiate projects to add additional electrification load. But as it stands today, the Company knows of only five individual step load developments in the entire region totaling just above 7.7 MVA with all Step Loads expected to enter the system by 2024 with no further changes in the line of site till 2033. Moderate load additions have been discussed with various Large C&I Customers related to state and organizational de-carbonization goals.

Figure 128 below shows the aggregated gross load change across the regions for both 2028 and 2033. Unlike the previous two regions, the EMA – South Region does not have a significant step load component and sees its load driven heavily by electric vehicles.



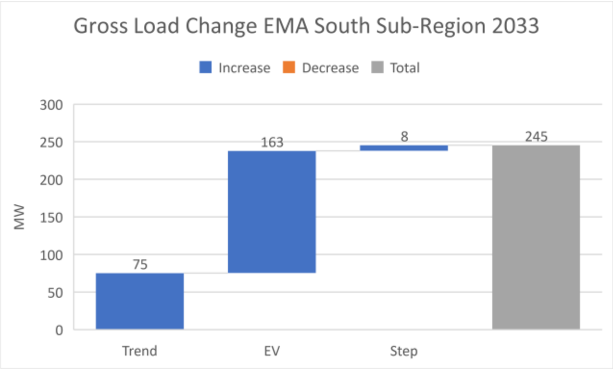


Figure 128: a) Forecasted Gross Load Change EMA-South Sub-Region by 2028
b) Forecasted Gross Load Change EMA-South Sub-Region by 2033

EVERSOURCE

5.4.5. Energy Efficiency

In the Company forecast, energy efficiency is shown to have the cumulative effect of reducing the peak load in the EMA – South Sub-Region by 43 MW by 2033 as shown in Figure below. This represents a reduction of the peak load forecast over the planning horizon due to EE measures alone, as discussed earlier in Section 5.1.2. These values are dependent on the continuation of existing programs (see Section 5.1.7).

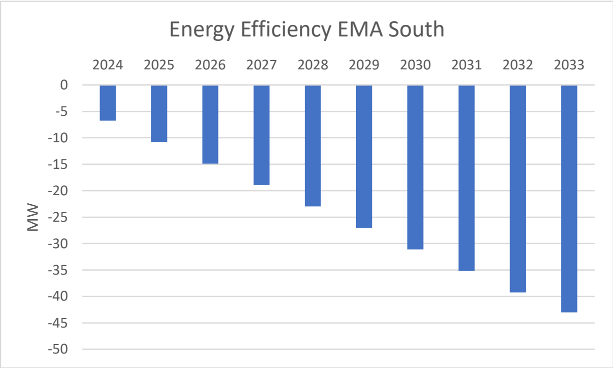


Figure 129: Expected Energy Efficiency Impacts on EMA – South Peak

5.4.6. DER Growth: Solar PV, Battery Storage, Grid Services

DER Growth is expected to continue impacting the overall EMA – South. As however more solar generation goes online the net system peak continuous shifting to later in the day, decreasing the incremental impact of the next MW of installed solar. While the EMA – South Region suffers specifically from this effect in terms of solar impact to peak (see discrepancy in Figure 131 between the impact to peak and the installed capacity), the EMA – South Region does still pose the largest load deferral in relative numbers, of all Sub-Regions. This is in parts due to the land availability, as well as the expected impacts on solar development through the development of the CIP projects in the region.

At the time the forecast was created none of the Company's CIPs in the EMA South Sub-Region had been approved. As a result, there is almost no remaining station capacity for ground mounted solar available stalling the entire build out. With D.P.U. 22-47 order issued and the Company expecting orders on the remaining CIPs in the near-term, the forecasted ground mounted solar will increase significantly. There are currently already 281 MW of solar awaiting interconnection as members of the group studies.

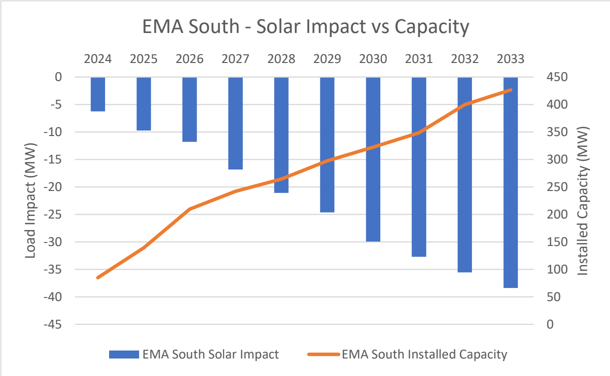


Figure 130: Expected Solar Impacts on Peak Load EMA – South and Total Solar Capacity

Figure 131 shows the Net Load Change by 2028 and 2033 respectively across the EMA South Sub-Region. Very clearly visible again, the high impact of Step Loads in the first 5 years.

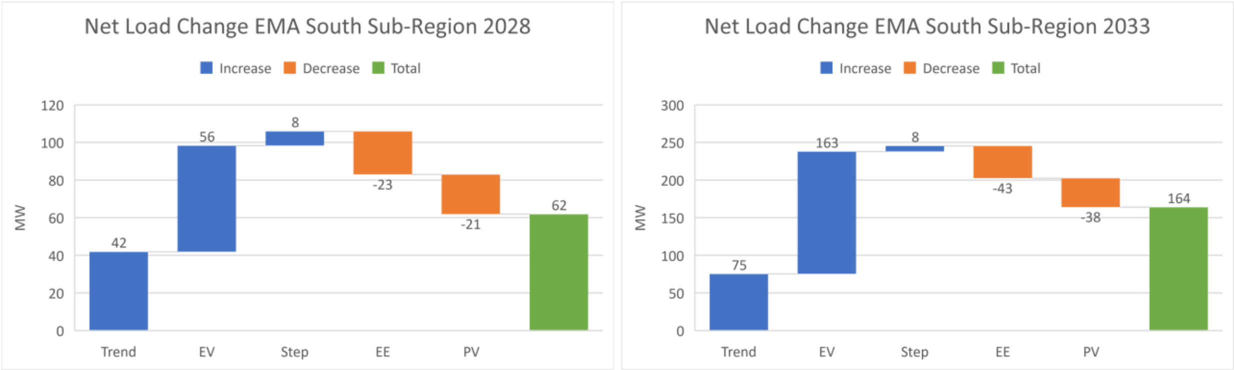


Figure 131: a) Aggregated Net Load Change for EMA South Sub-Region by 2028 b) Aggregated Net Load Change for EMA South Sub-Region by 2033

5.4.7. Heat Electrification

For the EMA – South West Sub-Region the Company is expecting to see 764 MW of winter peak coincident contribution from heating. The coincident peal of the Sub-Region is expected to occur at 9 am and reach 1.7 GW total as shown in Figure 132. The solar reduction at this point drops at a statewide level with the peak now occurring during winter mornings, resulting in a lower firm capacity being attributed. With the change to the long-term demand assessment model, the Company also includes HDV and MDV in the data, which causes an increase on the EV component while the base component is reduced due to the early winter morning time, where base load is significantly lower than during the summer. For the SEMA region, the Company expects to be winter peaking by 2035.

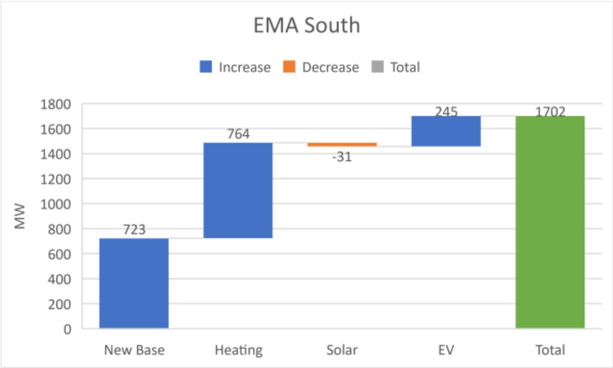


Figure 132: 2035 EMA South Winter Peak Components

5.4.8. Summary

The aggregated peak summer load for the EMA – South Sub-Region is expected to increase by 164 MW till 2033 with most of the load increase driven through the development of the underlying trend load as well as vehicular electrification. Offsetting this increase is EE, which is assumed to continue with stable funding levels through the forecast horizon and historically stable impacts on the peak load, as well as solar PV. Solar in the region has a comparatively high impact on the regional aggregated demand forecast, even with peaks shifting to later times during the day, with significant land availability and high developer interest in the region. The resulting increase constitutes a change of 14% to the 2022 reported peak, a significant uptake that has yet to include the expected impacts from electric heating.

5.5. WMA Sub-Region

The WMA Sub-Region represents a rural area of the Company's service territory with overall relatively low load growth and most of the regions impacts and capacity upgrades in the near term are driven through distributed generation upgrade requirements.

5.5.1. Aggregate Demand – Summer and Winter

Over the next decade the electric demand for the summer (design peak) in the Western Sub-Region is expected to go from 888 MVA in 2023 to 956 MVA in 2033 relative to a currently installed bulk capacity of 1.3 GW. This increase to 108% of today's values. Figure 133 shows the aggregated station forecasts for the Western Sub-Region. With very little step loads in the mix, the main driver of long-term load growth in the region is based on electric vehicles which, given the expected exponential growth across the state (Section 5.1.5) kicks in heavily towards the end of the forecasted decade.

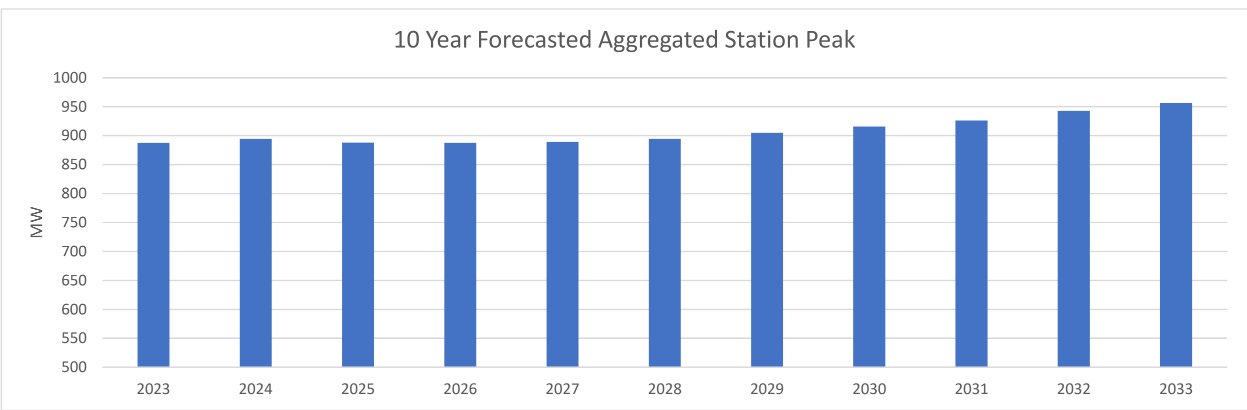


Figure 133: Summer WMA Sub-Region Aggregated Demand

5.5.2. Weather Normalized Econometric Forecast

Western Massachusetts Gross Metro Product (GMP) has displayed slow yet steady growth over the last five years but is optimistically forecasted to almost double its growth in the coming five years. Real household income remains significantly lower than Eversource's other Massachusetts regions; however, displays a similarly optimistic forecast as GMP. Total employment is forecasted to stay relatively stable after making a full recovery to pre-pandemic levels. Unemployment is due to rise in the coming years as higher interest rates attempt to loosen the tight labor market. Finally, housing is forecasted to show substantial gains in the coming year as this metric still fights to return to pre-pandemic levels, but then only show moderate growth once that recovery is achieved.

Western MA Economic Statistics*					
	Gross Metro Product	Real Household Income	Total Employment	Unemployment Rate	Housing Starts
2019	40	119,539	351	3.8	870
2020	38	126,845	318	10.0	843
2021	40	127,979	333	6.5	844
2022	40	118,534	345	4.5	772
2023	41	122,445	351	3.8	756
2024	*42*	*123,704*	*352*	*4.0*	*996*
2025	*43*	*124,748*	*352*	*4.2*	*1,094*
2026	*44*	*126,638*	*353*	*4.2*	*1,117*
2027	*45*	*128,811*	*353*	*4.3*	*1,066*
2028	*46*	*130,844*	*353*	*4.2*	*1,005*
CAGR '19-'23	0.8%	0.5%	0.0%	-0.1%	-2.8%
CAGR '24-'28	*1.7%*	*1.1%*	*0.1%*	*1.3%*	*0.2%*
**Source: Moody's Analytics data for Pittsfield, MA and Springfield, MA*					

Using the weather normalized econometric trend forecast outlined in Section 5.1.1 growth of the underlying, existing load. Figure 134 shows the trend development of the underlying load over the forecast horizon as well as the percentage change from the Base Load.

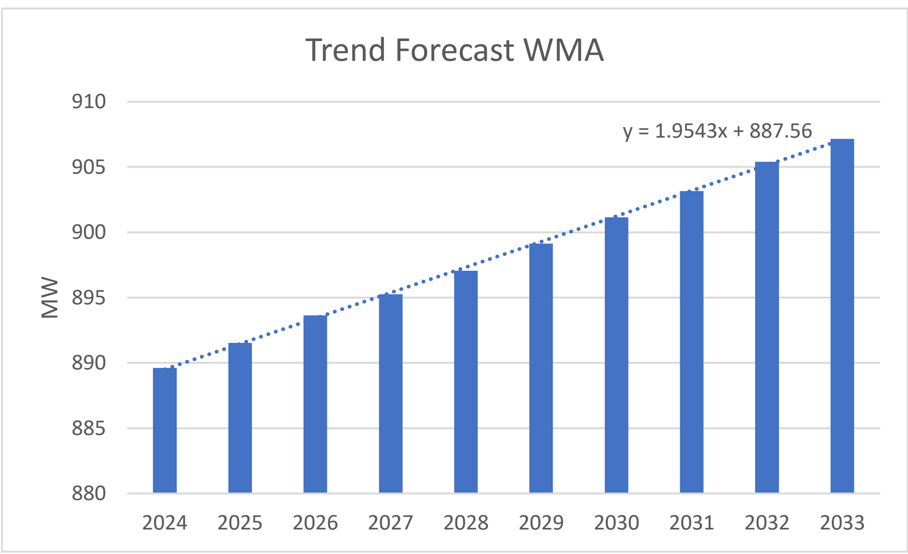


Figure 134: a) WMA Sub-Region Econometric Trend Forecast
b) Aggregated Load Change for the WMA Sub-Region

5.5.3. Electric Vehicles

Over the next 10 years the Company expects that electric vehicles will grow exponentially in the SEMA region. Figure shows the expected update on EV load contribution to summer peak load.

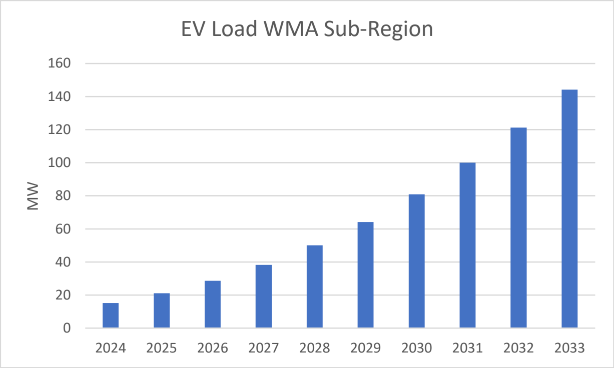


Figure 135: Expected EV Impact on Peak Load WMA

The mobility patterns shown in Figure 137 highlights the driving patterns in the WMA region, with an evening peak on trip terminations. This evening peak will directly impact the existing system peak causing a relatively high (by comparison) EV impact of LDV in the next 10 years.

If step loads for MDV and HDV materialize in the region as supported by their transition in the All Options Pathways, the Company is expecting an additional 37.9 MW and 42.6 MW respectively.

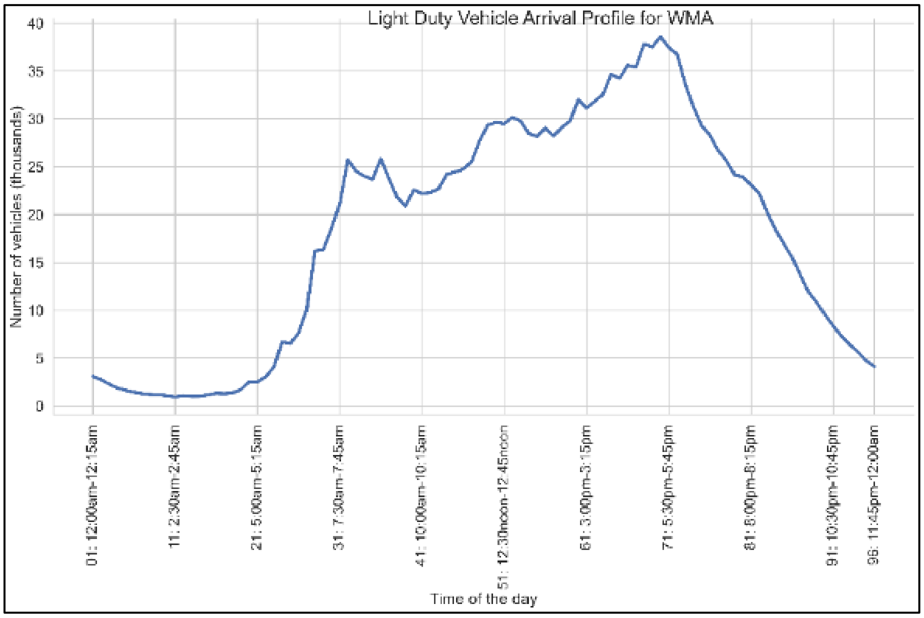


Figure 136: Trip Termination Profile WMA Sub-Region

5.5.4. Large Load (Step/Spot Load)

The WMA Sub-Region has significantly less step load development compared to the Metro Regions laid out in Section 5.2 and 5.3. Most of all of the step load development observed in the WMA Sub-Region is focused along the I-91 Interstate Corridor as seen in Figure .

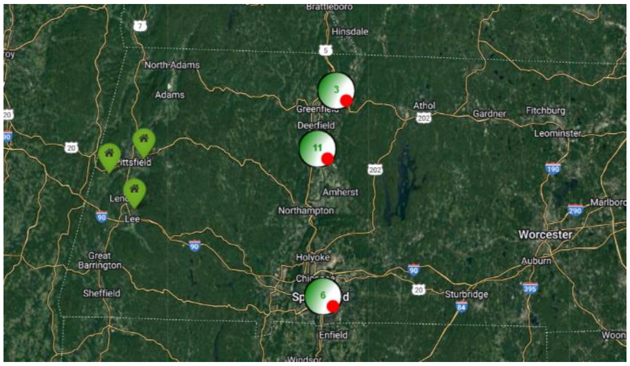


Figure 137: WMA Sub - Region Step Load Locations

In total, the Region shows a little over 30 MVA of expected step loads over the next decade. Most of the Step Loads in the WMA Sub-Region are driven by 71. This moderate increase in forecasted load additions is associated with electrification/decarbonization objectives from Eversource's large C&I Customer base. At this time, the Customer sectors Eversource is having conversations with are institutional (colleges and universities and Public Transportation entities regarding fleet electrification).

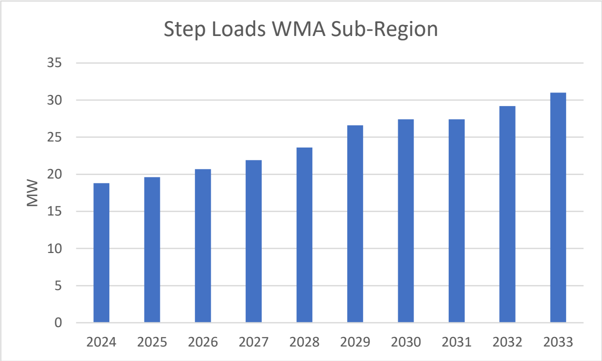


Figure 138: WMA Step Load Forecast

Overall, step loads will drive up the aggregated system peak by 3.11% over the next decade as
depicted in Figure .

Figure 139 below shows the aggregated gross load change across the regions for both 2028 and 2033. Again, clearly visible the impact of step loads on the near-term forecast.

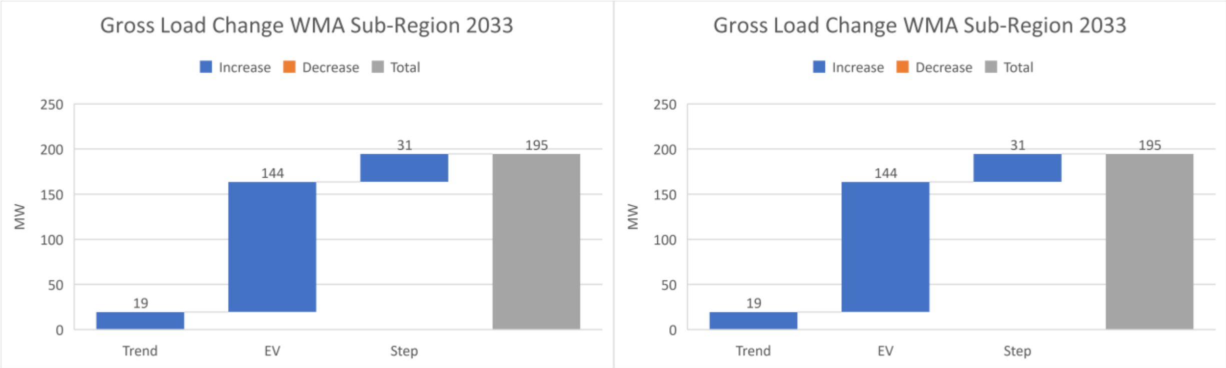


Figure 139: a) Forecasted Gross Load Change WMA Sub-Region by 2028
b) Forecasted Gross Load Change WMA Sub-Region by 2033

5.5.5. Energy Efficiency

In the Company forecast, energy efficiency is shown to have the cumulative effect of reducing the peak load in the WMA Sub-Region by 43 MW by 2033 as shown in Figure . This represents in the peak load forecast over the planning horizon due to EE measures is discussed earlier in Section 5.1.2.1. These values are dependent on the continuation of existing programs (see Section 5.1.7). Even with a relatively high remaining potential over the next decade, the new incoming load dwarfs these savings.

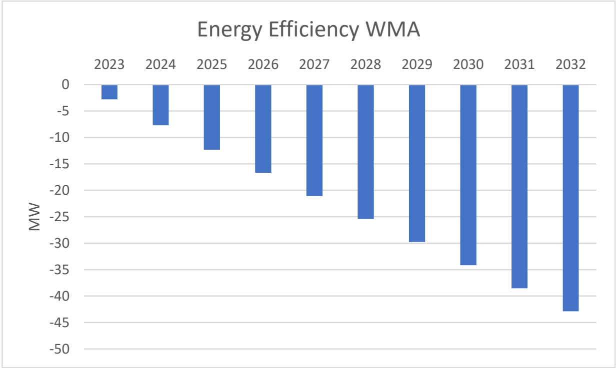


Figure 140: Expected Energy Efficiency Impacts on WMA Net Peak

5.5.6. DER Growth: Solar PV, Battery Storage, Grid Services

DER Growth is expected to continue impacting the overall WMA Sub-Region. As however more solar generation goes online the net system peak continuous shifting to later in the day, decreasing the incremental impact of the next MW of installed solar. This is most obvious in the WMA Sub-Region towards the end of the forecast horizon as solar impacts start tapering off. This stands in contrast with the expected development solar in the region, which is mostly due to the land availability, as well as the expected impacts on solar development through the development of the current and future proposed CIP projects in the region.

For the WMA Sub-Region the forecasts was, similar to the EMA South Sub-Region, completed without the inclusion of any CIPs. The Company expects that update will continue as more capacity becomes available. There are currently 13 MW of solar awaiting interconnection as members of the group studies. Figure shows the relative impact of solar on the net peak and the corresponding projected installed solar capacity.

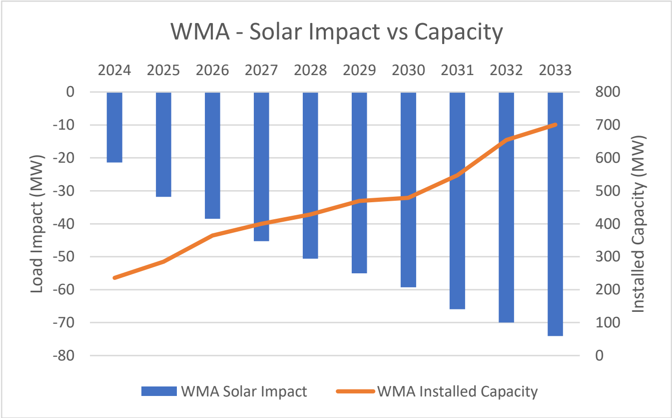


Figure 141: Expected Solar Impacts on Peak Load WMA and Total Solar Capacity

Figure 142 shows the Net Load Change by 2028 and 2033 respectively across the EMA Sub-Region. Very clearly visible again, the high impact of Step Loads in the first 5 years.

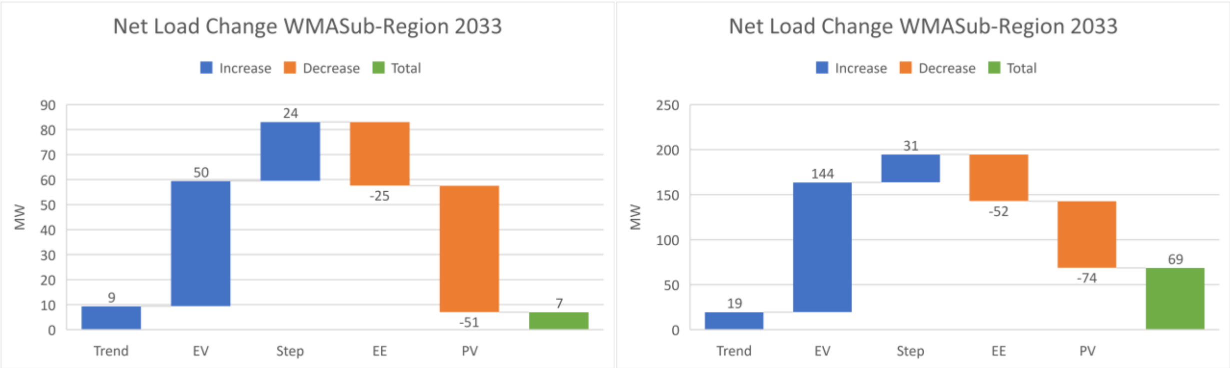


Figure 142: a) Aggregated Net Load Change for WMA Sub-Region by 2028 b) Aggregated Net Load Change for WMA Sub-Region by 2033

5.5.7. Heating Electrification

For the WMA Sub-Region the Company is expecting to see 56 MW of winter peak coincident contribution from heating. The coincident peal of the Sub-Region is expected to occur at 9 am and reach 0.6 GW total as shown in Figure 143. The solar reduction at this point drops at a statewide level with the peak now occurring during winter mornings, resulting in a lower firm capacity being attributed. With the change to the long-term demand assessment model, the Company also includes HDV and MDV in the data, which causes an increase on the EV component while the base component is reduced due to the early winter morning time, where base load is significantly lower than during the summer. For the WMA region, the Company does not expect to be winter peaking by 2035.

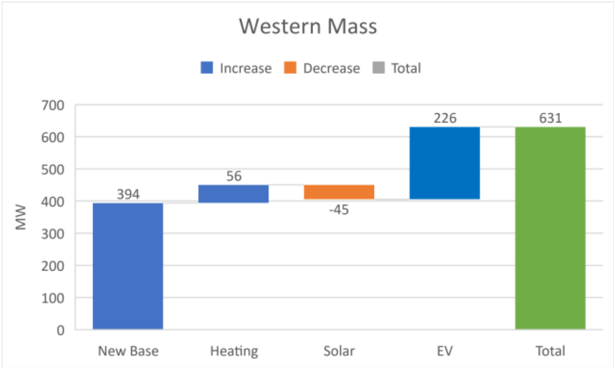


Figure 143: 2035 WMA Winter Peak Components

5.5.8. Summary

The aggregated peak summer load for the WMA Sub-Region is expected to increase by 631 MW till 2033 with most of the load increase driven through EV growth in the region. Offsetting this increase is EE, which is assumed to continue with stable funding levels through the forecast horizon and historically stable impacts on the peak load, as well as solar PV. The EE programs are expecting to have significant continued impact on the region.

6.0 Five- and Ten-Year Planning Solutions: Building for the Future

Section Overview

Eversource's sense of urgency to continue the safe and reliable delivery of energy is exemplified by the planned upgrades to four bulk substations and new substations in progress to mitigate imminent capacity deficiencies in multiple areas. These upgrades, (Somerville in the Metro Boston region; Medway in the Metro West region; and Clinton and Franconia in the Western region), all have planned in-service dates in 2024. The Company is engaged in local community outreach efforts and petitions to the Energy Facilities Siting Board (EFSB) have either already been submitted, or shall be imminently, to ensure timely implementation of these urgently needed new bulk substations to maintain safe and reliable service.

Within the five-year investment period (2025 – 2029) the Company will need to upgrade six bulk substations (Alewife and Maynard in the Metro West region; and Silver, Plainfield, Ludlow, and Partridge in the Western region), construct five new substations (East Cambridge, East Boston, and Hyde Park in Metro Boston; Burlington in Metro West; and Falmouth in the Southeast region), construct a new undersea cable to Martha's Vineyard, and construct two Battery Storage systems (Hyde Park in Boston and Industrial Park in New Bedford) to maintain safe and reliable service. These bulk substation upgrades and additions by 2029, in aggregate, increase the electrification hosting capacity by 1.8 GW. This in addition to the existing 7.9 GW firm capacity, results in the company enabling 100% of the Commonwealth's 2030 goals at the aggregated bulk station level.

In the last five years of the ten-year planning period (2030 - 2034), the Company will need to upgrade two bulk substations (Seaport and Electric Ave in Metro Boston) and construct nine new substations (South End, Charlestown, Fenway, Downtown Network Station in the Metro Boston region; Saxonville/Natick, North Acton, Waltham in the Metro West region; Dennis-Brewster in the Southeast region; and Hilltown in the Western region). These bulk substation upgrades and additions by 2035, in addition to the DER-driven CIPs discussed below are designed to increase the electrification hosting capacity by 3.4 GW, in aggregate. Each new substation, station upgrade and battery storage project require extensive street distribution line upgrades or new distribution lines to ultimately relieve loading on existing distribution feeders.

In addition to increasing the hosting capacity for electrification, these ten-year capital plan upgrades also enable more than 0.9 GWs of DER interconnections. To complement these load-driven upgrades, in the same period, the Company has planned or proposed Capital investment Projects (CIP) to upgrade fourteen (14) bulk substations and construct three new bulk substations (Assonet, East Freetown, Whately-Deerfield) in the

Southeast and Western regions to enable reliable interconnection of about 540 MW of DER solar.

The approved (one) CIP, pending (five) CIPs and newly proposed (seven) CIPs,[120] along with load-driven upgrades, will enable 2.2 GW of solar at a bulk station level which (with existing/planned solar) is 3.6 GW beyond the Commonwealth's 2040 goals, and 72% of its 2050 goals. To the extent the electrification and solar programs are coordinated with the grid capacity upgrades, this ESMP 10-year plan enables 105% of the Commonwealth's 2035 clean energy goals.

Across the Eversource territory, the available electrification headroom enables 4.2 million Electric Vehicles (Statewide) and the equivalent of 1 million residential Heat Pumps by 2040. To the extent the electrification and solar programs are coordinated with the grid capacity upgrades, this ESMP 10-year plan enables 100% of the Commonwealth's 2040 clean energy goals at an aggregated, system wide bulk station level.

The Company recognizes that construction of these 17 new bulk-substations and upgrade of 26 bulk substations by 2035, to ensure that the distribution bulk substation capacity is able to support the projected electric demand (from both increased load and DER), will require thoughtful engagement with the local communities to assist with site selection, design and construction consistent with the Company's Equity framework. Active stakeholder engagement in the EDC decision-making process is critical to the successful execution of these projects.

Building system capacity with substations and battery storage systems will provide a critical foundation for enabling electrification and reliable interconnection of DERs. A comprehensive and cost-effective solution to meet the Commonwealth's clean energy objectives must also include technology platforms that support customer engagement and the use of DERs to provide grid services to increase flexibility and address local constraints. One of the most important foundational investments is the Company's deployment of advanced metering infrastructure (AMI). By 2028, all customers will have greater insights into their usage information and more tools to engage in demand response and clean energy programs. To support the use of customer-owned DER as a grid asset, the Company is proposing investments that will enable the use of Virtual Power Plant (VPP) technology to address system constraints and defer the need for system upgrades into the future where applicable.

---

[120] Described later in Section 6.6.1 for Metro West, Section 6.7.1 for Southeast and Section 6.8.1 for Western region.

While this plan focuses on distribution system modernization, it should be noted that associated transmission system upgrades, are also an integral component of the overall electric system buildout. Transmission system upgrades are not discussed in detail in this document. The following newly proposed bulk distribution substations all require new transmission sources. In some cases, upstream transmission infrastructure may be inadequate for the magnitude of increased energy demand from electrification, thereby necessitating large-scale transmission expansions to provide additional import/export capability between geographic areas. Transmission upgrades also facilitate renewable energy integration and deliverability, improve grid resilience and storm hardening, reduce line losses, and enhance voltage stability and regulation. Developing new transmission lines, including the design, siting, and construction phases, can take approximately eight to ten years – significantly longer than distribution projects. In this era marked by the urgent need to transition to clean and sustainable energy sources, coupled with distribution system modernization plans, it is a strategic imperative to support and accelerate transmission projects; not just as a procedural step, but necessary to achieve the Commonwealth's decarbonization objectives.

6.1. Summary of Existing Investment Areas and Implementation Plans

Figure 144 below shows a high-level timeline for implementation of five- and ten-year *load-driven* planning solutions in the capital plan. New substation projects are highlighted in dark green. All projects with in-service dates (ISD) in 2025 or earlier are in the first segment of the chart. This includes ongoing (immediate) substation upgrades, with 2024 ISDs, two new bulk substations with 2025 ISDs, two battery energy storage projects and the Martha's Vineyard cable projects also with 2025 ISDs. The second segment of the chart lists any additional project with an ISD in 2030 or earlier. This includes four new substations and several substation upgrades. The last segment of the chart lists all additional projects with ISD in 2035 or earlier. This includes eight new substations and one substation upgrade.

Figure 145 is a geographic view of all the proposed and approved substation upgrade projects shown in Figure 144, as well as the approved, pending and proposed CIPs for DER interconnection across the Eversource territory within the ten-year planning horizon. The locations of the load-driven upgrade projects, shown on the chart in Figure 144 are indicated by orange boxes. The locations of the DER-driven CIP upgrades are indicated by green boxes.

The temporal and spatial scale of the required investments over the ten-year planning horizon is a testiment to 1) the real and pronounced capacity and reliability needs across the sub-regions, 2) the growth in DER adoption driven by policy incetives and state goals, 3) the Company's commitment to meet its obligation to provide safe, reliable service to all customers while enabling just transition to an electrified future.

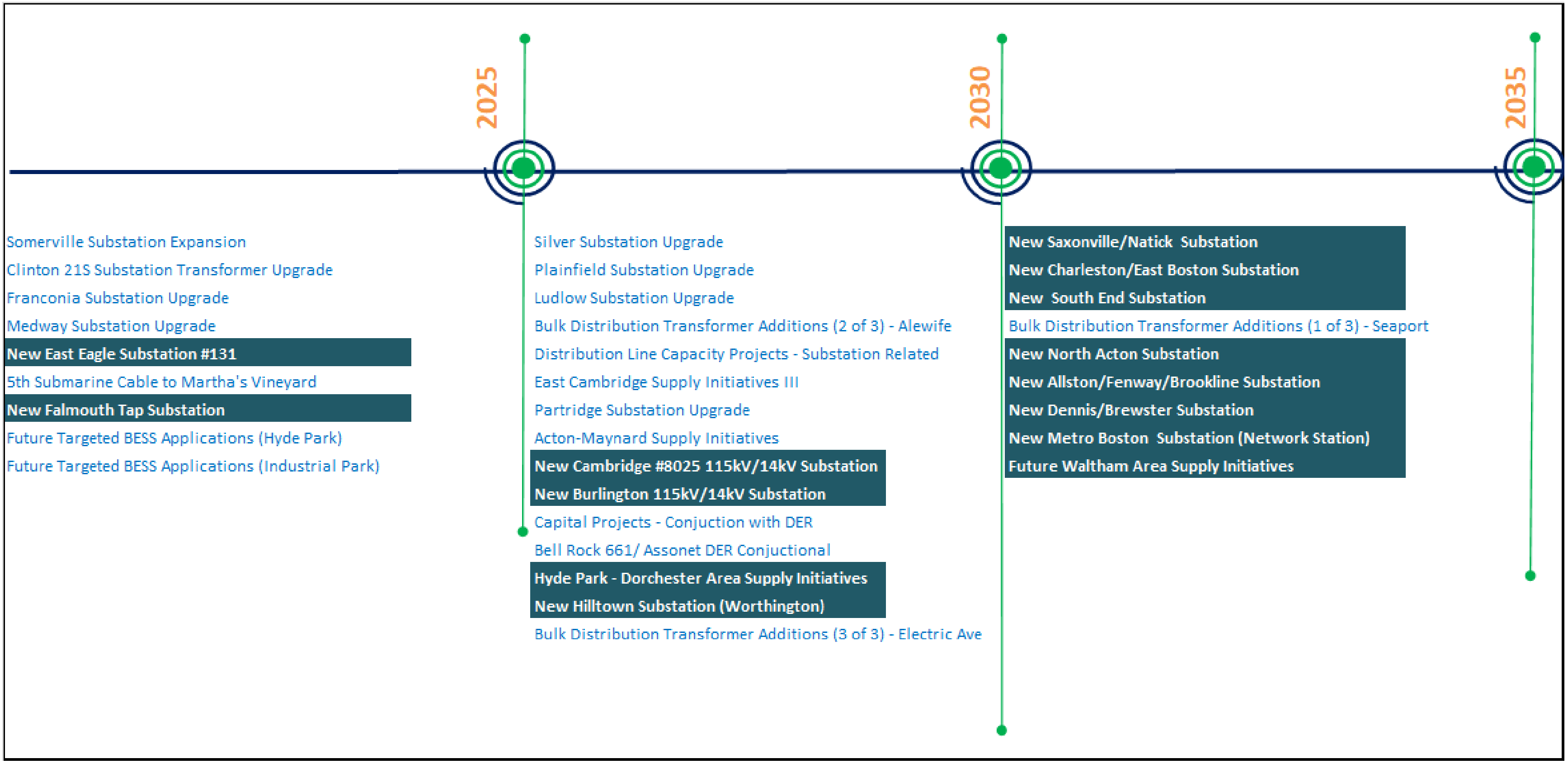


Figure 144: Scheduled Implementation of Major Distribution Infrastructure Projects in the Capital Plan

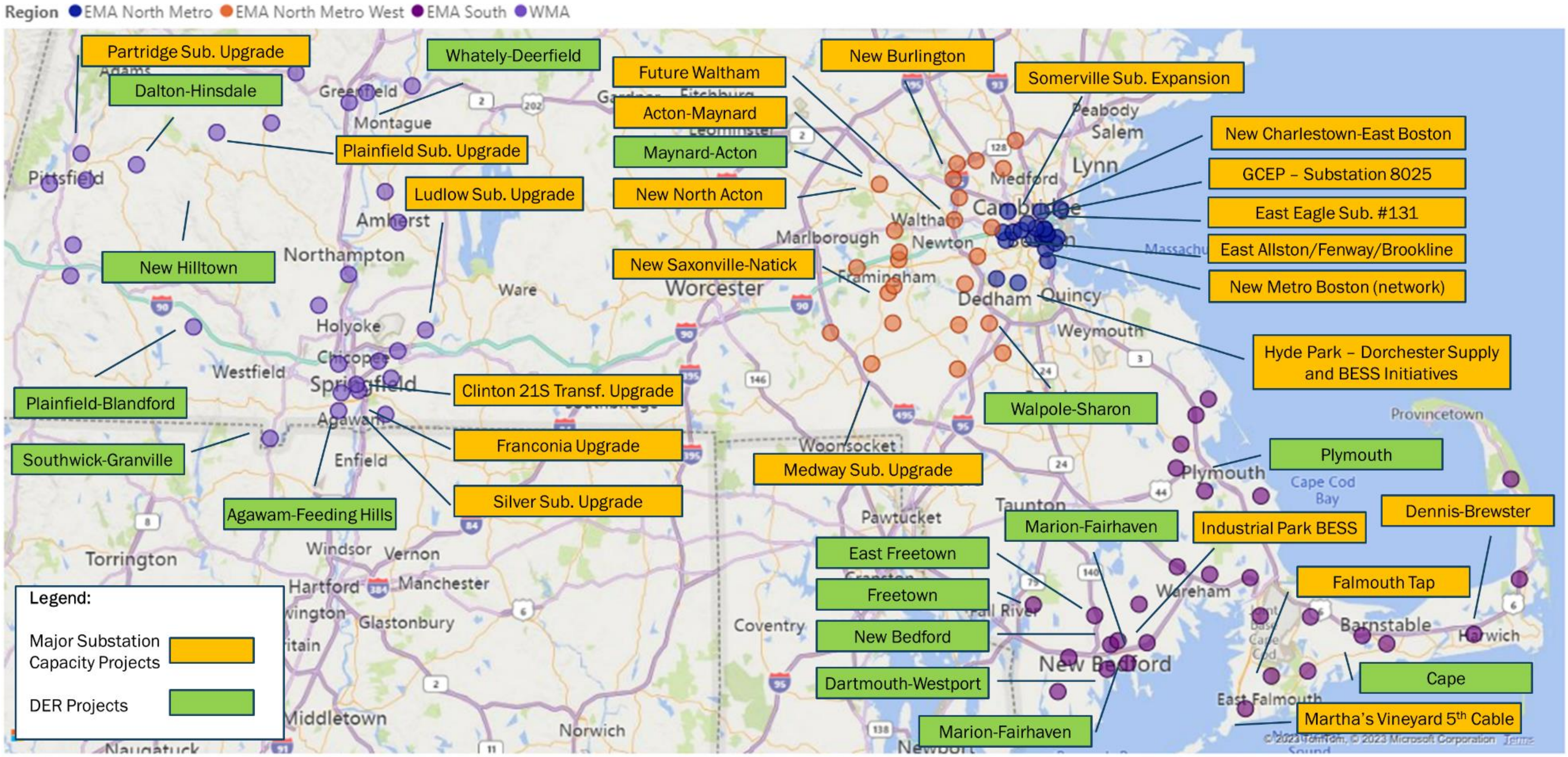


Figure 145: Location of Proposed and Approved Substation Upgrade Projects and CIPs in the Ten-Year Solution Plan

6.1.1. Overview of the D.P.U. 22-22 Rate Case

On November 30, 2022, the Department approved an increase in the Company's base distribution rates effective on January 1, 2023. In its approval, the Department authorized a continuation of the Company's performance-based ratemaking (PBR) plan for a five-year term with the possibility of a five-year extension. The Department discussed the basis for continuation of the Company's PBR plan and the need to provide sufficient resources for the Company to meet future statutory obligations, operational requirements, and customer expectations. The Department found that the PBR plan is better suited than other forms of rate making (including a comprehensive capital cost recovery mechanism) to satisfy the Department's public policy goals, acknowledging investments included in its 10-year capital plan that are necessary to maintain reliability. Large bulk substation projects were discussed during this proceeding as part of necessary investments included within the capital plan. The bulk substation projects discussed are necessary to enable electrification and maintain safe and reliable service. Within the five-year rate case period ending 2028, the Company has included capital investments for major projects slated to be in-service by 2028 as well as investments incurred for major projects slated to be in-service beyond 2028. The capital investments associated with all approved investments are included in the blue colored bars in Section 7. However, a more granular view of specific large bulk substation projects along with their respective required in-service years represented in three five-year tranches is documented in Figure 144.

In the ten-year period from 2025-2034, significant investments in bulk substations and distribution capacity upgrades are needed, as described within this ESMP filing. While Eversource believes its approved cost recovery mechanisms are sufficient at the time of this filing, the Company welcomes meaningful stakeholder feedback on the underlying need, alternatives, siting and permitting issues, community outreach, and stakeholder process to ensure solution design and implementation of these major infrastructure projects is inclusive and incorporates Environmental Justice and Equity concerns brought by stakeholders as these projects progress in their lifecycle. However, near-term solutions in the five-year plan (2025-2029) which are urgently needed to meet existing or emergent capacity/reliability deficits, may afford less opportunity for stakeholder engagement at this stage than projects in the outer years (2030-2024 and beyond). Additional information on the projects in each region is included in Sections 6.5 through 6.8 of this ESMP.

6.1.2. Overview of the 2022-2025 Grid Modernization Plan (D.P.U. 21-80)

On October 7, 2022 and November 30, 2022, the Department issued its orders authorizing the Company's "2022-2025 Grid Modernization Plan" for (1) previously deployed technologies and (2) new technologies, respectively. The following provides an overview of the investments highlighted in the Company's 2022-2025 Grid Modernization Plan filing.

The Company is currently investing in the following categories: (1) Advanced Distribution Management System ("ADMS"); (2) Communications Network; (3) Monitoring and Control; (4) Volt VAR Optimization ("VVO"); (5) Advanced Load Flow; (6) Distributed Energy Management System ("DERMS"); and (7) Measurement, Verification and Support.

The ADMS investment is completing the implementation of the Distribution Management System ("DMS") project. The Communication investments consist of improvements to the Company's Field Area Network ("FAN") and modernization of data transmission infrastructure. The Monitoring and Control investments include substation relay upgrades and power quality monitoring. The VVO program includes the deployment of the technology in western Massachusetts and add advanced inverter control. The Advanced Load Flow programs include interconnection automation, probabilistic power flow modeling, and foundational investments in data analytics. DERMS investments establish a technology capable of dispatching DER on real time conditions as modeled by the DMS. The Measurement, Verification and Support investments will provide for on-going operational system support and maintenance, program management, and third-party measurement and verification.

In addition, the Company is deploying Advanced Metering Infrastructure (AMI) which will provide benefits and meet the changing needs of customers and establish an additional foundation for the Company to continue to modernize its distribution system. See Section 6.3.1 below for additional details on these investments.

6.1.3. Overview Cost Allocation Methodology and Approved/Submitted CIPs

Solar growth, especially large ground mounted solar, is critical to achieving the Commonwealth's net-zero carbon emissions goal by goal by 2050.[121] Over the past decade, Eversource saw solar distributed generation (DG) grow from essentially zero to about 1.6 GW. As this solar growth occurred, especially in Western and Southeastern sub-regions, available hosting capacity rapidly diminished, eventually stagnating the solar interconnection queue as developers were faced with the cost of rebuilding or expanding large bulk substations. In these areas of medium to high DG penetration, the standard approach to determining interconnection requirements and assigning costs based on a cost causation principle resulted in solutions and costs that prohibit new DG facilities from interconnecting, and effectively stalled DG development in the region. To improve the electric power system's (EPS) ability to support the Commonwealth's 2050 decarbonization goals, while ensuring safe and reliable electric service

[121] Massachusetts Executive Office of Energy and Environmental Affairs. "2050 Clean Energy and Climate Plan." Mass.gov, Commonwealth of Massachusetts, 2020, https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.

for all customers, it became necessary to explore new methods and policies for interconnecting large DG installations.[122]

Recognizing the need to address this problem, the Department, in November 2021, issued its Order in D.P.U. 20-75-B, Order on Provisional System Planning Program ("Order").[123] The Order established a new, provisional framework for planning and funding essential upgrades to the EPS to foster timely and cost-effective development and interconnection of DG. The provisional framework allowed the electric distribution companies to file certain EPS infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities. Under the provisional design, Eversource would fund the initial construction of these EPS upgrades for the portion of upgrade costs not paid for by interconnecting customers in queue, and would recover the annual costs of such upgrades from distribution customers. Over time, as future DG facilities interconnect to that CIP area and pay the corresponding CIP fee, the costs paid for by distribution customers will decline. These fees are specific to the CIP area which is an electrical area with inter-dependent substations specifically interconnecting the applicable DERs. Additionally, a portion of the costs of the EPS upgrades commensurate with demonstrated operational reliability benefits, are allocated to distribution customers.

Under the framework of this new provisional program, Eversource identified geographic areas that experience high DG penetration or are expected to saturate due to existing and in-queue DG.[124] These areas are shown in Figure 146 below. Distribution bulk substations and associated distribution circuits in these areas were assigned to a DG study group based on physical location, topology, load transfer capability, reliability, and capacity dependency with nearby substations. Based on this initial study, the Company was able to develop innovative and comprehensive solutions for all seven affected groups of substations in the Southeastern and Western areas of Massachusetts:[125] Marion-Fairhaven, Plymouth, Cape Cod, Freetown, Dartmouth-Westport, New Bedford, and Plainfield-Blandford.

[122] D.P.U. 22-47 Marion-Fairhaven Order dated December 30, 2022, at Page 3
[123] D.P.U. 20-75-B Order on Provisional Planning Program, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14232299
[124] A Provisional Program DG group is said to be saturated if the amount of DG at any of the substations limits the availability of permanent, unplanned, or scheduled system reconfigurations required for maintaining the operational flexibility of the system which determines reliability for all customers served by the substations.
[125] Provisional System Planning Program Guide." Mass.gov, Commonwealth of Massachusetts, https://www.mass.gov/guides/provisional-system-planning-program-guide.

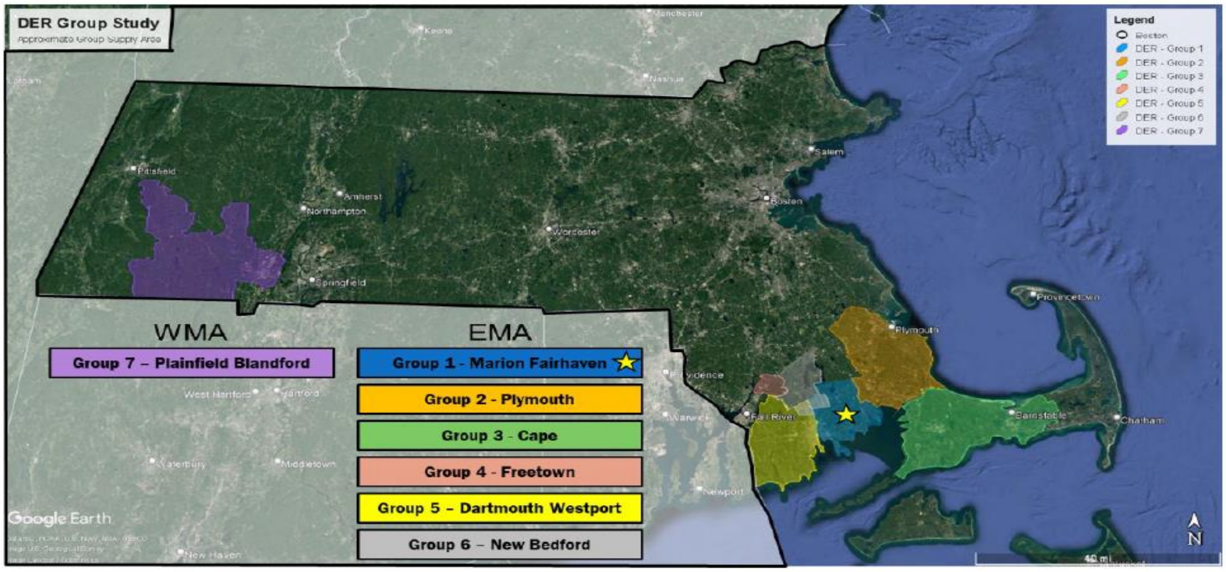


Figure 146: Provisional Program Group Study Regions

6.1.3.1 Provisional Program Group Studies and CIPs

Eversource integrates transmission planning, distribution planning, DER planning, reliability and resiliency planning, and advance forecasting and modeling into a cohesive unit. This integrated planning organizational structure allows the Company to efficiently perform many complex distribution and transmission studies in a relatively short timeframe and to analyze the interconnection requirements for approximately 342 MW of DG across 24 distribution bulk substations in the seven DG groups. The output of this analysis is a set of engineering designs and cost estimates for comprehensive solutions.

The provisional program framework allows the EDCs to file CIP proposals with the Department for projects that meet specific eligibility criteria.[126] Eversource submitted CIP proposals for six out of the seven DG group studies – excluding the New Bedford group since it did not meet the minimum requirements.[127] Table 40: Overview of the Provisional Program Groups shows an overview of the provisional program groups.

Table 40: Overview of the Provisional Program Groups

Group (CIP Docket)	Number of Substations	Existing DG (MW)	Provisional Program DG (MW)	Enabled DG (MW)
Freetown (DPU 22-51)	1	13	22	52

[126] Provisional System Planning Summary." Mass.gov, Commonwealth of Massachusetts https://www.mass.gov/doc/provisional-system-planning-summary-0/download

[127] The New Bedford group CIP fee exceeded the $500/kW threshold set in the 20-75-B Order

Group (CIP Docket)	Number of Substations	Existing DG (MW)	Provisional Program DG (MW)	Enabled DG (MW)
Plainfield-Blandford (DPU 22-52)	1	38	13	40
Plymouth (DPU 22-54)	7	237	123	380
Cape (DPU 22-55)	8	149	71	296
Marion-Fairhaven (DPU 22-47)	4	69	49	140
Dartmouth-Westport (DPU 22-53)	2	72	16	60
New Bedford (Not Filed)	1	58	48	72
Total	24	636	342	1,040

For each of the DG applications, the Company performed complex distribution and transmission studies to analyze the interconnection requirements in the seven DG group study areas. The System Impact Studies (SIS) included steady-state and dynamic analyses to identify:

- Thermal loading and voltage regulation issues due to DG output and battery operation
- Voltage flicker concerns and excessive movements of voltage control equipment due to variable output PV plants
- Short circuit current duty that would exceed equipment withstand capability
- Risk of unintentional islanding due to PV energizing a portion of the EPS
- Load rejection overvoltage and ground fault over voltage phenomena leading to transient over-voltage issues.

Following completion of these analyses, solutions to specific planning criteria violations were tested by the Company's engineering team. These included upgrades to transformers and lines, and/or new equipment to allow DG to safely interconnect and operate reliably. The final reinforcements that were proposed, adequately addressed capacity, stability, voltage, and reliability constraints that could result from DG saturation. Detailed steady-state and transient analyses at this scale, which included many substations, feeders, and new DG installations, were achieved by the coordinated efforts of multiple planning groups.

Transmission planning engineers were able to use the proposed upgrades as the starting point for determining required transmission-level reinforcements. The transmission assessments also included robust Electromagnetic Transient (EMT) analysis to not only ascertain whether the DG under study resulted in adverse impacts to the transmission system, but also provided a means to benchmark and validate each individual vendor-specific DG inverter model.

In summary, Eversource's integrated planning structure allowed for the development of a holistic solution, from the distribution feeder-level to individual substations, to aggregated groups of substations, to the transmission network. This planning all used the same sets of tools, data and personnel for steady state and dynamic analyses.

6.1.3.2 Provisional Program Cost Allocation methodology

Although the Provisional Program provided a potential pathway for many solar and Energy Storage System projects (ESS), it still required an innovative approach for funding essential EPS upgrades required to integrate DG in saturated areas of the distribution system. Eversource's engineering team proposed a new cost allocation methodology based on a capacity allocation principle[128] consistent with supporting regional climate change goals and leading the industry in sustainability. This innovative cost structure allocates infrastructure upgrade costs between interconnecting DG customers and distribution customers in proportion to the load and capacity enabled for each during the DG group study, based on actual connected MVA capacity.

Because the group study analyzes all DG customers holistically to evaluate the need to build common capacity to maintain safe and reliable operation of the EPS, the proposed solution is building the transmission and distribution infrastructure necessary to enable clean energy future to its customer and communities. These solutions benefit not just the DER developers, but also distribution customers supplied by these same reinforced distribution substations and feeders.

Eversource's capacity allocation structure, which accounts for existing and Provisional Program DG, future enabled small DG,[129] future enabled large DG,[130] and operational switching capacity, is defined below:

a) The operational flexibility, required to maintain the reliability of the overall distribution system, is subtracted from the total connected capacity created by the Provisional program holistic solution and categorized as a distribution customer benefit.
b) Existing small DG, enabled small DG, and existing large DG is subtracted from the available DG capacity, this value is smaller than the total connected capacity. Capacity reserved for future enabled small DG typically benefits residential DG facilities that connect under the Simplified Process[131]. Under the Eversource proposal, capacity reserved for small DG was categorized as a *distribution customer benefit*.
c) All the capacity remaining is the enabled large DG capacity which includes Provisional Program DG and future large DG reserved". Because enabled large DG capacity is allocated

[128] In D.P.U. 19-55, stakeholders submitted several proposals with alternatives to the Cost Causation Principle in response to the Department's solicitations. Refer to D.P.U 20-75 Vote and Order Opening Investigation dated October 22, 2022.
[129] Typically rooftop DG, less than 15 kW on single-phase or less than 25 kW on three-phase, utilizing the Simplified interconnection process
[130] Typically ground-mounted DG, greater than 25 kW, utilizing the Expedited or Standard interconnection process
[131] Refer to D.P.U. 20-75, Att. A – Page 10

at the substation level, it is possible to assess which interconnecting DG facilities are direct beneficiaries of this reserved capacity. Therefore, this capacity will be assessed by the Company to an interconnecting large DG customer.

By allocating all the capacity created by the group study comprehensive solution in the above format, a systematic approach was developed to calculate a distribution cost per MW for each provisional program DER group (D.P.U 22-47, and DPU 22-51 to 22-55). This cost per MW was applied to all DG customers, both in queue and future. As an example, by multiplying the total substation and distribution line costs by the ratio of the created large DG capacity, over the total created capacity by the provisional program solution, a final cost per MW ($/MW) can be derived and applied to each large DG facility as shown in the expression below:

$$Large\ DG\ Customers\ Cost\ Allocation = \frac{Large\ DG\ Capacity}{Large\ DG\ Capcity + Operational\ Capacity + Future\ Small\ DG} * (Solution\ Cost)$$

Finally, the same principle can be used for each of the Provisional Program groups and to determine the cost allocated to distribution Customers.

On April 15, 2022, Eversource submitted a CIP proposal with the innovative cost allocation methodology for the Marion-Fairhaven group to the Department for review and approval in docket D.P.U 22-47.[132] Subsequently, on April 29th of 2022, Eversource submitted similar CIP proposals for the other five groups to the Department for review and approval in dockets D.P.U 22-51 to D.P.U. 22-55.[133]

On December 30th, 2022, the Department approved the ground-breaking Marion-Fairhaven CIP, directing the Company to comply with directives as contained in the Order.[134] The five other CIP proposals in dockets D.P.U. 22-51 to D.P.U. 22-55 are still pending approval with the Department.

6.1.3.3 Updates to Group Study Approach and Cost Allocation Methodology

Based on the success of the provisional program in developing comprehensive solutions to allow more DG to be successfully integrated into the system, Eversource has adopted the DG group study methodology as a mechanism for addressing the backlog of DG projects in the

[132] D.P.U 22-47 Initial testimony dated April 15, 2022 and revised May 2, 2022. (Exhibit ES-Engineering Panel-1 (Marion-Fairhaven)(Revised)

[133] D.P.U 22-51-55 Testimony dated April 29, 2022. (Exhibit ES-Engineering Panel-1 (Freetown (D.PU. 22-51), Plainfield-Blandford (D.P.U. 22-52), Dartmouth-Westport (D.P.U. 22-53), Plymouth (D.P.U. 22-54), Cape (D.P.U. 22-55))

[134] Refer to: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827728 - Order by Chair Nelson, Commissioners Hayden and Fraser dated 12/30/22

state. Since filing the CIP proposals, the Company has taken steps to improve how it develops group study solutions and how costs are allocated.

One of the requirements of the Provisional Program was that the group study solution should specifically be designed for the Provisional Program DER. In-queue DER and future DER growth were not explicitly considered in determining the solution, and area electrification needs was also not a solution driver. As discussed in the testimony and interrogatory responses for each of the previous six CIPs, the ability of the group study to meet electrification needs in each CIP area, based on the Commonwealth's 2050 goals, was determined after the fact (post-process). In many cases, the CIP solution did not enable the full projected electrification demand. Recognizing this deficiency, the Company has taken an integrated planning approach to developing the group study solution, based on current and future DER integration needs as well as load forecasts and electrification demand projections.

Low DER Saturation Area

In areas of low DER penetration, substations and circuits can typically be analyzed independently and not as part of an interconnected, inter-dependent group. This is because, even though substations might still have N-1 dependency, the DER penetration has not reached the critical point of affecting the reliability and operational flexibility of the larger EPS. Individual and nearby substations are not saturated to the point of restricting permanent, emergency, and planned system reconfigurations. The low DER penetration scenario is illustrated in Figure 147 below. In this scenario, circuit 1 provides transfer capability between substations A and C, circuit 2 provides transfer capability between substations C and D, and circuit 3 provides transfer capability between substations B and D. Circuit 4 provides transfer capability to offload circuit 1 and circuit 3. In this scenario, reliability and operational flexibility are not affected because system reconfigurations under contingency conditions do not result in adverse conditions (thermal issues, steady-state or transient voltage violations) at individual substations or adjacent substations. Moreover, each substation can be analyzed independently to determine the trigger points for upgrades required to accommodate future DER, i.e., cost causation can be easily determined when looking at individual substations within this static system.

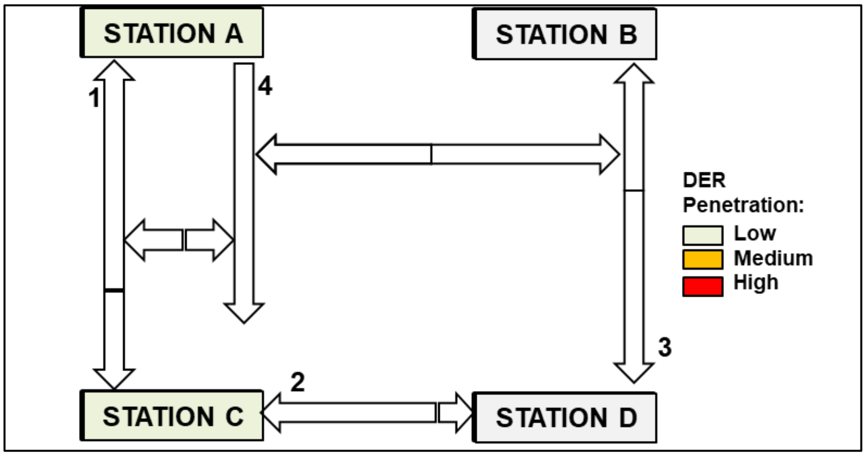


Figure 147: Low DER Penetration Scenario

<u>Medium/High DER Saturation Area</u>

A high DER penetration scenario is depicted in Figure 148 below. In this scenario both Substations B and C are expected to have high DER penetration (or saturation) which affects the system reconfiguration capability between substations A and B, A and C, B and D, and C and D. Moreover, reconfiguration options that were previously available between circuits 1 and 4 and 4 and 3 could also be limited depending on the amount and location of new DER connected to the circuits. Not only are Substations B and C saturated, but this condition may also result in saturation at Substations A and D since transfer capability that was previously available via circuits 1, 3, and 4 is now limited due to saturation at substations B and C. This is because under scheduled or forced outage conditions, the station tie-lines that traditionally help boost station load carrying capability (LCC), serve as conduits to transfer additional DER (more than load) to neighboring stations.

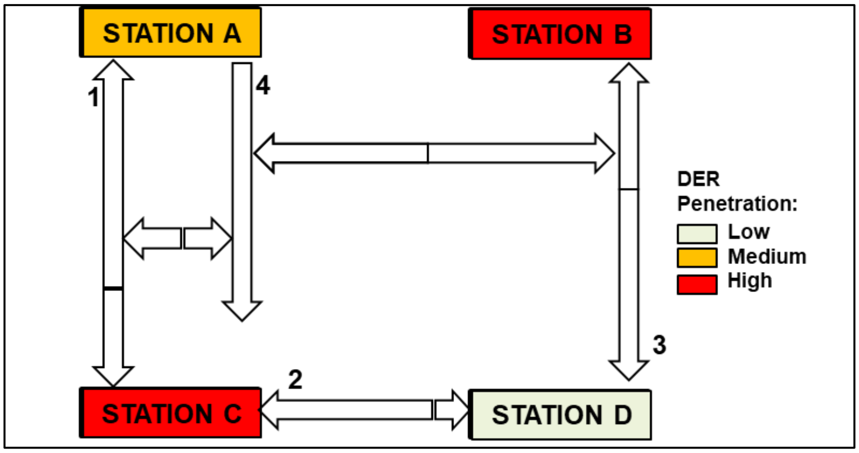


Figure 148: Medium to High DER Penetration Scenario

In areas of medium to high DER penetration, substations that rely on each other for support during N-1 contingency events must be analyzed as a group to find the most cost-effective solution that integrates new DER while maintaining the current level of reliability and operational flexibility for the EPS. In this scenario, the standard approach of analyzing individual substations used for areas of low DER penetration, has the potential of increasing cost, reducing reliability, and limiting operational flexibility. For example, even if upgrades are completed at substation B and C to reduce the negative effects of increased DER penetration at those stations, this could still result in saturation at substation A and D by limiting the transfer capability between substations A and C, B and C, and C and D along with circuits 3 and 4. . A group study approach analyzes the group holistically to determine the most cost-effective solution for all substations in the group and to evaluate the need to reserve or build capacity to maintain safe, reliable operation of the EPS.

Similarly, Figure 149 below, illustrates some of the operational challenges that can result at the distribution feeder level in areas of medium to high DER penetration. The left side graphic shows the existing "as is" system under normal (N-0) conditions where three of the four substations are already at medium-level DER saturation.

The right side shows a potential scenario in which substation A saturates due to reliability improvement work at the distribution feeder level. The work could consist of transferring a section of a circuit from circuit 3 to circuit 4, a common practice used to balance load or customer count between the two circuits or substations or to reduce exposure for customers on a poor performing circuit. In this scenario, depending on the ratio of DER to load on the section, transferring both load and DER from circuit 3 to circuit 4 might be constrained unless a significant amount of reinforcement work is completed on both circuit 4 and substation A. This "constrained" condition that results from having a system at high saturation levels limits the flexibility of operators during normal and emergency conditions.

Moreover, the constrained condition also limits the ability of planners and engineers to propose system design changes that will improve the performance of the EPS and enhance service to existing distribution customers. Utilities faced with significant DER growth, without the ability to address these types of conditions, could experience reliability deficiencies in the near-term when low DER saturation areas progress to medium or high saturation. DERs could be forced offline for long periods to facilitate any scheduled work at these stations as well as under forced (unplanned) bulk substation outage scenarios. In addition to the substation reliability benefits to all customers, new distribution lines and line upgrades driven by DER growth are likely to create opportunities to rebalance feeders, reduce exposure and transfer load, which would lead to improved reliability and voltage quality for distribution customers.

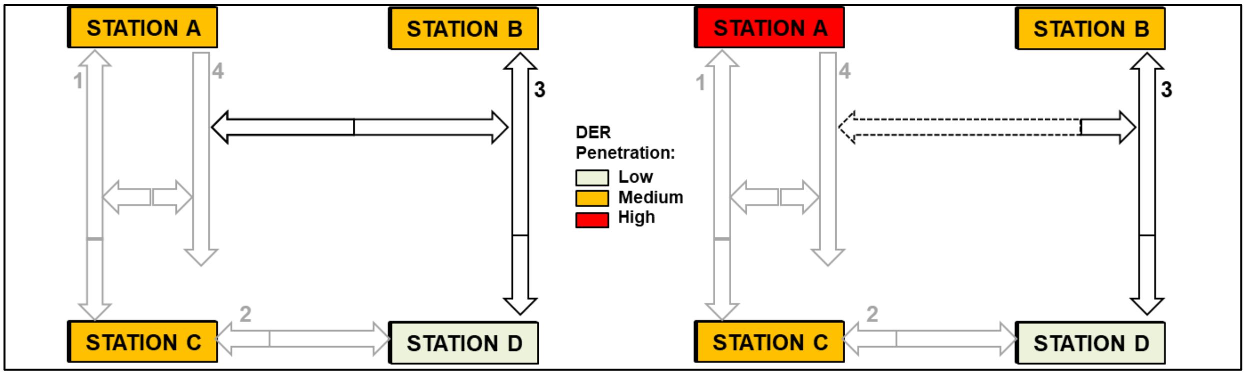


Figure 149: Operational Challenges at Distribution Feeder Level

Proposed Group Studies

Based on these concepts, the Company identified several areas of the system where integrated planning studies could be conducted on groups of DER interconnecting at one or more substations. For each area, the Company assessed the inter-dependency with nearby substations, based on the design of the substations (one or more transformers), the geographical distance between the substations, the presence of feeder ties, and the contribution of tie feeder capacity to the substation LCC rating. The following seven groups were identified from this analysis (described later in Sections 6.6.1, 6.7.1, 6.8.1):

- East Freetown in EMA-South
- Maynard-Acton in EMA-North Metro West
- Walpole-Sharon in EMA-North Metro West
- Whately-Deerfield in WMA
- Southwick-Granville in WMA
- Agawam-Feeding Hills in WMA
- Dalton-Hinsdale in WMA.

For each of these groups, the Company determined:

1. Existing ground-mounted (large) and rooftop (small) DER
2. Group study DER or the in-queue DER that would be studied as a group for interconnection
3. DER in-queue after the group study DER
4. Potential for future DER growth based on historical trend and technically developable land in the group study substation area
5. Ten-year maximum and minimum load forecast for group substations
6. Twenty-year demand forecast accounting for electrification growth in the area
7. Currently installed capacity for group study substations.

Once the existing and future DER are determined for each study group as well as the projected area capacity and reliability needs, the Company determines the suite of upgrades required to accommodate the existing and future DER interconnections and meet future electrification capacity and reliability needs. Future transmission, substation and distribution line reinforcements are determined after completion of detailed load flow, dynamic and transient analyses that account for equipment firm capacity and emergency transfer capabilities. Final reinforcements would result from detailed analyses accounting for capacity, stability, voltage, and reliability constrained conditions that could result from DER saturation.

The Company determines the cost allocation and resulting CIP fee based on the Capacity Allocation concept described in previously filed testimony for Marion-Fairhaven (D.P.U 22-47[135]) and the other five CIPS (D.P.U 22-51 to D.P.U. 22-55[136]), but with adjustments made for the *ten-year forecasted load*,[137] instead of current load. This capacity allocation structure is the basis for Eversource's CIP proposal, including customer benefit allocation. Under this proposed structure, capacity allocation is prioritized as follows:

a) The "Reserved Operational Capacity[138]" is subtracted from the "Installed Capacity - Group Solution." This remaining Capacity is the "Reserved DER Capacity".
b) "Existing Ground Mounted DER", "Existing Rooftop DER", "Enabled Rooftop DER Capacity[139]" are then netted out of "Ten-Year Minimum Gross Load[140]" and then subtracted from "Reserved DER Capacity" to derive "Enabled Ground Mounted DER Capacity".

Lastly, Reserved Operational Capacity and Enabled Electrification are considered a mutually inclusive Distribution Customer Benefit. At the substation level, capacity is reserved for Operational Flexibility, of which a portion of incremental capacity for each CIP would be utilized to reliably enable electrification.

---

[135] D.P.U 22-47 Initial testimony dated April 15, 2022 and revised May 2, 2022. (Exhibit ES-Engineering Panel-1 (Marion-Fairhaven)(Revised)

[136] D.P.U 22-51-55 Testimony dated April 29, 2022. (Exhibit ES-Engineering Panel-1 (Freetown (D.P.U. 22-51), Plainfield-Blandford (D.P.U. 22-52), Dartmouth-Westport (D.P.U. 22-53), Plymouth (DPU 22-54), Cape (D.P.U. 22-55))

[137] The ten-year forecasted load is used in this updated cost allocation methodology to account for the fact that load growth within the ten-year forecast window will reduce the future enabled electrification.

[138] At the substation level, Reserved Operational Capacity is driven by the Operational Capacity of the substation based on the MVA capacity of the remaining transformer(s) assuming the largest transformers is off service. For example, for a substation with two equal sized transformers, the Reserved Operational capacity is 50% of the total connected MVA capacity. For a one-transformer substation(s) the Reserved Operational Capacity is zero, but 5% of the connected MVA capacity is used for capacity planning purposes.

[139] To forecast the Enabled Rooftop DER AC capacity value, the historical adoption rate per station, as well as distribution sizing were considered as inputs into a probabilistic model. The results of the analysis are in line with the MA decarbonization roadmap projections from 2030, doubling the installed capacity to 2030.

[140] For planning purpose, when analyzing DER, Eversource considers periods of light distribution load and high DER penetration. Distribution customer load, to a limit, acts as an offset to DER because it helps reduce the system capacity constraints created by high DER output. Because of this, the Ten-Year Minimum Gross Load is considered an offset to DER and used in the calculation of additional Enabled DER capacity.

6.1.3.4 Proposed Actions

1) While the Company is waiting for approval of the other five CIPs, the Company has updated its group study approach and cost allocation methodology to account for future planning considerations (which were explicitly prohibited in the Provisional Planning Program). The updated approach considers enablement of standalone battery storage, electrification, and future load growth. The Company is prepared to refile any of the CIPs that might be rejected with the updated cost allocation methodology.

2) The Company has performed a group study and developed a comprehensive solution for the East Freetown area in SEMA (which includes the DERs that were originally in the New Bedford group study, not filed with the other CIPs). This solution includes a new station near the existing Industrial Park station which will absorb most of the DER originally proposed in the group, DER in queue, future DER in the area, as well as and some existing DER and load from Industrial Park. The CIP for the new station solution, East Freetown, is described in Section 6.7.1. The solution and CIP fee for this group were developed using the updated approach.

3) The Company is currently developing a group study solution for 86 MW of DG applications in the Whately-Deerfield area of its Western MA territory. The proposed solution is a new substation and upgrades to existing stations and distribution feeders to safely and reliably accommodate the DER. The CIP for the group solution is described in Section 6.8.1. The solution and CIP fee for this group are developed using the updated approach.

4) Between June and August 2023, the Company announced that it is conducting five new group studies. These include the Acton-Maynard and Walpole-Sharon groups are in EMA-North Metro West and Southwick-Granville, Agawam-Feeding Hills and Dalton-Hinsdale areas are in Western MA. The notices to form the new group were posted on the Eversource website and in the Power Clerk portal. The open window for the applicants were initiated per the D.P.U. 17-164 Tariff provisions. The group studies are expected to be completed in the first quarter of 2024, and the solution and CIP fee for these groups will be developed using the updated approach. These groups are further discussed in Section 6.6.1 and Section 6.8.1.

Eversource's novel cost allocation construct helps 1) eliminate queue free rider issues, 2) establish a geographically unique fixed interconnection fee for twenty years in synch with the electrical design in that location, 3) establish a fixed schedule for construction of the upgrades, and 4) increase distribution capacity which improves reliability and load carrying capability.

This unique construct is a fundamental shift away from a pure cost causation model – which directly allocates all costs to interconnecting DER customers even though the same EPS upgrades are immensely beneficial to distribution load customers – aside from enablement of clean energy which also ultimately benefits all distribution customers. This kind of thought leadership is what the Commonwealth needs to significantly scale solar growth, while also staying grounded on upgrade design and costs unique to different sub-regions and associated DER customer costs and benefits.

6.1.4. Overview Energy Efficiency Programs

Eversource, along with the other Mass Save Program Administrators (PAs),[14] runs nation-leading energy efficiency programs, as authorized by the Green Communities Act (GCA).[15] The GCA mandates that the PAs develop three-year energy efficiency plans that will "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." For over 15 years, Massachusetts has been nationally recognized as a leader in implementing high-quality Energy Efficiency Programs. Massachusetts has consistently ranked first or second in the nation on the American Council for an Energy Efficient Economy's State Energy Efficiency Scorecard, and Eversource has received the top utility score[141]. These EE investments have resulted in substantial reductions in system-wide energy usage and peak demand, reducing summer peak load by as much as 100 MW annually. However, over the last few years, changing market dynamics have decreased the amount of electric savings that can be achieved with traditional energy efficiency programs. In particular, the transformational savings created by LED lighting technology has largely been exhausted, and sockets have become saturated with LEDs. LED technology was unique in that it allowed 70-80% reduction in energy usage as compared to the baseline technology, at relatively low incremental cost; most energy efficiency technologies, by contrast, create a 10-20% savings compared to baseline, with sometimes significant cost and greater complexity in installation. As a result, in Eversource's 2022-2024 Mass Save efficiency plan[142], total passive peak load reduction is anticipated to only be around 20 MW per year.

This reduction in achievable kWh and kW savings, however, does not indicate a reduced focus on energy efficiency. Rather, energy efficiency remains a critical first step on any customer's decarbonization journey and a cornerstone of the Mass Save programs, and Eversource is committed to enabling all customers to undertake the deep retrofits necessary for the clean energy future. The Company has made equity one of the key strategic priorities of the 2022-2024 Plan. Equity is defined in the Plan as the process of establishing more equal access to and participation in energy efficiency, particularly among those groups who have historically participated at lower rates, including renters/landlords, moderate-income customers, English-isolated families, and microbusinesses. Across all sectors, the Mass Save PAs are working to increase participation among these groups by researching and deploying the most effective

---

[141] 2023 Utility Energy Efficiency Scorecard, ACEE, n.d. https://www.aceee.org/research-report/u2304

[142] Exhibit 1: Three-Year Plan 2022-2024." MA EEAC, 1 Nov. 2021, ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf.

strategies to engage these customers, including through increased collaboration with community partners, enhanced incentives, improved language access, and targeted messaging. The 2022-2024 Plan reflects the general premise that energy efficiency does not stand in isolation, but is intimately connected to other Commonwealth policy goals, including GHG emissions reductions and increasing equity, and adopts a more nuanced and broader definition of success than previous Three-Year Plans. Eversource expects that this legacy of innovation and improvement will continue over the next decade, as they and other stakeholders are continuously looking to raise the bar to deliver sustainable and equitable energy savings, GHG emissions reductions, and benefits to customers, stakeholders, and the Commonwealth.

6.1.5. Overview Heating Incentive Programs

As described in the 2022-2024 Mass Save Energy Efficiency Plan, following the passage of An Act Creating A Next-Generation Roadmap For Massachusetts Climate Policy (the "Climate Act")[143], the Program Administrators (PAs) have engaged in an intensive effort to promote building end-use electrification, particularly in instances in which customer economics and building characteristics (e.g., displacement of delivered fuels or in specific new construction scenarios) favor the use of high-efficiency heat pump technologies.

The building sector is the state's second-largest source of GHG emissions, and therefore, any plan to mitigate GHG emissions must include a pathway for decarbonizing space and water heating. In addition to offering substantial customer incentives to help defray the up-front capital cost of electrification, the PAs are working with manufacturers and installation contractors to increase their confidence, comfort, and capability in proposing and installing efficient electric heat and water heating. These strategies will help boost the pace of electrification in the short term, while also creating an environment for a larger market transformation over time, a transformation necessary to ensuring the state meets its 2030 and 2050 climate targets.

The Company notes that under the current programmatic construct, electric equipment incentives for customers currently using oil or propane are provided by the customer's EDC ("Electric Program Administrator"), while the electric equipment incentives for customers currently using gas are provided by the customer's LDC ("Gas Program Administrator"). While this dual construct has worked thus far, as electrification hosting capacity reduces and subsequently expands in areas where large bulk substation projects are planned within this ESMP submittal, significant increase in coordination with the EDCs supplying electric power to the newly electrified customers becomes critical.

---

[143] St. 2021, c. 8, Malegislature.gov, 2021, Chapter 8. https://malegislature.gov/Laws/SessionLaws/Acts/2021/Chapter8

The PAs anticipate that electrification support will continue to be a critical component of the Mass Save programs in the future, though the exact nature of the incentives will necessarily evolve as the market adapts.

6.1.6. Overview Electric Vehicle Charging and Make Ready Programs

With transportation being the largest contributing sector to GHG emissions in the Commonwealth (42% as of 2017)[144] and a significant source of pollutants that contribute to ground level ozone and other air pollution problems that adversely impact public health in the region, transportation electrification provides the opportunity to significantly reduce emissions in the short- and long-term, while also supporting Eversource's grid to enable a clean energy future.

The Commonwealth has ambitious goals for EV adoption and Eversource is focused on ensuring that customers can access EVs and EV charging as their needs change over time. The Company's goal is to create a future in Eversource's regions where clean transportation is universal and the environmental and public health benefits are shared by all the Company's customers and communities. Although the transition to net-zero GHG emissions will happen over multiple decades, the investments necessary to support Eversource's customers in this transition must begin immediately and be aggressive.

Through its EV programs, the Company will support the transition to a clean energy future by reducing the barriers for residents, site hosts, and fleet owners to adopt clean transportation choices while also providing the necessary support and resources for Eversource's diverse customers to adopt EVs. The Company will support the expansion of the EV market in Massachusetts to meet the State EV adoption goals by assisting electric customers as they install EV charging infrastructure at their properties, plan for future EV related investments, and manage EV charging load. This initiative includes customer programs to reduce cost of deploying EV charging, expand equitable access to chargers, and support increasing EV adoption.

The Eversource EV Phase II Program (approved in D.P.U. 21-90) is a comprehensive set of offerings designed to support the growth of electric vehicles in the Commonwealth of Massachusetts, providing incentives to support the deployment of electric vehicle charging stations in the residential, public and workplace, and fleet customer segments. The Phase II Program builds upon the Company's first Program[145] by providing offerings to meet the diverse

---

[144] Transportation Sector Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, MassGov, December 2020; https://www.mass.gov/doc/transportation-sector-technical-report

[145] The Company has completed the Phase I Program (D.P.U. 17-05), which supported the installation of approximately 2,200 charging ports, while also providing the electrical infrastructure to enable the installation of nearly 2,100 additional ports at commercial customer properties for public, workplace, and multi-unit dwelling use.

needs of all the Company's customers, building the infrastructure required to support statewide EV adoption, and helping to enable the Commonwealth's broader transition to a clean transportation future. Key elements of the Phase II EV program are:

- **Residential EV Charging Program:** provides rebates to customers to offset the cost of installing 240V wiring upgrades at their property for home EV charging, which is needed to support a residential Level 2 (L2) charger. Some customers will also be eligible to receive rebates on Electric Vehicle Supply Equipment (EVSE) purchases if they are enrolled in the low-income discount rate. This program is available to customers that reside in dwellings of one to four units. Customers who participate are then required to participate in the Company's managed charging program, once such a program is approved by the D.P.U. As electrification hosting capacity diminishes, this program may need to not only be expanded but also transition to be more locational to ensure manage charging programs are working in concert with large bulk substation upgrades – driving toward a more cohesive decarbonization plan.

The program also includes a turnkey installation service to support residents in environmental justice communities or are enrolled in the low-income discount rate. This program aims to provide the equipment and installation at no cost to the customer.

Together, the Residential EV Charging Program and the turnkey installation service are sized to support the installation of more than 16,000 charging ports.

- **Multi-Unit Dwelling (MUD) EV Charging Program:** provides rebates up to 100% of the cost of the utility side and customer side infrastructure for EVSE installations at residential properties with five or more units. Depending on customer, location, usage, and type of the EVSE, the program may rebate costs for the EVSE purchase and networking costs. This offering is sized to support the installation of more than 2,000 L2 charging ports.

The MUD EV Ready Site Plan offering is an additional offering for MUD customers with 20 or more units to receive a detailed plan on how to provide EV charging for their residents. These plans will include project sizing, cost estimates, evaluations of existing electrical infrastructure, and operational impacts of the installation. The Company aims to bring this offering to customers in the second half of 2023.

- **Public and Workplace EV Charging Program:** supports commercial, industrial, and governmental customers to install L2 and Direct-Current Fast Chargers (DCFC) for use by stakeholders of the host locations, such as customers, employees, and other visitors. The main offering is known as a Make-Ready offering, a program by which the Company rebates up to 100% of the cost of the utility side and customer side infrastructure for EVSE installations. Depending on customer, location, usage, and type of the EVSE, the program may rebate costs for the EVSE purchase and networking expenses. The purpose of the Make-Ready offerings is to lower the financial burden for customers who want to install EV charging infrastructure.

- **The Fleet EV Charging Program:** supports the installation of L2 charging stations to support customer light duty fleet electrification. This offering provides up to 100% of the cost of the utility side and customer side infrastructure for EVSE installations. Fleets owned by public entities, such as municipal governments, are eligible for rebates for EVSE. The program also offers a Fleet Assessment Service to provide a detailed plan and a roadmap for a public fleet customer to upgrade their fleet from internal combustion engine vehicles to EVs. The report includes analysis of estimated bill impact, projected operating costs, available vehicle models, proposed replacement schedule, procurement prices, future electrical demand against current capacity, and a high-level infrastructure upgrade scope.
- **Demand Charge Alternative:** this is an EV Pricing offering that is designed to support the adoption of EVs in the Commonwealth by reducing the impact of demand charges on low load factor EV charging sites. Rate EV-2 was introduced for charging stations greater than 100 kW. The rate design employs base distribution demand and energy charges on a sliding scale. As load factor increases, the demand charge increases, and the energy charge decreases. This offering is 10 years in duration from July 1, 2023 through June 30, 2033. All customers on G-2 or G-3 rates with separately metered EV load are eligible to participate. The demand charge discount will be based on the load factor threshold and will be assessed according to the below schedule:

Table 41: Demand Charge Discount Schedule

Load Factor Threshold	Enrollment Years	Demand Charge Discount
None	1	100%
LF <= 5%	2 to 9	100%
5% < LF <= 10%	2 to 9	75%
10% < LF <= 15%	2 to 9	50%
LF > 15%	2 to 9	0%

For stations less than or equal to 100 kW, Rate G-1 has been made available with a non-demand price option. This rate is not a limited program and does not employ demand charges regardless of load factor.

- **Managed charging programs:** With the forthcoming managed charging program proposal, the Company plans to offer both passive and active managed charging programs. Like economic signals provided through time-differentiated rates, the passive managed charging program will provide incentives to motivate customers to shift their charging to off-peak times. The Company views a passive managed charging program as a tool to bridge the gap until time-differentiated rates can be widely offered to residential customers. Familiarizing customers with the concept of paying attention to the times that they charge can lead to a more successful and seamless transition to a TOU rate once it is introduced. Additionally, a passive program allows customers to become comfortable with the idea of utility being aware of and involved with operations pertaining to their personal vehicle; a valuable foundation to establish that can enable more advanced charge management in the future. With the rollout AMI, the Company will gain the ability to offer time-differentiated rates which will reduce the need for a passive managed charging program. However, prior experience indicates that not all customers will respond to price signals. The Company expects active managed charging programs to remain crucial to enable charge management at a local level that cannot effectively be achieved through rates.

- **Commitment to equity:** A guiding principle of the Phase II Program is to ensure that the proposed EV offerings are implemented equitably. EVs present a tremendous opportunity to mitigate the GHG emissions and particulate matter that exist disproportionately in EJCs. The installation of EV infrastructure and enabling EV miles driven as well as coordinating grid upgrade plans necessary with public transit electrification plans within EJCs will provide increased access to clean transportation and promote public health. The Company recognizes that today, the upfront costs to EV adoption are high and that there is a need to tailor programs for EJCs and low-income customers, so they are not left behind in the transition to EVs.

To put this into practice, the Company's Phase II program includes two pilots focused on supporting customers in environmental justice communities.

  - The DC Fast Charger hub pilot program provides rebates up to 100% of the electrical infrastructure cost (both utility-side and customer-side of the meter) for the installation of DC Fast Chargers within communities where access to home charging may be limited. Customers installing chargers within this offering will also be eligible for EVSE and networking rebates.
  - The Medium- and Heavy- duty vehicle fleet pilot program provides rebates up to 100% of the electrical infrastructure (both utility-side and customer-side of the meter) for the installation of EV chargers to support medium- and heavy-duty vehicle fleets. This offering will be focused on fleets that either reside in or spend most of their time traveling through environmental justice communities.

○

Table 42: Overview of EJC and Low-Income Offerings

Public and Workplace	Increased Incentives • 100% make-ready costs and full rebate for all EVSE installed in EJCs • Network incentive ($480 / port) for all ports installed in EJCs Unique Offerings • Fully funded DC Fast Charging Hubs in EJCs Expectations • 40% of ports deployed in EJCs Targets • ~$38 million investment • ~2,400 Level 2 and DCFC ports
Residential	Increased Incentives • Make-ready and EVSE support of up to $1,700 for 1-unit properties (compared to $700 for non-EJCs) and up to $2,700 for 2-4-unit properties (compared to $1,400 for non-EJCs) • 100% make-ready costs and full rebate for EVSE installed at large MUDs in EJC • Network incentive ($480 / port) for all ports installed at large MUDs in EJCs Unique Offerings • Turnkey installation and increased financial support for LI/EJC to cover costs of residential make-ready and managed-charging capable L2 EVSE • EV Site Plans will help large MUDs (many of which are in EJCs) develop a plan for EVSE Targets • ~$25 million investment • ~7,500 Level 2 ports
Fleet	Increased Incentives • 100% make-ready costs and full rebate for EVSE for light duty fleets in EJCs Unique Offerings • 100% make-ready costs and EVSE rebate for MD-HD fleets that serve EJCs (part of Equity Pilots program) Expectations 40% of 150 private and non-profit Fleet Assessments conducted in EJCs Targets • $3 million investment in MD-HD EJC pilot

Other Offerings	Pilots to Increase Access to Electric Mobility in Environmental Justice Communities ("Equity Pilots") • 100% EVSE for fleets and workplaces that serve low-income communities

6.1.7. Overview of Community Solar Programs

6.1.7.1 Current Program

Solar Massachusetts Renewable Target (SMART)

In partnership with the DOER, Eversource operates the Commonwealth's primary solar incentive initiative, the Solar Massachusetts Renewable Target (SMART) program. Launched in 2018, this program was designed to serve as a lower-cost successor to the previous Solar Renewable Energy Certificate (SREC) programs. Under the SMART program, eligible customers and solar project owners receive monthly incentive payments from Eversource for the metered production of their solar installations. The program provides a long-term, fixed value incentive that builds on the Commonwealth's existing net metering incentive structure.

The SMART program was designed to support a broad variety of solar project types and ownership models. The program includes adders for community shared solar projects, solar on low-income affordable housing facilities, agrovoltaic projects, and solar canopies, amongst others. Implementation of the program by Eversource includes close coordination with the DOER as well as regulatory oversight by the DPU. To date, more than 26,000 solar projects totaling more than 750 MWdc have been installed under the SMART program in Eversource territory.

6.1.7.2 Potential Future Solar Program Offerings

Eversource shares the goal of the administration and Environmental Justice advocates that solar policies should be inclusive, accessible and that all ratepayers should be able to benefit from clean energy technologies. To that end, Eversource has proposed several solar initiatives that complement the Commonwealth's existing solar incentives. These initiatives are designed based on national best practices and Eversource's experience operating solar incentive programs across New England. Two of these efforts, the Community Solar Access Program and the Community Solar Resilience Program, are currently pending before the DPU while the third, the Affordable Solar Access Program (ASAP), would be proposed after Department approval of the Company's ESMP. Recognizing that the best programs are designed collaboratively with the groups most directly impacted and benefitting from them, each of Eversource's planned future programs were developed though robust stakeholder processes that include direct participation from income-eligible and environmental justice community members. Ultimately, the Company's proposed programs are intended to foster a solar market where every resident of the Commonwealth, regardless of their income has a solar option available to them. Each of these proposed programs is discussed further below.

Community Solar Access Program

In July 2021, Eversource filed a proposal for an Eversource Community Solar Access Program, or ECSAP, with the DPU. The intent of the program is to reduce barriers for income-eligible households to participate in community shared solar projects and encourage more development of SMART community shared Solar Tariff Generation Units by simplifying the billing and credit transfer processes experienced by system owners (Owners) and participating customers (Subscribers). The Program would provide a simplified billing structure for the distribution of Alternative On-Bill Credits (AOBC) that eliminates third-party bills between Owners and Subscribers. Instead of transferring AOBCs wholly from Owner to Subscriber accounts, the AOBCs would be automatically apportioned at a pre-determined percentage between on-bill credits issued directly to low-income Subscriber accounts and a direct cash payment to Owners. The Program would also establish an Eversource-administered low-income customer enrollment process to identify and enroll eligible low-income customers. If approved, the ECSAP would reduce identified barriers to community solar participation while lowering customer acquisition costs for project developers. The ECSAP would also eliminate consumer protection concerns as participating low-income customers would receive direct monetary benefits on their bills without any obligations to make payments to third party Owners. The Program proposal is currently pending approval with the DPU.

Community Solar Resilience Program

In June 2022, Eversource filed a proposal for a 2.1 MW solar facility with battery storage at its Area Work Center in Yarmouth. This proposal is part of a set of three projects filed in response to Section 77 of An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy (2021), which authorizes EDCs and LDCs to construct and operate solar facilities paired with battery storage where possible. During normal operations, when there are no outages, the proposed project would provide annual source of solar revenues to benefit low-income customers and residents of environmental justice communities within Yarmouth. During power outages, the project is designed to increase climate resiliency by providing clean backup power for the Area Work Center which provides emergency power restoration services to surrounding communities. Eversource has proposed a community engagement process that will engage local stakeholders in determining the best use of revenues derived from the solar and storage projects. The community outreach plan follows the principles of inclusivity and language access laid out in the Department's Draft Policy on Enhancing Public Awareness and Participation and the Company's Equity Framework described in D.P.U. 22-22. Eversource has committed to using a competitive procurement process to select the contractors involved in building the sites to minimize project costs. Eversource will also design the procurement process to maximize use of local and regional workforce, ensure that jobs created provide living wages, provide bid preferences to minority or women-owned businesses, and establish incentives for contractors to provide apprenticeship opportunities for local residents from EJCs. Eversource participated in evidentiary hearings regarding the project in August 2023.

Affordable Solar Access Program

Income-eligible customers and multifamily affordable housing property owners face unique barriers to installing on-site solar technologies and adoption amongst these customers has traditionally lagged the Commonwealth's otherwise robust solar market. Inclusive utility investment programs (aka. On-bill repayment tariffs) are incentive mechanisms intended to allow customers to pay off the costs of clean energy technologies on their utility bills while seeing net energy and bill savings from reduced grid electricity consumption. Properly designed programs can allow rental properties to easily install solar by tying incentive repayment to tenant meters, thereby overcoming landlord/tenant split incentive challenges. Further, programs designed to promote solar ownership instead of only providing customers with bill reductions can help build wealth in communities by allowing customers to invest in clean energy property improvements on their homes.

Eversource proposes that the Affordable Solar Access Program (ASAP) will operate in concert with the Commonwealth's existing solar incentive programs. Under the program, multifamily affordable housing landlords and income-eligible residents in owner-occupied properties would select a solar installer from a pre-vetted list of installers offering standard pricing. Like existing Solarize programs originally pioneered by the MassCEC, installers would be competitively selected through a community-advised RFP process. Once selected, installers would be required to sell and install projects with the highest consumer protection standards and associated production guarantees.

Solar project costs would be covered by an upfront payment from Eversource, meaning income-eligible and affordable housing customers would have no up-front costs to install solar. Participating customers would re-pay the initial investment via monthly on-bill charges. Eversource would seek to monetize all applicable additional incentives on behalf of the customer including Renewable Energy Certificates and, dependent on IRS rules, Investment Tax Credits. Monetizing these additional incentives on behalf of participating customers, while passing along their value through reduced monthly solar payments, will streamline and simplify solar installations for customers that may not otherwise be able to directly benefit from existing solar incentives.

While monthly payments from participating customers and monetization of available incentives are intended to cover the costs of the initial solar investment over time, to the extent any customer is unable to continue making solar payments, Eversource would seek to recover costs from all ratepayers, like how the cost for assistance programs such as the low-income discount rate are recovered today. Eversource proposes to offer ASAP initially in communities that host major new infrastructure upgrades. In this way, income eligible customers and multifamily affordable housing owners will be able to access and benefit from the new interconnection capacity created by Eversource's system investments. The incentive structure proposed here builds off the Commonwealth's successful Mass Solar Loan program which was sponsored by the MassCEC and DOER and resulted in thousands of income-eligible customers owning their own solar projects. This proposal could also provide a foundation for supporting solar projects should future federal funding become available through programs like DOE's Solar For All initiative.

6.1.8. Overview of Demand Response Programs

Eversource, along with the other Program Administrators (PAs) that deliver the Mass Save programs, offers comprehensive Active Demand Response programs to customers. These offerings incentivize brief reductions in customer load during targeted periods of high system demand. By generating these system load reductions, the PAs can influence the long-term forecast that ISO-NE uses to establish the Installed Capacity Requirement. As a result, all customers benefit from the lower costs of a smaller generation and transmission system. These peak demand reductions also provide immediate benefits to all customers in the form of suppressing wholesale power prices during times of high demand, by reducing the system's reliance on what would otherwise be the most economically and environmentally expensive forms of generation.

The PAs rely on system forecasts to predict which days are likely to be peak days, which hours are projected to be peak hours, and provide customers and curtailment system providers with day-ahead notifications prior to calling a dispatch event. In determining how often to call events, the PAs must balance the potential value of curtailment with the disruption that the event may cause for customers. If the PAs call too many events that adversely impact comfort or operations, then the PAs risk having customers opt out of events or unenroll from the program entirely. Since launching DR programs in 2019, the Company has gained experience with customers' response to 3-hour events called several days in a row during heat waves. The company has found that curtailment from large commercial and industrial customers can decrease as much as 13% day over day. For residential customers, higher event opt-outs for thermostats are more closely correlated with higher outdoor air temperature rather than being attributable to customer fatigue (events called on consecutive days). However, batteries, thermal storage, and some other types of equipment can lend themselves to repeated dispatch without substantially altering the comfort or operations of a customer's home or facility. These technologies are typically used in daily dispatch offerings because they can be called on many of the peak days during July and August with limited event fatigue.

The PAs' ADR offerings can be grouped into two main strategies for reducing demand during peak load events: (1) "device-specific" demand reduction strategies and (2) "metered" demand reduction strategies. While not intended to be exclusive to either sector, device-specific strategies are deployed more for residential customers and metered strategies tend to favor C&I customers.

Device-specific demand reduction strategies use connected device telemetry to temporarily adjust control settings in a way that results in lower demand during the event, such as smart thermostats, storage, and EVs. Because device-specific strategies rely on telemetry from the devices themselves to assess performance, these strategies do not require interval metering. This is especially important in Massachusetts as interval metering for residential customers and most C&I customers have not yet been approved and implementation of any future approvals will likely take several years, at a minimum.

A challenge with the device-specific approach is that the PAs cannot rely on access to a meter to assess performance; therefore, the PAs need to develop relationships with device manufacturers to implement curtailment offerings and receive data documenting participation and verifying performance. The PAs work with their Distributed Energy Resource Management System (DERMS) providers to integrate as many products as feasible, but some product manufacturers are not motivated to integrate with a DERMS, for a variety of potential reasons (see the section below for more details regarding DERMS).

"Metered" demand reduction strategies are aimed at customers with existing interval meters, or with enough load to justify the installation of third-party meters by curtailment service providers. This approach assesses the total reduction in facility load relative to a baseline that approximates the facility load if no demand reduction had occurred. The baseline methodology is aligned with how ISO-NE calculates their baseline for the FCM, and customers are provided with performance-based incentives which reflect the incremental curtailment the PAs were able to affect.

The Company expects responsive load to play an important role in management of the grid going forward, but at this time does not know exactly what future programs will look like, given the evolving technology in this space.

6.2. Design Criteria Changes

There are no changes to Eversource's distribution planning and design criteria. A description of existing standards and their application to capacity and reliability planning is included in Section 4.1.5.

6.3. Technology Platforms Eversource is Implementing

6.3.1. Description of Implementation Justification and Expected Benefits – Programs Currently Under Development

6.3.1.1 Advanced Distribution Management System (ADMS)

The ADMS project will provide operators with an as-operated electrical model of the entire distribution system. The model will be based on asset information from the Company's GIS and other asset databases. Direct integration with the Company's Energy Control System will incorporate telemetry and control capabilities from all substation and field devices. Integration with the Company's outage management system ("OMS") will ensure all information associated with the as-operated condition of the distribution system is available to support efficient restoration activities. Operators will transition from limited situational awareness and significant amounts of data to a tool that provides a mathematical model of the distribution system that will run real-time load flow calculations of the distribution grid based on electrical characteristics and measured values. These will then be used to assess system conditions against operating limits, including voltage limits and normal and emergency limits of cable and equipment.

Load flow calculations provide the current state of the system including voltages, currents, and power flow direction as well as warn of potential operating violations if another piece of equipment is lost. The same load flow can be used to model future state configurations which are useful for operational and long-term planning. The ADMS will have the ability to accept and process data more efficiently and effectively than human operators. With substation, feeder and other equipment alarms, conditional system limits, filtering and forecasting the ADMS will aid in avoiding the potential for information overload, allowing the Company to operate equipment with greater efficiency and proactively respond to emerging problems.

The ADMS project is a component of the Company's 2022-2025 GMP, and the Company currently expects to place its ADMS in service in 2024.

6.3.1.2 Communications

Wireless Communications Improvements and Communications System Modernization

The Company will continue to focus on the build out of a sub-1GHz private radio network, purpose built for its SCADA and other distributed automation requirements. A purpose-built field area network (FAN) addresses the needs of the SCADA network, aligns with Eversource's guiding principles and provides a pathway to achieve the future state. This proposed network will be designed to improve the communications network connectivity, improve bandwidth, and meet the increased frequency of data communications to remote units as required by the Company's real-time systems.

As a part of its 2022-2025 GMP, the Company will design a comprehensive network for data communications in eastern and western Massachusetts, which includes selection of base radio frequency, antenna locations and configuration of radios. This infrastructure will complement the Company's existing wireless communications network, including private radio and public carrier cellular.

The new network will improve the Company's ability to monitor communications network traffic, which in turn enable the optimization of the network and efficient identification and mitigation of communications issues that can adversely impact the real-time systems. It will also be capable of providing remote access to distribution devices, allowing for remote monitoring and adjustment of setpoints of these devices. In addition, improvements to the private communications network provides the opportunity to transition some of the public carrier cellular-connected devices to the newly improved network, if it is determined that this will improve the connectivity performance and reliability of the device.

The Company is planning the transition to internet protocol ("IP") on its FAN and eliminate data concentrators along the communications path to improve the resiliency and reliability of the data path from field devices to the Company's Energy Control System (ECS). Building out an IP-based communications network will establish a modern communications path for the transmission of data on the distribution system. The Company's serial to IP migration plan will replace serial-connected field devices with an IP based distributed network protocol (DNP) connection.

The migration from serial protocol to IP will enable remote access to field devices for engineering review and corrective actions (e.g., remotely changing distribution device set points). Remotely troubleshooting field equipment presents opportunities to reduce trouble resolution time, enable earlier identification of issues and enhance flexibility for the Company to remotely adjust setpoints on thousands of devices, reducing maintenance costs. This flexibility will better allow these devices to stay current with an ever-changing distribution system.

Wireless Communications Improvements and Communications System Modernization are a part of the Company's 2022-2025 GMP.

6.3.1.3 Substation Automation

One of the most important characteristics of the modern grid is the proliferation of advanced sensing technology to provide visibility and control to the grid edge. Widespread visibility into system conditions is the foundation upon which all advanced intelligence and real-time response depends. These investments will provide additional telemetry to support the DMS, providing a higher fidelity system model to distribution operators.

The program has two components. First, the Company will continue its program to replace older relay technology with current microprocessor relay technology for 190 additional feeders at bulk substations across Massachusetts. These relays will be equipped with incremental remote monitoring capability to enable more timely engineering analysis of system events. Second, the Company will continue its program to add relays with remote telemetry to 55 high priority 4 kV feeders in eastern Massachusetts.

The goal is to continue this program to increase the penetration of advanced remote telemetry devices in substations. These devices provide system operators with remote visibility and control of power flows on the grid required to optimize system conditions regardless of local penetrations of load and generation. The scope of work will prioritize locations that will provide telemetry to increase the accuracy of DMS power flow calculations.

6.3.1.4 Industrial Power Quality Monitoring

This initiative provides remote access and storage of continuous power quality data, so that detailed information from disturbance events can be evaluated by Eversource Distribution Engineering, System Planning and Protection and Controls Engineering to determine root causes and potential remediation needs. This information can be shared by Eversource, in a collaborative effort with affected commercial and industrial customers, to provide appropriate situational awareness and/or develop mitigation strategies for disturbances that occur outside of predefined thresholds as appropriate.

Industrial customers with sensitive loads will benefit from power quality metering that will support proactive identification and analysis of power quality events. This information will inform the potential need for future system improvements to reduce these types of events without reducing overall system reliability.

6.3.1.5 Volt-Var Optimization (VVO)

As a part of its GMP investment portfolio, the Company has established a VVO program to actively manage voltage and reactive power to increase system efficiency. As a part of its VVO program, the Company is deploying overhead distribution line equipment used to control voltage and reactive power (voltage regulators, capacitor banks, microcapacitors, and substation load tap changers) equipped with remote communication and control capabilities. Using centralized software logic to send commands to these line devices, the Company is able to direct power flows with the objective function of increasing system efficiency. To date, the Company has demonstrated a 1.8% reduction in demand and 2.2% reduction in energy consumption on feeders with VVO deployed, reducing carbon emissions typically generated through power delivery on the distribution system and lowering customer bills by lessening charges associated with energy lost in delivery.

As a part of its 2022-2025 GMP, the Company is planning to deploy VVO at 12 substations across Massachusetts.

6.3.1.6 Advanced Load Flow (ALF)

Interconnection Automation

In support of increasing the efficiency and effectiveness of the interconnection application study process, Eversource is procuring a software solution to enhance the Company's capabilities to assess interconnection impacts quickly and accurately to safely and reliably interconnect as much DER as possible to support the State's 2030 and 2050 clean energy policy objectives. In addition, efforts will be made with existing vendors for Power Clerk, PSCAD, and Synergi to integrate these tools into the proposed platform and increase functional capabilities. The Solution will be specifically tailored to the Massachusetts interconnection process.

By merging hosting capacity information into the interconnection platform and providing users the ability to interact with the hosting capacity data, users will be able to evaluate different options (location, curtailment, active management, storage, etc.) directly during the interconnection process. Specifically, the interaction with customers as they evaluate their interconnection before filing it will provide more clarity on the potentially associated cost and risk of the interconnection, and potentially reduce the time to process the interconnection request.

Analytics Platform

The Company will establish the cloud infrastructure to support the software solutions including storage, compute, web services, private endpoints, virtual networks, and data routes in development, test, and production environments. Appropriately sizing environments, will allow data scientists at Eversource to design and build data-first solutions in development, deploy the solutions in the test environment for verification and finally deploy intelligence-ready products in the production environment. Security components in this buildout will protect Eversource data and maintain secured communication between several system of records mentioned earlier and the data analytics solutions.

In addition, a cloud intelligence platform will provide a data orchestration solution hosted in the cloud infrastructure described above. The cloud intelligence platform will enable Eversource to analyze large volumes of data coming from disparate systems, study interrelationships, and develop statistical models for forecasting and early warning. The platform supports large scale automated machine learning. The Analytics Platform project will empower employees with latest machine learning tools and help build solutions at scale.

Probabilistic Power Flow Modeling

The Company will implement improvements to distribution modeling capabilities and support investments in enhancing necessary data analytics solutions. The Company has already invested in automating the process of retrieving models, preparing them for analysis, running load allocation, and performing hosting capacity analysis. The Company will build upon these investments and advance automation capabilities to include probabilistic load flow calculations which will provide the Company with an understanding of not just the magnitude and timing of the constraints on its system but their associated risk levels which would in turn inform a more efficient distribution system plan.

The Company will gain capabilities which will help address the challenges of a decentralized generation infrastructure. In addition, Eversource is expecting to improve modeling of the interplay of systems such as VVO with distributed resources. By developing a risk-based assessment for distribution planning, scenarios and projected grid conditions can be evaluated based on their probability to occur, informing investment decisions and prioritization. This will also advance the use case for alternative solutions to system constraints, as all scenarios causing the constraint can be identified and very targeted programs created to address these constraints.

6.3.1.7 Distributed Energy Resources Management System (DERMS) Phase I

The Company investment in a Phase I DERMS will result in the implementation of a platform system that is inclusive of the IT environment, operational control software and forecasting tools that will enable the monitoring and control of DER on the distribution system. The main system to be deployed will connect a database of DER assets with specific operating parameters to the model-based distribution management system. The Company will perform data gathering and cleaning to support DERMS control capability regarding specific DER operating setpoints (MW/MVAR output, PF settings, volt/watt curves, frequency/watt curves). This data gathering activity will be focused on one operational area within Eversource's service territory to prove out functionality before scaling up the effort for the remaining service territory beyond 2025. (See Section 6.3.2 for description of proposed DERMS program for 2025-2029.

Once the DERMS platform is established, an interface will be built to the Company's distribution management system so that a system operator can perform study cases and real time actions that will send commands to DERs that are participating. The commands include open and close, changing local operational modes, and specific set point control. In addition to real time monitoring and control, the Company will also build near term forecasting capability in system operations that will predict load and generation on the distribution system in the day ahead to week ahead time frame. Forecasting results will be used to inform the Company's existing operational planning activities on the distribution system.

6.3.1.8 Advanced Metering Infrastructure (AMI) and Data Sharing

The Company is implementing a comprehensive near real-time AMI system that includes state of the art meters, communications infrastructure, head-end system, meter data management system (MDMS), customer information system, analytics capabilities, customer portal and data sharing abilities, integrations with other key systems including the outage management system (OMS), and all with comprehensive, end-to-end, cybersecurity protocols.

Whereas early AMI deployments focused primarily on basic functions such as remote meter reading and interval usage data collection, utilities are increasingly taking advantage of systems integration, data analytics and grid-edge computation to provide incremental benefits without adding significantly to the overall project cost.

A modern AMI deployment reflects the imperative to consider AMI as more than meters and communications infrastructure but rather as a complete system, inclusive of systems and integrations that together will optimize the full utilization of this technology. A comprehensive approach to AMI deployment for Eversource customers will maximize benefits and minimize costs to customers.

The Company's AMI deployment between 2022 and 2028 will deliver on the potential of AMI to provide value-added outcomes for customers. Many of the benefits enabled by AMI accrue directly to customers. Access to usage information, insights, alerts, and availability of optional time-varying rates, for instance, will provide customers with new opportunities to manage energy consumption and lower bills. Many of the benefits unlocked by AMI will accrue indirectly to customers. Expenses such as theft and other losses are socialized to all customers can be reduced through initiatives made possible with an AMI deployment. Some benefits, such as reduced truck rolls, are focused on improving the Company's operational efficiency when providing service to customers. For customers, AMI will enable increased access to more granular usage information, improving the customer's understanding of energy savings opportunities. This information has the potential to be powerful for the customer when combined with new rate designs and participation in energy efficiency and demand-response programs. AMI may also improve the efficacy of optional customer information tools such as load disaggregation applications. Customers will benefit from more timely updates from the Company, such as mid-cycle high bill alerts and customer-directed bill alerts, which are service offerings that are proven to be of value to customers. In addition, call center representatives would have access to more granular data putting them in a better position to help customers understand how changes in their usage impact changes in bill amounts and recommend participation in energy efficiency programs. Another customer benefit of AMI technology is improved frequency and precision of communications during outages and storm restoration, as well as reduced time for meter transactions, including service turn-on's, which can be conducted quickly and efficiently.

AMI and Data Sharing

AMI implementation will advance the ongoing energy affordability dialogue in the State, particularly in underserved communities. Full deployment of AMI to all Massachusetts customers will provide several opportunities to leverage access to information to that will help customers to better manage their energy usage. Unlocking customers' ability to lower bills with AMI data will have multiple components:

- Detailed Usage Insights. Access to detailed billing data is expected to provide value to multiple different customer segments. Residential customers will benefit from targeted information on how different rates or programs will impact bills based on their specific usage patterns. All customer segments have the potential to benefit from visibility of near real time usage data. In the same way people can glance at a gas gauge on their vehicle or the battery life of their smartphone, visibility to this data will enable customers to rapidly modify behavior and better manage their usage. Access to more timely and detailed usage information is expected to support improved insight and reduce customer surprises with high bills. With access to this information, customer service representatives will also be able to provide more targeted recommendations to callers for participation in time-varying rates or energy efficiency or demand response programs.
- Detailed Usage Sharing with Third Parties. Via the Eversource website, customers will be able to access their data as well as applications that allow them to share their usage data easily and securely with third parties. AMI data will be made available via those existing methods and additional data sharing mechanisms that may be made available in future years. For example, customers may authorize their Competitive Electric Power Supplier ("CEPS") or other service provider to access their monthly, daily, and interval data. Approved CEPSs can download current customer usage, demand data, and interval data along with 12 months of historical information.
- Customized High Bill Alerts. Eversource will also allow customers the option to receive relevant energy insights and notifications based on detailed data out to customers via outbound channels, namely email, text, and mobile application notifications. Customers will be able to set thresholds to receive alerts when the amount of their bill for a defined period exceeds a certain amount.
- Time-Varying Rates. Once all AMI meters have been deployed and the Customer Information System has developed the Time-Varying-Rates design determined, Eversource will be building awareness and educating customers on Time-Varying Rates. Eversource will accomplish this by using existing communications tools, such as customer emails, on-bill messaging and inserts, free social media, online videos, press releases and earned media, direct mail, print collateral, town halls, and paid social media campaigns.

In addition to the use of AMI data sharing to enable customers to lower bills and take advantage of opportunities to deploy clean energy solutions, the Company will use the more granular and accurate data generated by AMI to improve outage communications in storm events. In particular, with complete situational awareness of customer outages in storm events enabled by AMI data, the Company will provide more timely and targeted restoration time estimates.

6.3.2. Description of Implementation Justification and Expected Benefits – Proposed Programs for 2025-2029

6.3.2.1 Grid Modernization Technology – Enabling DER to Provide Grid Services

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

- **Grid Service Study (Joint EDC Proposal).** Engage a third-party consultant to support a study of the value of DER and load flexibility as a locational grid service. Building on a work supported by the Mass CEC, the study would establish specific levels of compensation for locational grid services, considering the value they create in either capacity or voltage support use cases, depending on their level of availability and assuming direct utility visibility and control to ensure safe and reliable grid operations. The study would include provisions for the added value dispatchable DER can provide in underserved EJ communities. The study would also recommend process mechanisms to implement compensation framework based on minimizing implementation cost and increasing value to DER facilities. The EDCs are proposing to conduct the study collaboratively with input from stakeholders.
- **Grid Service Compensation Fund.** Establish a fund to compensate dispatchable DER and flexible loads participating in a program to allow utility dispatch to provide grid services. Dispatchable DER and flexible load with capacity to provide grid services would be eligible for compensation consistent with the recommendations from the Grid Service Study. Operating guidelines would ensure facilities were dispatched by the Company based on mutually agreed upon parameters that ensure no violation of interconnection agreements and provide clarity to customers on the impact to operational flexibility.
- **Equitable Transactional Energy Study (Joint EDC Proposal).** Building upon learnings from the Grid Service Demonstration, the Company proposes a second study to develop recommendations for a more dynamic locational value compensation framework. The study would take into consideration the implication of dispatch large numbers of smaller facilities in a virtual power plant (VPP) configuration that have the flexibility to choose their level of participation at any point in time. The study would include a framework for dynamic pricing mechanisms to reflect a higher value of DER in underserved EJ communities. The result of the Equitable Transactional Energy Study would inform proposals in the Company's 2030-2034 ESMP.

Payments made to participating FTM DER facilities would be based on the value framework established in the FTM Grid Services Study and the Company would cap total customer payments at $15 million over the five-year ESMP term. Knowledge gained through this effort will inform future efforts to determine the optimal level of incentive to encourage DER participation as grid assets, while minimizing costs to customers. The ability of the Company to implement this program assumes authorization to deploy the DERMS Phase II investment described below.

Customer Value. The need to address the load growth associated with beneficial electrification and further support for DER integration is posing new challenges to ensure the just transition to a cleaner energy future. As described in this report, the need to build out the capacity of the system to accommodate load growth and enable decarbonization is undeniable. This infrastructure deployment will provide the grid flexibility required to ensure all customers have access to the benefits of clean energy. Investments in utility infrastructure alone, however, fail to achieve the full promise of grid modernization. Utilizing current and future clean energy DER as a grid asset is a critical component to the total solution, making use of all available resources to optimize the distribution grid for cost-effective clean energy deployment. Together, capacity upgrades supported by DER used to provide grid services ensure all tools in the tools box are utilized to meet the Commonwealth's aggressive clean energy objectives.

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

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

Determining the proper level of compensation for DER providing grid services is a relatively complex undertaking, involving multiple considerations. The value of DER is critically dependent on its availability. System operators today count on utility owned and maintained infrastructure constantly monitored to ensure availability. A resource that is not owned or maintained by the utility has lower levels of availability. Fully optimizing the safe, reliable, and low-carbon delivery of electricity requires visibility and control of DER by real-time utility system operators as well as operating agreements to ensure consequences in the event a resource is not available when called upon based on contract provisions. Availability concerns diminish with the number of resources under dispatch. In a VPP configuration, if 100 resources are theoretically available to address a local system need, if the utility assumes a certain percentage will be available at the time of the event, the risk is lessened. This concept of statistical availability is most applicable for large numbers of smaller BTM assets.

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

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

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

6.3.2.2 Grid Modernization Technology – Distributed Energy Resource Management System (DERMS) – Phase II

Investment Summary: Defined as control room tools 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. This investment will expand DERMS Phase I capabilities initially deployed as a part of the Company's 2022-2025 Grid Modernization Plan (GMP) to provide increased functionality across the Company's service territory as required to capture more fully the value of DER. This investment includes four components.

- **Grid DERMS Expansion.** In its 2022-2025 GMP, the Company was authorized to implement DERMS technology. Although this GMP DERMS project is still under development in advance of an estimated 2025 in-service date, the current project plan is to deploy a Grid DERMS in one of the Company's four control rooms serving customers in western MA. The Grid DERMS deployed in western MA will interface with the Company's distribution management system (DMS) such that DERMS will receive information on real time power flows to forecast the specific time, location, and extent of system constraints to allow the DERMS to identify the specific DER available to address system need. The GMP DERMS project is also expected to support an interface to the Company's Aggregator DERMS that currently dispatches BTM DER to address ISO peak, without interface to the Company's real time systems. The investment proposed for 2025-2029 will expand the Company's GMP DERMS to achieve full deployment in all four of the Company's distribution control rooms to provide Grid DERMS and forecasting capability for entire service territory.

- **SCADA Energy Control System Upgrade.** As described in Section 4, the SCADA ECS is the secure system that provides measurement information from substation and distribution line equipment and enables remote control of distribution equipment. The SCADA ECS is the foundation for the DMS and Grid DERMS. The DMS provides system operators with a real-time, as-operated load flow of the distribution system. This real time load flow is based on distribution asset information and real time telemetry from the Company's SCADA ECS to create the load flow. The DMS load flow provides the inputs required to support DERMS dispatch decisions. The Company currently uses a newer version of its SCADA ECS software in its western MA service territory. This investment proposes upgrading the eastern MA SCADA ECS software to the same version for a common platform across Massachusetts.
- **Implement New DERMS Functionality.** DERMS technology is rapidly evolving to keep pace with the evolving landscape for DER dispatch use cases and enabling policies. The Company's current project to deploy a GMP Grid DERMS has focused on preliminary use cases that leverage basic DERMS functionality. These use cases include facilitating DER interconnection with DERMS-managed operating guidelines and dispatch of FTM DER to address local capacity constraints. Future use cases the Company proposes to implement require additional DERMS functionality. These future use cases include items such as, combined dispatch of FTM and BTM DER based on DMS identification of capacity or voltage constraints (including compensation framework discussed in Section 6.3.2.1; microgrid coordination; and market-based dispatch to prioritize DER dispatch based on a newly created DER cost framework. As a part of this investment, the Company will implement any required software or tool upgrades.
- **Control Room DER Dispatch Process Improvements:** In addition to technology improvements, fully capturing the promise of DERMS, the Company will need to establish new processes to administer DER dispatch for multiple uses cases. Currently, system operators are responsible for ensuring safe and reliable power flows on the distribution system. Adding additional requirements to oversee the dispatch of DER will require new processes and labor resources. These new functions will include support and maintenance of the new DERMS system, engineering support for dispatch decision optimization, and administrative support for maintaining operating guidelines and customer agreements.

Customer Value: Customers will benefit from DERMS Phase II investments that enable the Company's system operators to more effectively dispatch customer-owned DER to alleviate system constraints, reducing costs by making more efficient use of existing and new clean energy assets to provide grid services. Although targeted investments in building out system capacity to accommodate electrification and DER interconnection are inevitable, these investments must go together with the use of DER as grid assets. Neither solution by itself is sufficient to cost-effectively meet the Commonwealth's decarbonization objectives. Investments in DERMS Phase II will provide tools necessary to fully utilize the value of DER as a grid asset.

The increasing complexity of the distribution system characterized by greater prevalence of two-way power flow and automated self-healing capabilities, is driving the need to increase investment related to the technology, people, and processes responsible for maintaining real-time operation of power flows. Currently, system operators who staff the Company's 24/7 system control centers (SOC) are dedicated to maintaining safe and reliable flow of electricity on the distribution grid. They are responsible for closely monitoring system conditions and reacting to emergent conditions, they direct all remote and manual switching operations to make the system safe for planned and emergency work by line crews and oversee redirection of power flows for automated self-healing operations. System operators also monitor customer outage calls and dispatch crews to trouble locations.

Given its direct, real-time knowledge of system conditions and responsibility for safety and reliability, the Company's SOC must be the entity responsible for real-time monitoring and control of DER on the distribution system. The investment in DERMS Phase II will build upon existing SOC capabilities and more fully integrate DER dispatch into the Company's real time system operations, providing the tools and resources to first ensure DER has no adverse impact on the system, and second identify and implement DER dispatch to optimize power flows.

The DERMS Phase II investment will support cost-effective use of clean energy resources in multiple ways. First, it will build upon existing capabilities to minimize implementation costs. Existing investments in DERMS Phase I and SCADA ECS will be leveraged to focus on deploying new functionality that takes advantage of existing capabilities. Second, DERMS Phase II will add capabilities to more cost effectively implement VPP capabilities. To dispatch multiple DER facilities to respond to a specific grid need, advanced tools will ensure the most cost-effective resources are selected for dispatch without violating operating constraints. Third, operating efficiencies will be gained by adding identical functionality to systems in eastern and western MA. Features such as automatically generated schematics will reduce manual labor. Fourth, new opportunities for unlocking value will be created with DERMS functionality such as microgrid control to leverage DER in resiliency use cases.

6.3.2.3 Grid Modernization Technology – Federal Energy Regulatory Commission (FERC) Order 2222 Implementation Capabilities

Investment Summary: With the issuance of FERC Order 2222, distribution system operators are anticipating an additional challenge of ensuring safe and reliable grid operations while managing the impact of coordinated dispatch of aggregated DER participating in wholesale markets. Although the specific guidelines and processes for implementation of FERC Order 2222 in the ISO-New England market are still under development, the Company recognizes as the distribution grid operator it must be prepared play an active role in successful implementation. Although specific requirements for FERC Order 2222 implementation remain under consideration, the Company anticipates it will need to address the following operational needs in advance of full implementation.

- The Company must have sufficient information regarding dispatch schedules to conduct operational load forecasts used to inform switching operations, maintenance, or respond to anticipated critical events such heat waves.
- Dispatch decisions must be informed by an awareness of anticipated system constraints, planned outages, and other events that might limit access to resources before final plans are established. Absent this awareness there may be a need for curtailment of DERs by the EDCs based on real time system conditions.
- During critical system events such as N-1 conditions (e.g., outages, faults, storm events), real time communication between aggregators and utilities is essential as system conditions change rapidly, requiring an adjustment of dispatch.

To address these needs, this investment will result in the implementation of tools and processes to communicate with ISO-NE to receive notice of a proposed future (e.g., day-ahead) dispatch of aggregated DER, quickly study the impact to the distribution grid, respond to ISO-NE to identify requirements to limit dispatch to avoid distribution system impact (if any), and monitor ISO-NE dispatch in real time to identify impact due to unforeseen emergent conditions, such as an outage event.

Customer Benefit. The promise of FERC 2222 implementation to facilitate DER dispatch to support wholesale market needs (e.g., system peak load reduction) is similar to the distribution use case, increasing the value of existing and new DER by making its use to provide grid services possible. This investment will ensure that the Company is ready to support implementation of FERC 2222 in support of this use case. Further, combining investment in FERC 2222 readiness with investments described above supporting use of DER as distribution grid assets, the Company will be positioned to ensure seamless implementation of DER dispatch for all use case, further supporting the objective of cost-effective optimization of clean energy DER.

6.3.2.4 Grid Modernization Technology – Southampton Battery Energy Storage System (BESS) for Volt-VAR Optimization (VV0)

Investment Summary. Eversource is proposing to install a BESS at an existing Eversource photovoltaic (PV) site, located in Southampton. The project includes the installation of a 2MW/3MWh BESS at the site to provide smoothing of the PV output as well as an oversized 3MVA inverter to provide reactive support in addition to the active power output of the battery. The BESS will provide voltage/reactive power support for the circuit 15 A1 out of the 15A Gunn substation. The BESS will provide additional capabilities for the site to be leveraged through the Company's VVO and DERMS platforms.

Co-locating a BESS solution with DERs will enable coordinated charging/discharging such that the net export at the common point of interconnection (POI) is smooth and dependable. The advanced control capabilities of the inverters at both assets will also allow for integration into the VVO and DERMS system which will create dispatchable resources to improve voltage and power quality for the surrounding distribution system. This project will expand Eversource's understanding of such co-located installations and their benefits to inform further investments in other areas of the Company.

In addition, the project will create communication links between the PV and BESS plant controllers to share measured output and charge levels as well as assigned set points and schedules. Telemetry and control to both sites will be aggregated and brought to the Springfield System Operations Center (SOC) and commissioned into the Energy/Distribution Management System (EMS/DMS) for dispatch by system operators or automated control algorithms.

Customer Benefit. Since 2018, as a part of its Grid Modernization Plan, the Company has been investing in VVO to reduce energy consumption and peak demand by increasing system efficiency with the remote control of voltage and reactive power management devices on the overhead system based on logic controlled by centralized software. These investments have proven to be beneficial and cost effective, resulting in 1.8% reduction in demand and 2.2% reduction in energy consumption on feeders with VVO deployed, reducing costs to customers. Adding the use of advanced inverters an additional tool to manage voltage and reactive power has the potential to supplement these gains for further energy conservation benefit. This investment will demonstrate the benefit of using an advanced inverter as a part of an existing VVO scheme deployed at the Gunn substation in western MA. The Company will study the use of the Southampton BESS in a VVO scheme to gain a better understanding of the costs and benefits of this technology. These insights will inform potential future compensation for customer-owned DER facilities to participate in the Company's VVO operations. In coordination with efforts detailed in Section 7.1.1.1. above, the Company will have information to inform future compensation mechanisms for the use of customer-owned DER as grid assets.

6.3.2.4 Grid Modernization Technology – Advanced Forecasting and Modeling

Investment Summary. As described in Sections 4.7.7 and 5.1.1.10, the Company has initiated investments in sophisticated tools and processes to develop forecasts of load and generation over the 10-year planning horizon. System planning models and forecasts are the basis for all distribution system needs assessments used to develop investment plans. Further support is needed to continue to advance the Company's forecasting and modeling capabilities. The growing complexity of the distribution system, characterized by two-way power flow and self-healing automation, will continue to drive the need for scenario planning that identifies system needs under multiple possible future configurations of load and generation growth. This investment will ensure the Company continues to implement industry-leading tools and processes for forecasting and modeling with additional technology for data analytics and labor to implement these tools over the five-year investment horizon.

1 **Customer Benefit.** As described in Section 7, the Company plans to invest over $1.2 billion in capacity upgrades between 2025 and 2029. Maximizing benefit for associated cost will be critical to reducing bill impacts in the just transition to a cleaner energy future for Massachusetts customers. Investments in advanced forecasting and modeling will ensure that the information informing decisions on capacity improvement needs and prioritization is detailed and comprehensive, despite growing complexities and uncertainties. The investment will also support further transparency in forecasting assumptions, ensuring robust stakeholder participation in capacity investment decisions.

6.4. Planning Sub-Regions

As discussed in more detail in Section 4, the Planning sub-regions that comprise the Eversource Massachusetts service area include:

- EMA-North (former Boston Edison and Cambridge Electric Light Company service area),
- EMA-South (former Commonwealth Electric service area), and
- WMA (former Western Massachusetts Electric Company service area).

The EMA-North subregion is further broken down for planning purposes as follows:

- Metro Boston sub-region (including the cities of Boston, Cambridge, Somerville, Chelsea, and the Towns of Brookline and Milton), and
- Metro West sub-region including 35 communities in the Metro West and North Shore areas.

The discussions of capacity/reliability deficiencies and needs and project solutions to address those deficiencies are discussed separately for each of the four regions in Section 6.5 to Section 6.8 below.

As clean energy hubs, bulk substation upgrades and additions by 2035 increase the electrification headroom by 3.4 GWs. Specifically, the five-year planned new and upgraded substations (1.8 GW) enable 1.7 million electric vehicles or the equivalent of 360,000 residential heat pumps. Correspondingly, the ten-year planned suite of new and upgraded substations enable a total of 3.3 million electric vehicles or the equivalent of 680,000 residential heat pumps. To the extent the electrification programs are coordinated with the grid capacity upgrades, this ESMP plan enables 100% of the Commonwealth's 2035 clean energy goals.

6.5. EMA – North Metro Boston Sub-Region

The Eversource EMA-North Metro Boston Sub-Region consists of portions of four Cities, (Boston, Cambridge, Somerville, and Chelsea), and two Towns (Brookline and Milton) in Eastern Massachusetts served out of the Company's Massachusetts Avenue (Dorchester) and Somerville AWC's. The service area encompasses a population of approximately 852,000 residents and many high- to medium-load density areas, including some of the highest density load areas in the country in downtown Boston and Cambridge served by large underground secondary and spot networks.

The detailed overview of forecasted demand for in Section 5 shows that over the next decade, the electric demand for the summer peak in the EMA-North Metro Boston Sub-Region is expected to go from ~2.4 MVA in 2023 to ~2.9 MVA in 2033, an increase of over 20% over the planning horizon driven almost exclusively by large step load additions in the region. However, the growth in the last five years is likely to be even greater because the forecast does not include information on step loads beyond five years, but based on current trends, they will likely be a significant factor in that timeframe.

To meet its obligation to provide reliable service to all customers, the Company has assessed the impact of 90/10 weather-normalized forecasted demand on each of its bulk distribution substations. This assessment is conducted on a yearly basis to evaluate impact of underlying load growth, as well as several adders that impact the peak demand and substation capacity constraints, including electrification trends (see Section 4.1.6 for a more detailed description of the planning process). The following subsection details the system needs and major projects planned, proposed, or envisioned to safely and reliably meet those needs on a localized basis.

6.5.1. Major substation projects

6.5.1.1 Capacity and Reliability Needs

Through its annual capacity planning processes,[146] as summarized in Section 4.1.6 and reported in the ARR under DPU docket 23-ARR-02[147] and as reported in the Company's Rate Case Filing under DPU 22-22,[148] the Company identified municipalities and neighborhoods that are currently supplied by electric power system (EPS) infrastructure with future projected capacity[149] and/or reliability[150] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP), communities supplied by bulk distribution substations expected to be at capacity within the next ten-years. Due to the size of the region, in terms of demand, the capacity and reliability needs are separated into 1) Metro Boston Needs, and 2) City of Boston Needs.

Metro Boston Needs (not Including the City of Boston)

Table 43 below is a community-centric view of capacity deficiencies. The table lists the communities in EMA-North Metro Boston (not including the City of Boston), with existing or projected substation supply deficiencies by type (Reliability and/or Capacity), and the timeframe for the need - substation at capacity now (2023 to 2024), at capacity within 5 years

---

[146] Refer to Section 4.1.6 for details on the capacity planning process

[147] "2023 Annual Reliability Report." NSTAR Electric Company d/b/a Eversource, March 31, 2023. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17334261

[148] The list of projects provided is from Responses to IR's RR-AG-26 and DPU 21-4 to the Eversource Rate Case Petition D.P.U 22-22

[149] Capacity deficiency violation is defined as the projected substation peak load exceeding the substation peak or Firm Capacity

[150] Reliability deficiency is defined as a violation of system planning/design criteria that results in degraded system performance under emergency conditions. This reduced system performance has the potential to result in longer duration and/or more frequent customer outages. This could include long-duration outages of weeks or even months.

(2025-2029), at capacity within 10 years (2030-2034), or at capacity beyond 10-year planning horizon (2035+). For consistency with the information provided earlier in Section 4 Section 4.3.7, the table also lists the communities that have both existing and on-going supply deficiencies.

Table 43: Metro Boston Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency/Need	Timeframe for Need
Brookline	Town	Norfolk	Capacity	Within 10 years
Cambridge[151]	City	Middlesex	Capacity and Reliability	Now/Existing
Chelsea	City	Suffolk	Capacity and Reliability	Now/Existing
Milton	Town	Norfolk	Capacity	Now/Existing
Somerville	City	Middlesex	Capacity and Reliability	Now/Existing

Table 44 below is a substation-centric view of capacity deficiencies in Metro Boston (not including the City of Boston). The table shows the substation name or location in the first column, followed by the Community that is supplied by the substation. Some communities are supplied by multiple substations, so they will repeat for each substation. For example, the town of Brookline is supplied by both the Brighton and LMA substations.

The table also shows how constrained the substation is projected to be by 2030 compared to its thermal capacity rating. This number is shown as a percentage and is a computed as the substation projected peak load divided the substation capacity. A value greater than 100% is a violation of Company distribution planning criteria since the transformers' expected peak load will exceed the substation capacity. The last column on the table shows the associated 2025-2029 or 2030-2034 project solutions, later described in Sections 6.5.1.2 and 6.5.1.3, to address the projected overload.

[151] Refer to EFSB 22-03 and DPU 22-21, Greater Cambridge Energy Program, Cambridge, Somerville, Boston for all Cambridge Substations forecast and capacity deficiencies.

Table 44: Metro Boston Substations with Projected Deficiencies and Communities Impacted

Substation Name or Location	Communities Supplied	2030 % of Substation Capacity	Project Solution
Brighton	Brookline, City of Boston	96	Bulk Distribution Transformer Additions
Longwood Medical Area (LMA)	Brookline, City of Boston	98	Allston/Fenway/Brookline Substation
Hyde Park	Milton, City of Boston	104	Future Hyde Park – Dorchester Area Supply Initiatives
Everett[152]	City of Somerville, Charlestown	99	Somerville 115/14kV Substation #402 Expansion and Charlestown/East Boston Substation
Chelsea[153]	East Boston, City of Chelsea	110	New East Eagle Street 115/14kV Substation # 131
East Cambridge	City of Cambridge – East	109	New Cambridge 115/14kV Substation #8025
Putnam	City of Cambridge – South	96	New Cambridge 115/14kV Substation #8025
Somerville[154]	City of Cambridge – North	85	Somerville 115/14kV Substation #402 Expansion
Alewife[155]	City of Cambridge – West	85	Bulk Distribution Transformer Additions

Through its annual capacity planning processes, as noted in the ARR, the Company's goal is to develop a *planning* solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon and to initiate a project to resolve the capacity deficiency prior to the need date.[156] However, despite the Company's best laid plans to develop and implement solutions for forecasted needs, there are times when the project implementation might miss the need date, due to a number of factors, primarily siting and permitting delays. When this occurs, the Company has an obligation to develop interim or emergency *operational* measures to ensure that customers are not unserved during an outage. These measures could include

[152] Substation physically located in Everett supplying Charlestown and the City of Somerville
[153] Refer to EFSB 22-01 Final Decision dated November 30th, 2022, at Table 2
[154] Percent of Substation capacity in 2030 assumes the third transformer is in-service. Percent of Substation capacity in 2023 is limited by Distribution System Emergency Limit (66MVA) and assumes upgrades at Somerville Substation #402 have not been placed in-service in 2023. The company had a plan to install a third transformer at the Substations by 2023, now schedule for year 2024. With the 3rd Transformer the forecasted 2023 Percent of Substation capacity is approximately 58%. Refer to EFSB 22-03 and DPU 22-21 at 2-24 and at Table 2-14.
[155] Percent of Substation capacity does not account for recent 2023 large new business growth in the area, which will decrease the available operational capacity starting in 2024 and beyond.
[156] First date when the deficiency or criteria violation is manifest based on forecasted demand

anything from permanent load transfers to other substations, to temporary spot generation deployment, to development of non-wires alternatives such as battery storage where feasible. However, these options are only temporary measures and will be exhausted and ineffective as load continues to grow. A permanent planning solution must be implemented at some point to ensure long-term reliable service.

A good example of this scenario in Metro Boston is the planned project to address capacity and reliability needs in East Cambridge and the greater Cambridge area. Back in 2014, 9 years ago, the East Cambridge substation was projected to be loaded beyond its thermal capacity by summer of 2020, the need date. The project solution, a new substation in East Cambridge, was initiated, planned, and designed to be constructed and commissioned by the need date. However, due to delays in siting and permitting, the project has not yet been approved for construction. In the meantime, to reduce the risk of outages to customers in East Cambridge, the Company has implemented and proposed several interim emergency operational measures which are described in detail in Section 4.3.7. And this further highlights necessary siting reform to ensure critical grid upgrades necessary to enable electrification and maintain safe and reliable service can be constructed within the required in-service date.

The data in Table 43 above shows that during the ten-year planning horizon, four additional substations (incremental to the ones identified in Section 4) are projected to have capacity and/or reliability violations. These are Brighton, LMA, Everett, and Putnam.

City of Boston Needs

Similarly, Table 45 below presents a neighborhood-centric view of capacity deficiencies in the City of Boston. The table lists the neighborhoods in the city and the existing or projected substation supply deficiency by type and timeframe. For consistency with the information provided earlier in Section 4.3.7, the table also lists the communities that have both existing and on-going supply deficiencies.

Table 45: City of Boston Neighborhoods and Projected EPS Deficiencies

Neighborhood	Deficiency Type	Timeframe for Need
East Boston	Capacity	Now/Existing
Dorchester	Capacity	Now/Existing
Jamaica Plain	Capacity	Now/Existing
Mattapan	Capacity	Now/Existing
Roslindale	Capacity	Now/Existing
Hyde Park	Capacity	Now/Existing
South End	Capacity	Next 5-Years
Roxbury	Capacity	Next 5-Years
West Roxbury	Capacity	Next 5-Years
Charlestown	Capacity	Within 10-Years
West End	Capacity	Within 10-Years
Downtown	Capacity	Within 10-Years
Back Bay	Capacity	Within 10-Years
Chinatown	Capacity	Within 10-Years
Leather District	Capacity	Within 10-Years
Beacon Hill	Capacity	Within 10-Years
Fenway	Capacity	Within 10-Years
LMA	Capacity	Within 10-Years
Mission Hill	Capacity	Within 10-Years
North End	Capacity	Beyond 10-Year
Bay Village	Capacity	Beyond 10-Year
South Boston Waterfront	Capacity	Beyond 10-Year
Allston	Capacity	Beyond 10-Year
Brighton	Capacity	Beyond 10-Year

Correspondingly, Table 46 is a substation-centric view of capacity deficiencies. The table shows the substation name or location in the first column, followed by the neighborhoods in the City of Boston that are supplied by the substation. Some neighborhoods, such as Jamaica Plain, are supplied by multiple substations, so they will repeat for each substation. The table also shows how constrained the substation is projected to be compared to its thermal capacity rating. The last column on the table shows the associated 2025-2029 or 2030-2034 project solutions, later described in Sections 6.5.1.2 and 6.5.1.3, to address the projected overload.

Table 46: City of Boston Substations with Capacity Deficiencies and Impacted Communities

Substation Name or Location	**Community Supplied**	**2030 % of Substation Capacity**	**Project Solution (Refer to Sections 6.5.1.2 and 6.5.1.3)**
Chelsea	East Boston	**110**	New East Eagle Street 115/14kV Substation # 131
Andrew Sq	South End, Roxbury, Dorchester	**106**	Bulk Distribution Transformer

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.5.1.2 and 6.5.1.3)
			Additions
Hyde Park	Jamaica Plain, Mattapan, Roslindale, Hyde Park	**104**	Future Hyde Park – Dorchester Area Supply Initiatives
Dorchester	Dorchester, Mattapan	**100**	Future Hyde Park – Dorchester Area Supply Initiatives
Everett	Charlestown	**99**	Charlestown/East Boston Substation
(LMA)	Fenway, LMA, Mission Hill, Jamaica Plain	**98**	Allston/Fenway/Brookline Substation
West Roxbury	West Roxbury	**97**	Future Hyde Park – Dorchester Area Supply Initiatives
Bay Village	Downtown, Back Bay	**97**	Metro Boston Substation Supply Initiative
Brighton	Allston, Brighton	**96**	Bulk Distribution Transformer Additions
Chinatown	Bay Village	89	Metro Boston Substation Supply Initiative
West End	North End, West End, Beacon Hill	88	Metro Boston Substation Supply Initiative
Downtown	Downtown, Bay Village, Chinatown, Leather District	86	Metro Boston Substation Supply Initiative

Currently 2 of 17 substations supplying the City of Boston have a capacity and/or reliability deficiency, and during the ten-year planning horizon 12 of 17 substations are projected to have capacity and/or reliability deficiencies. This includes three substations supplying the Downtown Boston area (West End, Downtown, and Chinatown) that are expected to be loaded near 90 percent of capacity. All the substations supplying the Downton Boston area are of special concern because these are in the most heavily congested streets in the entire state. Due to the amount of subsurface infrastructure in the streets, a substation capacity solution could take more time to implement than in any other area of Metro Boston or the state for that matter.

As noted in Section 4.1.5, the Company's criteria and guidelines for the planning and design of its bulk distribution substations is for substation transformers to never exceed the substation thermal capacity, also known as the long-term emergency (LTE) rating. A value greater than 100% is a violation of the Company distribution planning criteria since the transformers' expected peak load will exceed the substation capacity. Through its annual capacity planning processes, as noted in the ARR, the Company's goal is to develop a *planning* solution for any substation expected to exceed 90% of its capacity during the 10-year planning horizon and to initiate a project to resolve the capacity deficiency prior to the need date.[157] However, despite the Company's best laid plans to develop and implement solutions for forecasted needs, there are times when the project implementation might miss the need date, due to a number of factors, primarily siting and permitting delays. When this occurs, the Company has an obligation to develop interim or emergency *operational* measures to ensure that customers are not unserved during an outage. These measures could include anything from permanent load transfers to other substations, to temporary spot generation deployment, to development of non-wires alternatives such as battery storage where feasible. However, these options are only temporary measures and will be exhausted and ineffective as load continues to grow. A permanent planning solution must be implemented at some point to ensure long-term reliable service.

A good example of this scenario in the City of Boston is the planned project to address capacity and reliability needs in East Boston[158]. Back in 2016, seven years ago, the Chelsea substation, which supplies East Boston, was initially projected to be loaded beyond its thermal capacity by summer of 2019, the need date. The project solution, a new substation in East Boston, was initiated, planned and designed to be constructed and commissioned by the need date. However, due to delays in siting and permitting the project approved approval for construction in December 2022 and is anticipated to be online by summer of 2025. In the meantime, to reduce the risk of outages to customers in East Boston, the Company has implemented and proposed a number of emergency operational measures, which are described in detail in Section 4.3.7.

6.5.1.2 Project Solutions 2025 - 2029

Through its annual capacity planning processes, as summarized above, and reported in the ARR under DPU docket 23-ARR-02[159] and as reported in the Company's Rate Case Filing under DPU 22-22,[160] the following projects have been either proposed or approved in the Company's Long Range Plan (LRP) and will be in-service by 2029 for mitigation of identified capacity and/or reliability deficiencies on the EMA-North Metro Boston electric power system (EPS) as discussed above.

[157] First date when the deficiency or criteria violation is manifest based on forecasted demand
[158] Mystic - East Eagle - Chelsea Reliability Project." Eversource, www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/mystic---east-eagle---chelsea-reliability-project.
[159] EEA File Service, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17334261.
[160] The list of projects provided is from Responses to IR's RR-AG-26 and DPU 21-4 to the Eversource Rate Case Petition D.P.U 22-22

All project solutions in this section are expected to be in service by 2029. Any project solution that will be in service after 2029, even if capital expenditure occurs before 2029, are included in the next section (Project Solutions 2030 - 2034). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

- **City of Boston: New East Eagle Street 115/14kV Substation # 131** – The station serving East Boston, Chelsea, is already at capacity. The need for a capacity and reliability solution in East Boston and interim operational measures currently being applied were discussed in detail in Section 4.3.7. A new substation has been approved to be constructed in the East Eagle neighborhood of East Boston with two 37/50/62.5 MVA transformers and provisions to accommodate a future 3rd transformer. As part of the Mystic - East Eagle - Chelsea Reliability Project,[161] the Company has already installed two new underground transmission lines to connect the new substation to existing substations in Everett and Chelsea. The Company is also making minor improvements within the fenced area of the existing Mystic Substation on Broadway in Everett, and the existing Chelsea Substation on Willoughby Street. Figure 150 below shows the location of the new substation. The long-term project solution will resolve existing reliability and capacity issues in the area and support increased loads as well as electrification and clean energy goals in East Boston and the City of Chelsea. The project solution (with the future 3rd bank) increases the area firm capacity supply by ~75 MW which will enable 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region. The Company received a Tentative Decision at the end of 2022 in the certificate proceeding for East Eagle Substation.[162]

[161]"Mystic - East Eagle - Chelsea Reliability Project." Eversource, www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/mystic---east-eagle---chelsea-reliability-project

[162] Refer to EFSB Approval for a Certificate of Environmental Impact and Public Interest (EFSB 22-01); Nov 30th, 2022

Figure 150: Location of the Planned New Substation in East Boston

- **City of Cambridge: New Cambridge 115/14kV Substation #8025** – The station serving East Cambridge is already at capacity. The need for a capacity and reliability solution in East Cambridge and interim operational measures currently being applied were discussed in detail in Section 4.3.7. As noted previously, the East Cambridge substation load relief project started in 2014 and was scheduled to be in-service by summer 2020. Due to delays in implementing the long-term solution, the company has been implementing interim operational measures that have address the East Cambridge Substation overloads. This includes the addition of a 4th Transformer at Putnam substation and distribution load transfer from East Cambridge Substation to Putnam Substation starting in 2020 until 2024. This has resulted in Putnam substation projected to be overloaded in the next 10-years. The long-term solution for the identified reliability and capacity deficiencies, for both Putnam and East Cambridge Substations, is the Greater Cambridge Energy Project.[163] As part of the project, the Company is planning to construct a new underground substation in Kendall Square, Cambridge (see Figure 151 below), along with five underground duct banks housing eight new 115-kilovolt (kV) underground transmission lines interconnecting to existing substations in the surrounding area. The new substation, #8025, is planned with three 90 MVA transformers, expandable to four. It will be located between Broadway and Binney Street and will be integrated into Boston Properties' redevelopment plans for the Kendall

---

[163] "Greater Cambridge Energy Project." Eversource, www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/greater-cambridge-energy-project.

Center Blue Garage. Above the underground substation will be an open and accessible public space. The project also requires five underground duct banks housing eight new 115-kilovolt (kV) transmission lines, interconnecting the new substation to an existing substation in the Allston-Brighton neighborhood of Boston, existing substations at Kendall, as well as Putnam Avenue in Cambridge and the existing substation at Prospect Street in Somerville. Station #8025 will provide additional capacity to the City of Cambridge, relieve the existing surrounding substations, including East Cambridge Putnam, and Somerville, and support future development, electrification and clean energy goals in the Greater Cambridge area. The project solution (with the future 4th bank) increases the area firm capacity supply by ~90 MW which will enable 88,000 new EVs or the equivalent of 18,000 residential heat pumps to be deployed in the service region.

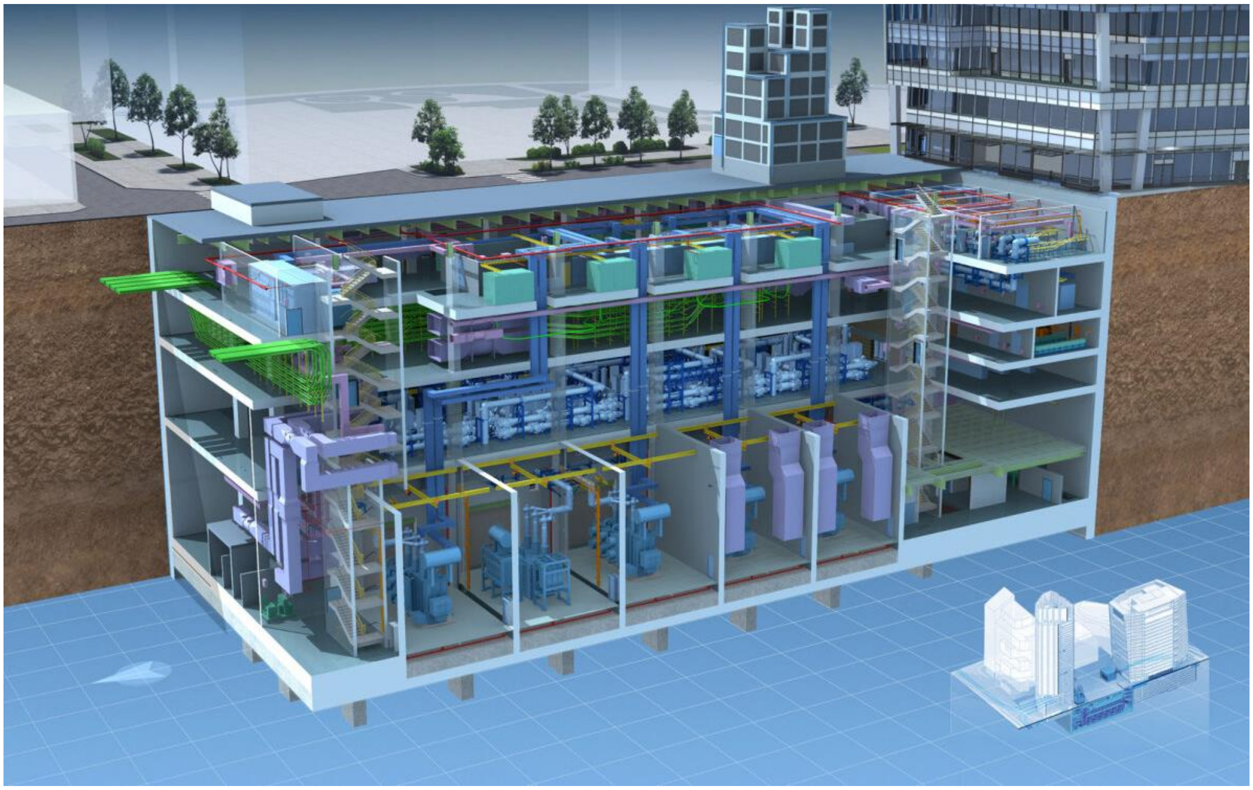


Figure 151: Conceptual Layout of East Cambridge Substation - Clean Energy Hub

- **City of Boston: Future Hyde Park – Dorchester Area Supply Initiatives** – As discussed earlier and shown in Table 46, the existing substations at Andrew Square, Hyde Park and Dorchester which serve the neighborhoods of South End, Roxbury, Dorchester, Jamaica Plain, Mattapan, Roslindale, Hyde Park, Dorchester, and Mattapan are all currently loaded to over 90% of firm capacity (Hyde Park is at 100%) and all will be at or over 100% loaded by 2030. The EPS infrastructure is stressed and cannot accommodate significant new development. A new substation is proposed at a location between Hyde Park and Dorchester, as shown in Figure 152 below, to bring additional capacity to the Hyde Park, Mattapan, Dorchester, and Roslindale areas. The objective of the new substation project is to relieve the heavily loaded Hyde Park Substation #496 and surrounding substations in the Dorchester area, and support future development, electrification, and clean energy goals in the Hyde Park-Dorchester area. The station would need to add ~150 MW of firm capacity, which roughly translates to a 3-transformer substation with standard size 37/60/62.5 MVA transformers. This will increase the area firm capacity supply by ~150 MW expandable to ~225MW, enabling 147,000 new EVs or the equivalent of 30,000 residential heat pumps to be deployed in the service region.

As mentioned earlier, Hyde Park Substation #496 is above 100% of the substation capacity and interim operational measures are needed to reduce the risk of customers being unserved. Load transfer and other traditional measures are described in Section 4.3.7. In addition, the Company is developing a targeted battery energy storage (BES) non-wires alternative (NWA) solution to address the near-term capacity needs at Hyde Park Substation #496. The BES NWA solution is future discussed in Section 6.5.2 below.

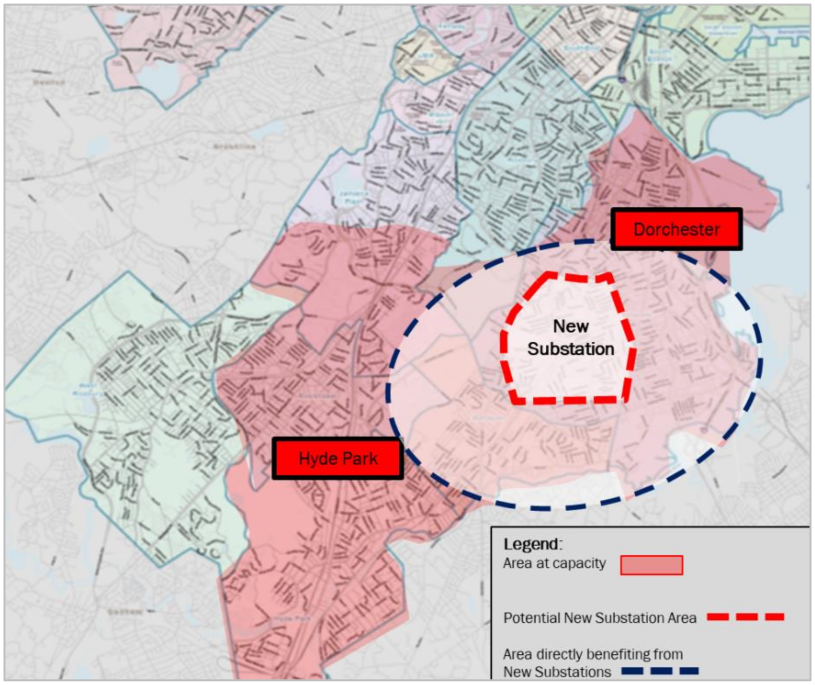


Figure 152: Proposed Location for New Hyde Park area Substation Showing Areas Benefitting

- **City of Somerville: Somerville 115/14kV Substation #402 Expansion** – As shown in Table 43the Somerville substation is currently loaded to 95% of the station firm capacity. The substation supplies the City of Somerville and the City of Cambridge. A third 37/60/62.5 MVA transformer and two distribution bus sections will be installed at Somerville

Substation #402 to increase capacity and provide contingency relief for Mystic Substation #250 and East Cambridge Substation #875. The upgrade is required to provide immediate capacity relief in areas experiencing large step load increase, such as Boynton Yards and Union Square in the City of Somerville and help support electrification and clean energy goals in the area. The project solution increases the substation firm capacity supply by ~75 MW which will enable 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

- **Bulk Distribution Transformer Additions** - Increase transformer capacity at an existing substation that has expansion capabilities. This additional capacity is being proposed to support local distribution load in the City of Cambridge North Cambridge area. It will expand the station firm capacity supply by ~75 MW which will enable 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region

6.5.1.3 Project Solutions 2030 - 2034

The following project solutions are being developed for needs manifest within the ten-year planning horizon but will be in service between 2030 and 2034. Any project solution that will be in service by 2029, are included in the prior section (Project Solutions 2025 - 2029). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

- **City of Boston: Boston Substation Supply Initiative** – The City of Boston is mostly supplied by 17 Distribution Bulk Substations. Two substations of these stations are not physically located in the city boundary (Everett and Chelsea) and six are network substations serving downtown areas (discussed in the next bullet). In total, there is approximately 2,500 MVA of substation capacity serving the City. Only two of the 17 substations (Seaport and Electric Ave) have expansion capability to help relieve nearby overloaded substations. Table 43 above, lists the 12 stations that are projected to be loaded above 90% by 2030, meaning they do not have sufficient ten-year capacity to meet expected load growth. Five of these stations are currently loaded to over 90% of firm, meaning customers served by these stations are currently at risk (Section 4.3.7 describes interim operation measures being taken to reduce the risk to customers).[164]

Four new substations are being proposed in the next ten years to support local distribution needs in the neighborhoods of: Charlestown/Somerville, South End, Allston/Fenway/Brookline, and Downton Boston. Widespread electrification in the Boston area cannot occur without completion of these project. These four substations which will be in service by 2034 and are

[164] It should be noted that a new substation is under construction in East Boston to relieve Chelsea station,

described below. A fifth substation needed in South Boston will be in service after 2034 and is described in Section 9 (2035 – 2050 Solution Set).

- **South End Substation** – As shown in Table 45, the neighborhoods of South End, Roxbury, and areas of Dorchester will all be at capacity within the next ten years and would not be able to accommodate new development. A new distribution bulk substation located in South End, supplied by multiple 115kV underground transmission lines, is needed for future development, such as Transportation Electrification area growth. Figure 153 below shows the approximate locations for the substations and the areas they would serve. Based on the typical size of substation capacity required for these needs, the project solutions increase the are firm capacity supply by ~150 MW (expandable to ~225MW) which will enable 147,000 new EVs or the equivalent of the equivalent of 30,000 residential heat pumps to be deployed in the service region.

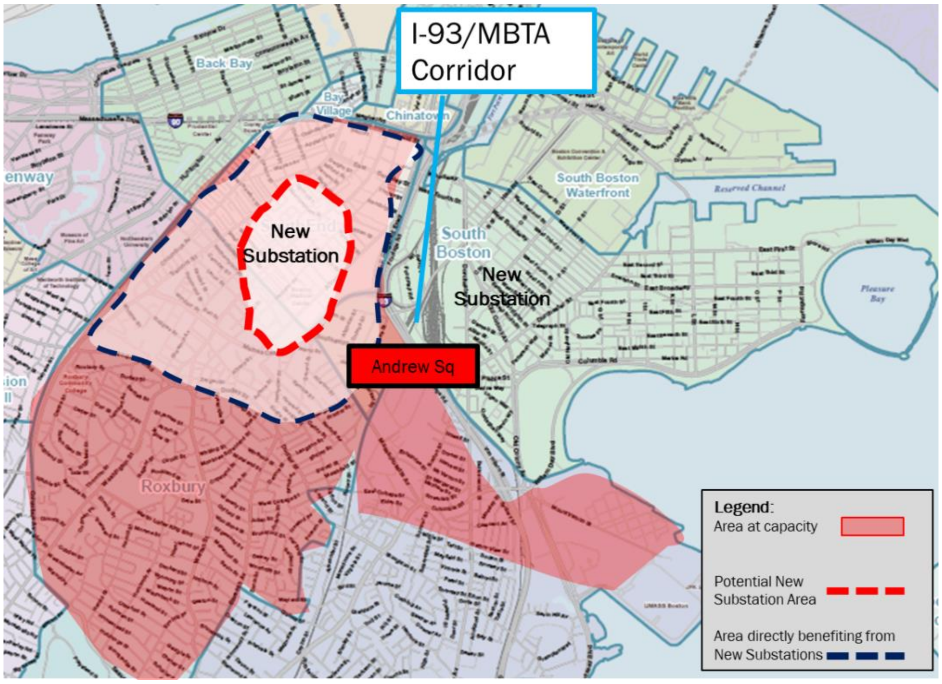


Figure 153: Locations of Needed South Boston Area Substations

- **Allston/Fenway/Brookline Substation** – As shown in Table 45, the Town of Brookline, the neighborhoods of Fenway, LMA, Mission Hill, and areas of Jamaica Plain will all be at capacity within the next ten years and would not be able to accommodate new development. A new distribution bulk substation located in the Town of Brookline (between Allston and Fenway), supplied by multiple 115kV underground transmission lines, is needed for future growth in Fenway and LMA areas. Figure 154 below shows the approximate location for the substation and the area it would serve. Based on the typical size of substation capacity required for this need, the project solution increases the are firm capacity supply by 150 MW (expandable to 225MW) which will enable 147,000 new EVs or the equivalent of 30,000 residential heat pumps to be deployed in the service region.

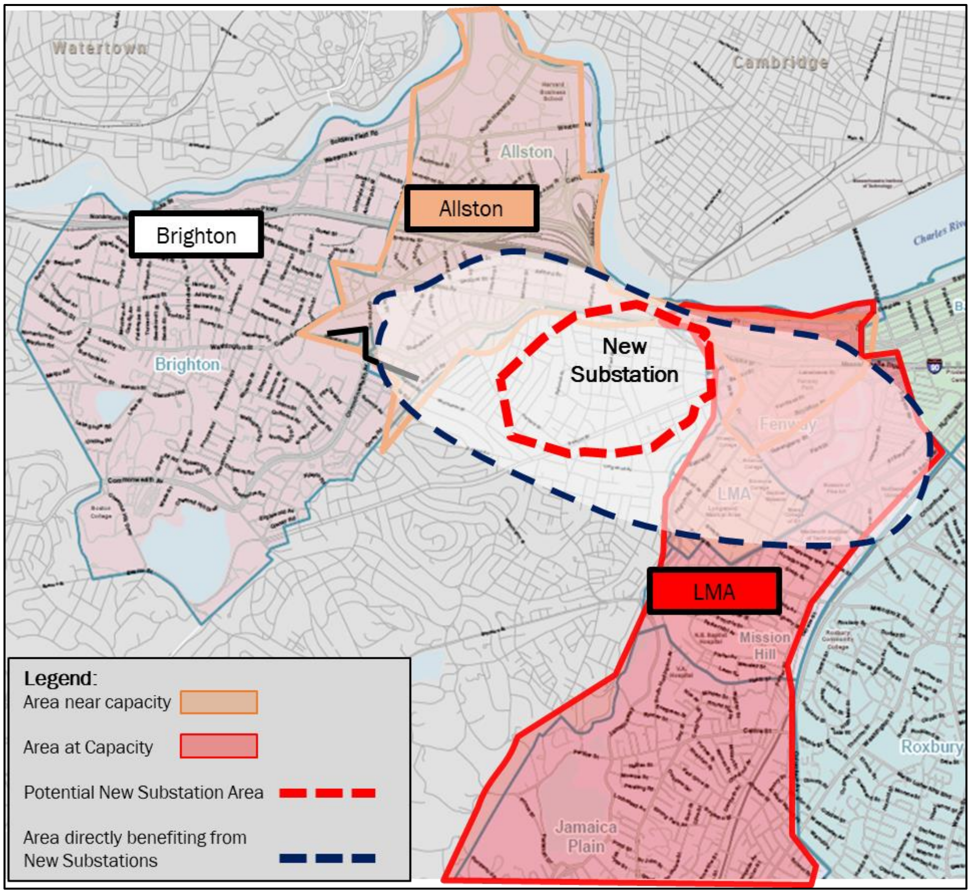


Figure 154: Location of Needed Allston Area Substation

- **Charlestown/Somerville Substation** – As shown in Table 45, the neighborhoods of Charlestown, areas of North End, and the City of Somerville are at capacity or will all be at capacity within the next ten years and would not be able to accommodate new development. A new distribution bulk substation located East or West of the I-93/MBTA corridor, supplied by multiple 115kV underground transmission lines, is needed to relieve Everett substation which is expecting future growth in transportation electrification. Figure 155 below shows the approximate location for the substation and the area it would serve. Based on the typical size of substation capacity required for this need, the project solution increases the are firm capacity supply by 150 MW (expandable to 225MW) which will enable 147,000 new EVs or the equivalent of 30,000 residential heat pumps to be deployed in the service region.

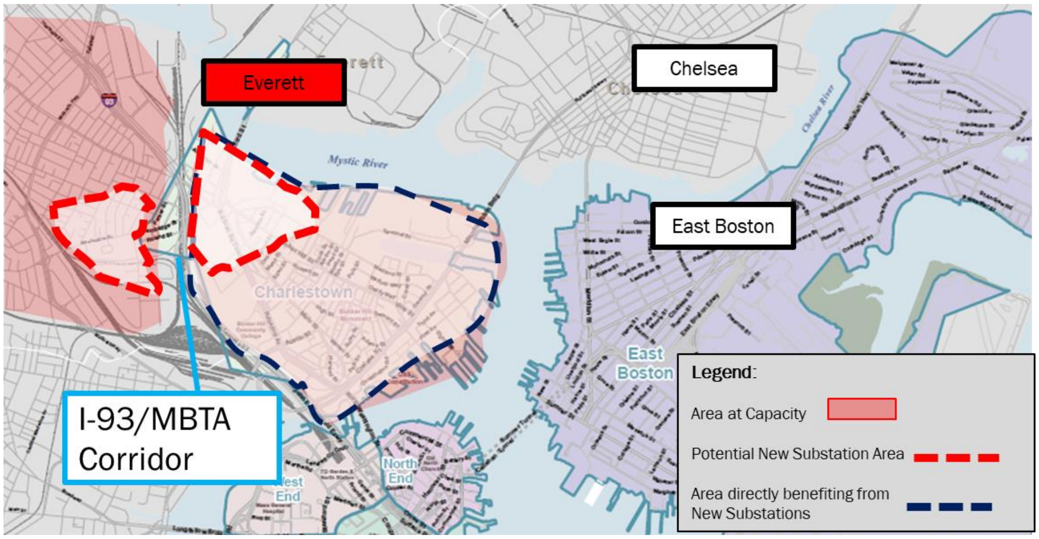


Figure 155: Location of Needed Charleston/East Boston Area Substation

- **City of Boston: Metro Boston Substation Supply Initiative**: The neighborhoods of Back Bay, Bay Village, Chinatown, Leather District, Downtown, Beacon Hill, West End, and North End are supplied by six underground (UG) network substations. The UG networked system is extremely reliable due to the meshed nature of the low voltage grid. Each of the six substations independently serves a network. As shown in Table 45, the neighborhoods of Bay Village, Back Bay, Beacon Hill, West End, North End, Chinatown, Leather District and Downtown will be at capacity within the next ten years and would not be able to accommodate new development. A new substation, supplied by multiple 115kV underground transmission lines, is being proposed to support local distribution loads in Downtown Boston, specifically the underground network areas in the neighborhoods of Beacon Hill, West End, North End, Chinatown, and the Leather District. Figure 156 below shows the approximate location for the substation and the area it would serve. Based on the typical size of substation capacity required for this need, the project solution increases the are firm capacity supply by 150 MW which will enable 147,000 new EVs or the equivalent of 30,000 residential heat pumps to be deployed in the service region.

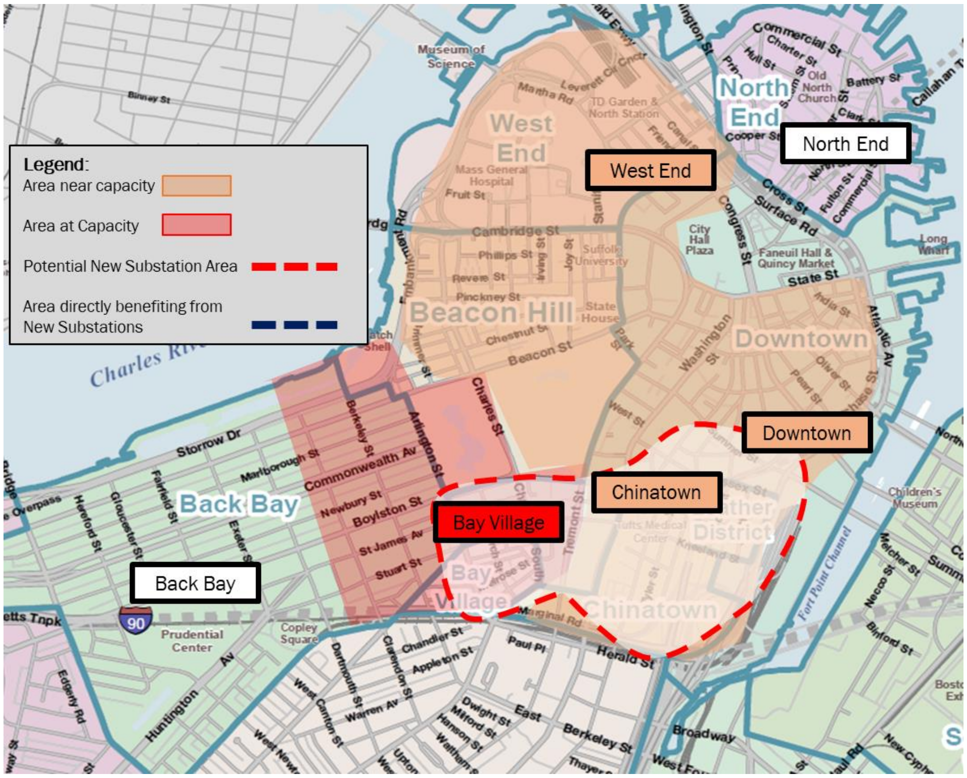


Figure 156: Location of Needed Network Substation

- **Bulk Distribution Transformer Additions** - Increase transformer capacity at existing substations that have expansion capabilities. This additional capacity is being proposed to support local distribution load in the City of Boston Brighton/Allston and Seaport areas.

6.5.2. Non-Wire Alternatives

As part of its distribution planning process, the Company actively looks for opportunities to apply non-wires alternative (NWA) solutions to meet suitable[165] distribution needs in alignment with the Company's established NWA Framework.[166] Where technically feasible and economically viable, NWA solutions can be used to modify the load shape or resolve technical constraints, in order to defer distribution level upgrades.

---

[165] An NWA solution is not considered to be suitable for resolving asset health issues or imminent issues such as a need appearing within less than 2 years.

In the Metro Boston region, the Company is planning to deploy a battery energy storage system (BESS)-based non-wires solution as an interim operational measure to help temporarily resolve capacity deficiencies in the Hyde Park substation service area, until the long-term project solution (a new substation) can be constructed. As discussed earlier and shown in Table 46, the Hyde Park station is at 100% and all will be over 100% loaded by 2030. The proposed BESS project will help relieve the heavy loading condition. The project can also potentially be used in the future to test other new applications/usages of the BESS. The project could demonstrate new BESS design/application ideas by connecting BESS system to various system voltage levels, (14kV and 25kV distribution systems); moving energy from one substation to the other when two systems cannot be directly connected; and testing partial discharging of the BESS while the remaining portion is charging with grid. Figure 157 shows the proposed location of the BESS at an Eversource-owned parcel. The project is currently going through the internal Company Capital Project Approval process.

Figure 157: Proposed Location of Hyde Park BESS

6.5.3. Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – Pros and Cons

Currently, there are no capital investment projects (CIPs) proposed or envisioned for solar PV in the EMA-North Metro Boston region. As discussed in Section 4.3.5, the Metro Boston region has a generally lower DER penetration for solar and solar coupled with battery storage (as a percentage of the region's peak load) and has the smallest share of solar applications in EMA due to the lack of available open space in this more highly developed portion of the Company's service territory. Capacity constraints and station saturation issues in EMA-North Metro Boston are primarily driven by load growth, rather than DER penetration, as observed in areas of EMA-South.

6.5.4. Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

There are no capital investment projects (CIPs) proposed or envisioned for standalone battery storage in the EMA-North Metro Boston region.

6.5.5. Equity and EJ outreach

The Company's EJ and equity outreach framework will be applicable to the Metro Boston Subregion and the overall framework is discussed in detail in Section 3.

6.6. EMA-North Metro West Sub-Region

The Eversource EMA-North Metro West Sub-Region consists of parts of thirty-five (35) Towns and Cities in Eastern Massachusetts served out of the Company's Southborough, Waltham, and Walpole Area Work Centers (AWC's). The region consists of portions of the Cities of Framingham, Newton, Waltham, Watertown, and Woburn, and surrounding Towns in Norfolk and Middlesex Counties. Some Towns served are jointly served with National Grid (Bellingham). The service area encompasses 417,292 customer accounts with high to medium load density areas, including heavy commercial and residential areas forming a ring along the Route 128/I-95 beltway around the Boston metropolitan area.

The detailed overview of forecasted demand for in Section 5 shows that over the next decade, the electric demand for the summer peak in the EMA-North Metro Boston Sub-Region is expected to go from 1859 MVA in 2023 to 2016 MVA in 2033, an increase of 8% over the planning horizon driven by a combination of step load additions and electric vehicle (EV) growth in the region. However, the growth in the last five years is driven more by EV as the forecast does not include information on step loads beyond five years.

To meet its obligation to provide reliable service to all customers, the Company has assessed the impact of 90/10 weather-normalized forecasted demand on each of its bulk distribution substations. This assessment is conducted on a yearly basis to evaluate impact of underlying load growth, as well as several adders that impact the peak demand and substation capacity constraints, including electrification trends. The following section details the system needs and major projects planned, proposed, or envisioned to safely and reliably meet those needs on a localized basis.

6.6.1. Major substation projects

6.6.1.1 Capacity and Reliability Needs

Through its annual capacity planning processes,[167] as summarized in Section 4.3.7 and reported in the ARR under DPU docket 23-ARR-02[168] and as reported in the Company's Rate Case Filing under DPU 22-22,[169] the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing or projected capacity and/or reliability deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations projected to be at capacity now or expected to be at capacity in the next 10-years.

Table 47 below presents a community-centric view of the capacity deficiencies. The table lists the communities in Metro West and the existing or projected substation supply deficiency by type (Reliability and/or Capacity) and timeframe for the need (substation at capacity now, at capacity within 5 years, at capacity within 10 years, at capacity beyond 10-year planning horizon).

Table 47: Metro West Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Burlington	Town	Middlesex	Capacity and Reliability	Now/Existing
Holliston	Town	Middlesex	Capacity and Reliability	Now/Existing
Lexington	Town	Middlesex	Capacity and Reliability	Now/Existing
Medway	Town	Norfolk	Capacity	Now/Existing
Millis	Town	Norfolk	Capacity and Reliability	Now/Existing
Norfolk	Town	Norfolk	Capacity	Now/Existing

[167] Refer to Section 4.1.6 for details on the capacity planning process.

Municipality	Type	County	Deficiency	Timeframe for Need
Acton	Town	Middlesex	Capacity and Reliability	Within 5 Years
Maynard	Town	Middlesex	Capacity and Reliability	Within 5 Years
Sudbury	Town	Middlesex	Capacity and Reliability	Within 5 Years
Woburn	City	Middlesex	Capacity and Reliability	Within 5 Years
Ashland	Town	Middlesex	Capacity and Reliability	Within 10 Years
Framingham	City	Middlesex	Capacity and Reliability	Within 10 Years
Hopkinton	Town	Middlesex	Capacity and Reliability	Within 10 Years
Natick	Town	Middlesex	Capacity and Reliability	Within 10 Years
Sherborn	Town	Middlesex	Capacity and Reliability	Within 10 Years
Wayland	Town	Middlesex	Capacity and Reliability	Within 10 Years
Weston	Town	Middlesex	Capacity and Reliability	Within 10 Years
Needham	Town	Norfolk	Capacity and Reliability	Beyond 10 Years
Newton	City	Middlesex	Reliability and Capacity	Beyond 10 Years
Waltham	City	Middlesex	Capacity and Reliability	Beyond 10 Years

Table 48 presents a substation-centric view of the capacity deficiencies. The table shows the substation name or location in the first column, followed by the community that is supplied by the substation. Some communities, such as Framingham, are supplied by multiple substations, so they will repeat for each substation.

The table also shows how constrained the substation is projected to be in 2030 compared to its thermal capacity rating. This number is shown as a percentage and is computed as the substation projected peak load divided by its capacity. A value greater than 100% is a violation of the Company planning criteria since the transformers' expected peak load will exceed the substation capacity. The last column on the table shows the associated 2025-2029 or 2030-2034 project solutions, later described in Sections 6.6.1.2 and 6.6.1.3, to address the projected overload.

Table 48: Metro West Substations with Projected Capacity Deficiencies and Communities Impacted

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.6.1.2 and 6.6.1.3)
Burlington	Burlington, Lexington, Woburn	**105%**	Future Burlington 115kV/14kV Substation
West Waltham (Waltham Ring)	Waltham	**102%**	Future Waltham Area Supply Initiatives
Maynard	Acton, Maynard, Sudbury	**101%**	Acton-Maynard Supply Initiatives and North Acton Supply Initiatives
West Medway (Medway Ring)	Holliston, Medway, Millis, and Norfolk	**100%**	Medway Substation #65 Upgrade
North Waltham (Trapelo Rd)	Waltham and Weston	**100%**	Future Waltham Area Supply Initiatives
Sherborn	Ashland, Framingham, Holliston,	**96%**	Future Saxonville or Natick 115/14kV

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.6.1.2 and 6.6.1.3)
	Hopkington, Natick, and Sherborn		Substation
East Sudbury (Sudbury Ring)	Framingham, Maynard, Sudbury, Wayland, and Weston	93%	Future Saxonville or Natick 115/14kV Substation
South Framingham (Framingham Ring)	Framingham, and Sherborn	91%	Future Saxonville or Natick 115/14kV Substation

The data shows that during the ten-year planning horizon, six additional substations (incremental to the ones identified in Section 4) are projected to have capacity and/or reliability violations. These are West Waltham, Maynard, North Waltham, Sherborn, East Sudbury, and South Framingham.

Through its annual capacity planning processes, as noted in the ARR, the Company goal is to have a *planning* solution for any substation expected to exceed 90% of its capacity during the ten-year planning horizon. However, despite the Company's best laid plans to develop and implement solutions for forecasted needs, there are times when the project implementation might miss the need date, due to a number of factors, primarily siting and permitting delays. When this occurs, the Company has an obligation to develop interim or emergency *operational* measures to ensure that customers are not unserved during an outage. These measures could include anything from load transfers to other substations via distribution ties, to temporary spot generation deployment, to development of non-wires alternatives such as battery storage where feasible. However, these options are only temporary measures and will be exhausted and ineffective as load continues to grow. A permanent planning solution must be implemented at some point to ensure long-term reliable service.

<u>Capacity Deficiencies due to DER Penetration</u>

Maynard-Acton DER Group – The Maynard-Acton Group comprises of one substation in EMA-North Metro West: Maynard #416. The substation ten-year forecasted peak load is 60 MVA and there is a total of 9 MW of installed ground mounted (large) DER, in addition to 10 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 12 MW of large DER, bringing the total DER penetration to 52% of peak load for the group. The proposed Group is expected to be fully subscribed over the 20-year recovery horizon as there is an estimated 935 MW of solar potential based on the technically developable land in the area. Figure 158 below shows the approximate geographical location of the substation and the geographic location served by the substation in the EMA-North Metro West Service Area. The proposed CIP solution is described in Section 6.6.1.3.

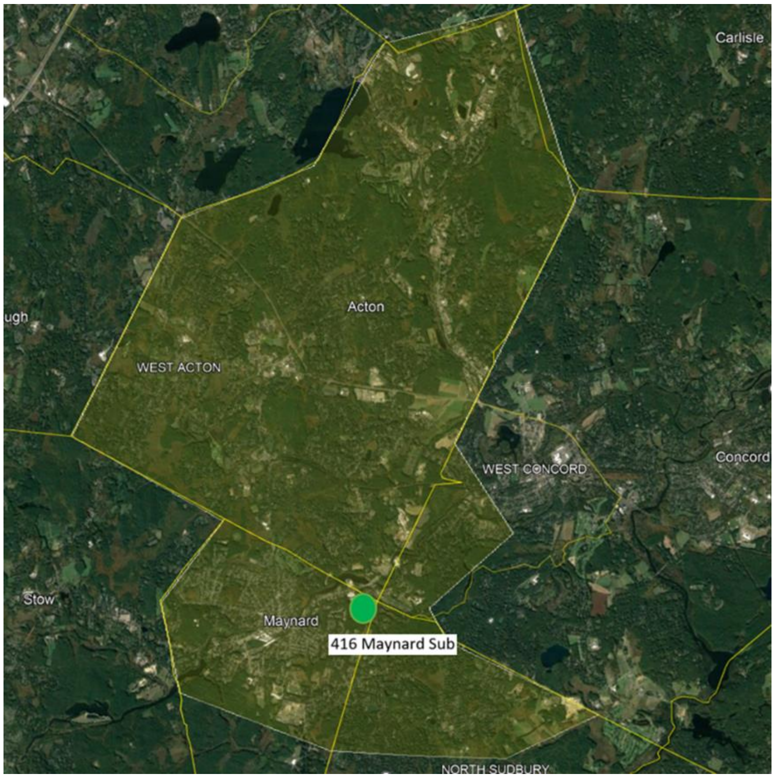


Figure 158: Maynard-Acton Group Study Area

Walpole-Sharon DER Group – The Walpole-Sharon Group comprises of one substation in EMA-North Metro West: Walpole #146. The substation ten-year forecasted peak load is 88 MVA and there is a total of 39 MW of installed ground mounted (large) DER, in addition to 15 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 15 MW of large DER, bringing the total DER penetration to 78% of peak load for the group. Based on the technically developable land in the area, there is 2 GW of solar potential; the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. Figure 159 below shows the approximate geographical location of the substation and the geographic location served by the substation in the EMA-North Metro West Service Area. The proposed CIP solution is described in Section 6.6.1.3.

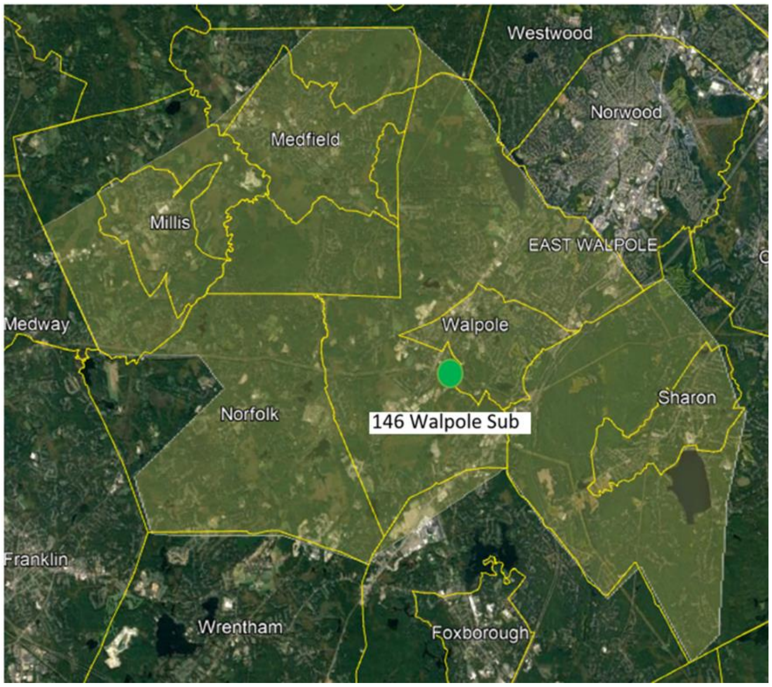


Figure 159: Walpole-Sharon Group Study Area

6.6.1.2 Project Solutions 2025 - 2029

Through its annual capacity planning processes, as summarized above, and reported in the ARR under DPU docket 23-ARR-02[170] and as reported in the Company's Rate Case Filing under DPU 22-22, the following projects have been either proposed or approved in the Company's Long Range Plan (LRP) for mitigation of identified capacity and/or reliability deficiencies on the EMA-North Metro West electric power system (EPS) discussed above.

All project solutions in this section are expected to be in service by 2029. Any project solution that will be in service after 2029, even if capital expenditure occurs before 2029, are included in the next section (Project Solutions 2030 - 2034). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

Future Burlington 115/14kV Substation[171] - As shown in Table 48, the 115/14kV transformers 110A and 110B are projected to be above 100% of the LTE rating for a contingency outage of either transformer bank. An interim emergency plan has been developed to install a mobile transformer at Burlington Station 391 by summer of 2023 until the long-term solution, a new

[170] Refer to Section 6.5.1
[171]Burlington to Woburn Supply Initiative." Eversource, www.eversource.com/content/residential/about/transmission-distribution/projects/massachusetts-projects/burlington-to-woburn-supply-initiative.

electrical substation in Burlington connecting to the existing electrical distribution network in the area, can be placed in service by the projected in-service date of 2028. The substation would be constructed on about two acres of Eversource-owned property accessed via Winn Street. Additionally, approximately 2.5 miles of new overhead transmission line and supporting structures would be installed in the existing rights-of-way running from the proposed new substation in Burlington through Wilmington into Woburn. The project is designed to improve the reliability of the electric system. Figure 160 below shows the approximate location of the new substation as well as existing and proposed transmission line routes. The project is critical to meeting the long-term capacity and reliability needs of the area and supporting the clean energy and electrification goals of the communities of Burlington, Lexington, Woburn. The station would need to add 75 MW of firm capacity, which roughly translates to a 2-transformer substation with standard 62.5 MVA transformers. This will increase the area firm capacity supply by 75 MW, enabling 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

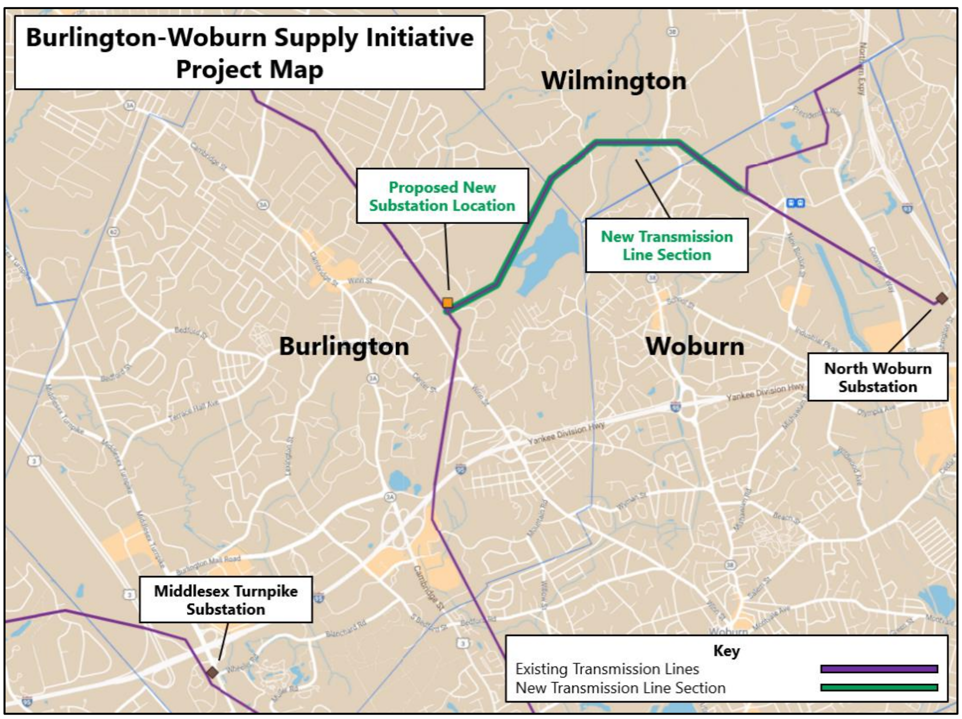


Figure 160: Burlington-Woburn Supply Initiative Project Map

Medway Substation #65 upgrade - Medway Station 65 is a double-ended station supplied by two 115/14kV, 40 MVA transformers and set up for automatic load restoration in a main-tie-main configuration. Upon loss of transformer unit 110A or unit 110B, the remaining in-service transformer continues to supply all the customer load until distribution system emergency transfer switching can take place. Due to historical load growth in the area, as discussed in Section 4 and 5, the 115/14kV, 40 MVA transformers 110A and 110B are approaching their LTE rating. The present system operating configuration has native Medway Station load temporarily supplied from Holliston Station 130. This interim operational measure maintains the existing loading on the station to less than the normal capacity of each transformer unit and the loading is monitored and alarmed via the SCADA (Supervisory Control and Data Acquisition) system. Additionally, as a second interim operational measure, a 50 MVA mobile transformer is pre-staged at Medway Station and is scheduled for installation in the fall of 2023. The long-term project solution is to replace the existing transformers, 110A and 110B, with new 62.5 MVA units and replace existing switchgear. The project scope will include installation of a new breaker on the high side (transmission) as well as some grounding and control upgrades. The project solution, expected to be implemented in 2024 - 2025, is critical to meeting the long-term capacity and reliability needs of the area and supporting the clean energy and electrification goals of the communities of Holliston, Medway, Millis, and Norfolk. The project will increase the are firm capacity supply by 20 MW which will enable 20,000 new EVs or the equivalent of 4,000 residential heat pumps to be deployed in the service region.

Acton-Maynard Supply Initiatives (Near-Term) - This project solution will increase bulk distribution substation capacity in the Acton-Maynard area where the existing substation is already over 95% of its capacity rating. Due to the current loading, this is an interim operational solution to temporarily increase capacity at Maynard substation. The station will increase the area firm capacity supply by 20MW, enabling 20,000 new EVs or the equivalent 4,000 residential heat pumps to be deployed in the service region.

6.6.1.3 Project Solutions 2030 - 2034

The following project solutions are being developed for needs manifest within the ten-year planning horizon but will be in service between 2030 and 2034. Any project solution that will be in service by 2029, are included in the prior section (Project Solutions 2025 - 2029). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

Future Saxonville/Natick 115/14kV Substation – The Company is looking at establishing a new 115/14kV bulk distribution substation near a transmission right-of-way between Saxonville Substation #278 and Framingham Ring Substation #240 to resolve forecasted loading at Sherborn, East Sudbury, and South Framingham Substations. The additional capacity is being proposed to support local distribution loads in the Framingham, Natick, and Holliston areas. The station will increase the area firm capacity supply by 75 MW (expandable to 150MW), enabling 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

North Acton Supply Initiatives - This is the long-term solution to relieve the existing substation which is already over 95% of its capacity rating. The interim operation measure (Acton-Maynard Supply Initiatives) was described above. The project solution could include a new bulk distribution substation to improve substation capacity and distribution system reliability in the Acton-Maynard-Carlisle area and support the clean energy and electrification goals of the communities of Acton, Maynard, Sudbury. The station will increase the area firm capacity supply by 75 MW (expandable to 150 MW), enabling 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

Future Waltham Area Supply Initiatives – The Company is looking at establishing a new 115/14kV bulk distribution substation to relieve the existing North and West Waltham Substations. The additional capacity is being proposed to support local distribution loads in the Waltham and Weston areas. The substation will increase the area firm capacity supply by 75MW (expandable to 150MW), enabling 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region, resulting in ZZ tons of GHG emission reduction.

<u>Solutions for DER Penetration Constraints</u>

- **Maynard-Acton Group CIP -** The Company is currently developing a Group Study solution for the 12 MW of DG applications in the Maynard-Acton area of the EMA-North Metro West region. A preliminary analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER. The initial assessment shows that upgrading the existing substation transformers and switchgear under Capital Project and the addition of one new Switchgear will enable approximately 53 MVA of DER, 41 MVA beyond the 12 MW in the Group Study. The upgrades will also enable future DER interconnections and help address any potential electrification and load growth needs. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee. Due to the amount of in-queue ground mounted DERs, thermal overload on distribution equipment is observed. For these violations on substation transformers and distribution circuits, the most common solution is to upgrade the existing equipment or to add new equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns. The Maynard substation is already double-ended and under Capital Project, the existing transformers will be upgraded with two Standard 62.5 MVA transformers with up to six feeders out of each substation bus. The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Maynard-Acton CIP.

The capacity for the Maynard-Acton CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 49 below. As a result of the substation upgrades identified in the Group Study, 53 MVA of Ground Mounted DERs could be reliably enabled – 41 MVA above and beyond the 12 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 53 MVA who pay a proposed (preliminary) fixed CIP fee of $657/kW can safely and reliably connect to the Maynard-Acton CIP substation, six new distribution feeders will be required for the future 41 MVA of DER beyond the group study. Figure 161 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 49: Maynard 416 Distribution Substation and Line Capacity Allocation

	Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)	
Substation	Maynard 416	63	0	10	53	41	Substation
		63	**0**	**10**	**53**	**41**	
		Capacity Allocation of Distribution Line between DER Customers and Load Customers					
Distribution Line	Stations	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)	Distribution Line
	Maynard 416	36	14	10	133	121	
		36	**14**	**10**	**133**	**121**	

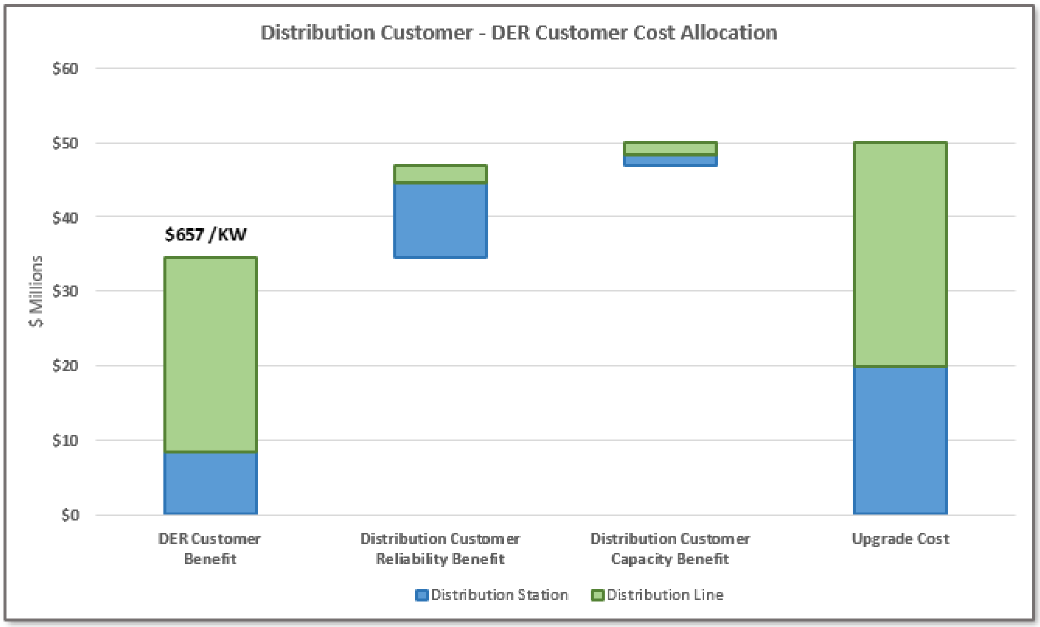


Figure 161: Maynard-Acton Cost Allocation and CIP Fee

- **Walpole Substation (Walpole-Sharon Group) -** The Company is currently developing a Group Study solution for the 15 MW of DG applications in the Walpole-Sharon area of the EMA-North Metro West region. A preliminary analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER. The initial assessment shows that adding a new switchgear will enable approximately 68 MVA of DER beyond the 15 MW in the Group Study. The switchgear upgrade will also enable the future DER interconnections and help address any potential electrification and load growth needs in the area. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee. Due to the amount of in-queue ground mounted DERs, thermal overload on distribution equipment is observed. For these violations, the most common solution is to upgrade the existing equipment or to add new equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns. The

Walpole substation is already triple-ended and the new switchgear addition will allow up to six feeders out of the substation bus. The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Walpole-Sharon CIP. The capacity for the Walpole-Sharon CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 50 below. As a result of the substation upgrades identified in the Group Study, 83 MVA of Ground Mounted DERs could be reliably enabled – 68 MVA above and beyond the 15 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 83 MVA who pay a proposed (preliminary) fixed CIP fee of $204/kW can safely and reliably connect to the Walpole-Sharon CIP substation, six new distribution feeders will be required for the future 68 MVA of DER beyond the group study. Figure 162 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 50: Walpole-Sharon CIP Substation and Distribution Line Capacity Allocation

		Capacity Allocation of Distribution Substation between DER Customers and Load Customers					
Substation	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)
	Walpole 146	125	63	0	15	83	68
		125	**63**	**0**	**15**	**83**	**68**

		Capacity Allocation of Distribution Line between DER Customers and Load Customers					
Distribution Line	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)
	Walpole 146	271	68	71	15	229	214
		271	**68**	**71**	**15**	**229**	**214**

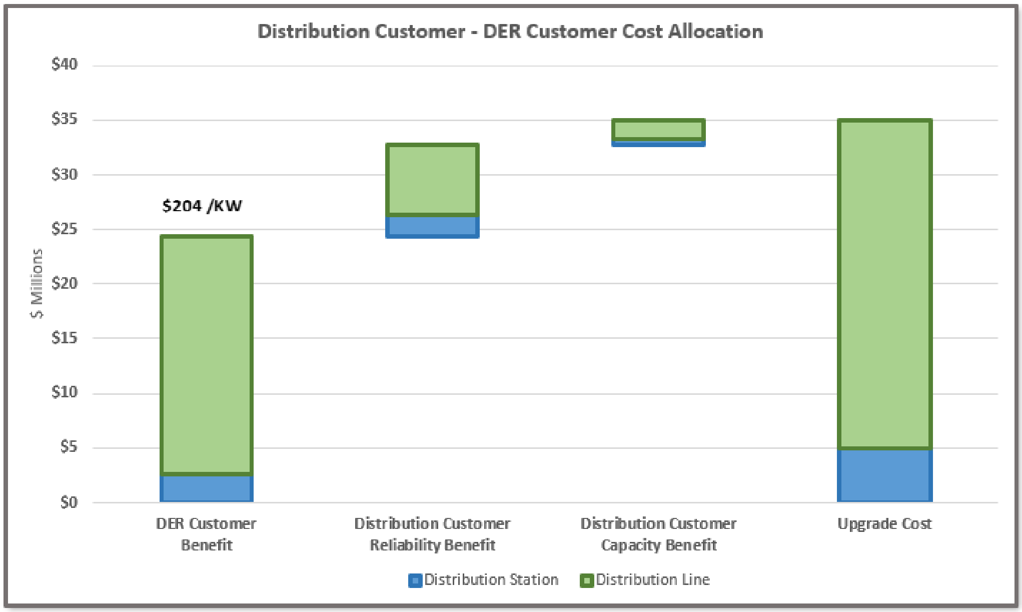


Figure 162: Walpole-Sharon Cost Allocation and CIP Fee

6.6.2. Non-Wire Alternatives

As part of its distribution planning process, the Company actively looks for opportunities to apply non-wires alternative (NWA) solutions to meet suitable[172] distribution needs in alignment with the Company's established NWA Framework.[173] Where technically feasible and economically viable, NWA solutions can be used to modify the load shape or resolve technical constraints, to defer distribution level upgrades.

Currently, the Company does not have an NWA solution planned for the EMA-North Metro West region. The Company is continually evaluating project needs and will continue to assess the viability of NWA solutions for suitable needs.

6.6.3. Alternative cost allocation approaches to interconnect solar projects – exploration of different approaches – pros and cons

As discussed in Section 4.4.5, even though the Metro West region has a generally higher DER penetration for solar and solar coupled with battery storage (as a percentage of the region's peak load) than the metro Boston region, capacity constraints and station saturation issues are primarily driven by load growth, rather than DER penetration, as observed in areas of EMA-South.

---

[172] An NWA solution is not considered to be suitable for resolving asset health issues or imminent issues such as a need appearing within less than 2 years

[173] Include link to public filing with NWA Framework

Currently, there are two Substations; Walpole and Maynard in the EMA-North Metro West region where the Company is planning to conduct group studies. At Walpole Substation, approximately 15.6 MW of DER are in queue and at Maynard Substation approximately 12 MW of DER are in the queue. These projects are a variety of solar and BESS projects either ac- or dc-coupled, or standalone storage. The Company intends to apply its cost allocation methodology to develop a CIP fee for the Maynard-Acton and Walpole-Sharon group study areas. The group studies are scheduled to be completed in the first quarter of 2024.

6.6.4. Alternative Cost Allocation Approaches to Interconnect Battery Storage Projects – Exploration of Different Approaches – Pros and Cons

There are no capital investment projects (CIPs) proposed or envisioned for standalone battery storage in the EMA-North Metro West region. However, it is possible that the enabled capacity in the proposed Maynard-Acton or Walpole-Sharon CIPs could be used by standalone battery projects, with similar CIP provisions as solar projects.

6.6.5. Equity and EJ Outreach

The Company's EJ and equity outreach framework will be applicable to the Metro West Subregion and the overall framework is discussed in detail in Section 3.

6.7. EMA-South Sub-Region

The Eversource EMA-South Region consists of all or parts of forty (40) Towns and Cities in Southeastern Massachusetts (SEMA) served out of the Company's New Bedford, Plymouth, Yarmouth, and Oak Bluffs Area Work Centers (AWC's). The region consists of the City of New Bedford and surrounding Towns in the Southern portion of Bristol County, the Town of Plymouth and surrounding Towns in the Southern portion of Plymouth County, all of Cape Cod (Barnstable County), and all of Martha's Vineyard (Dukes County). Some Towns served are jointly served with National Grid (Westport, Scituate, and Pembroke) or Municipal Electric Departments (Lakeville). The region is quite diverse with some moderate to low load density areas, some industrial and heavy commercial load in Cities like New Bedford extensive highly rural, protected areas with little to no customers and resort/tourist areas with high seasonal summer peak loads.

The detailed overview of forecasted demand for in Section 5 shows that over the next decade, the electric demand for the summer peak in the EMA-North Metro Boston Sub-Region is expected to go from 1,212 MVA in 2023 to 1,256 MVA in 2033, an increase of 4% over the planning horizon driven predominantly by EV growth.

To meet its obligation to provide reliable service to all customers, the Company has assessed the impact of 90/10 weather-normalized forecasted demand on each of its bulk distribution substations. This assessment is conducted on a yearly basis to evaluate impact of underlying load growth, as well as several adders that impact the peak demand and substation capacity constraints, including electrification trends. The following section details the system needs and major projects planned, proposed or envisioned to safely and reliably meet those needs on a localized basis.

6.7.1. Major Substation Projects

6.7.1.1 Capacity and Reliability Needs

Through its annual capacity planning processes[174] and reported in the ARR under DPU docket 23-ARR-02[175] and as reported in the Company's Rate Case Filing under DPU 22-22,[176] the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing or projected capacity[177] and/or reliability[178] deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations projected to be at capacity now or expected to be at capacity in the next 10-years.

Table 51 below presents a community-centric view of capacity deficiencies. The table list the communities in EMA-South and the existing or projected substation or distribution line supply deficiency by type (Reliability and/or Capacity) and timeframe for the need (substation at capacity now, at capacity within 5 years, at capacity within 10 years, at capacity beyond 10-year planning horizon).

Table 51: EMA-South Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Bourne	Town	Barnstable	Capacity	Now/Existing
Falmouth	Town	Barnstable	Capacity	Now/Existing
Mashpee	Town	Barnstable	Capacity	Now/Existing
Aquinnah	Town	Dukes	Capacity and Reliability	Now/Existing
Chilmark	Town	Dukes	Capacity and Reliability	Now/Existing
West Tisbury	Town	Dukes	Capacity and Reliability	Now/Existing
Tisbury	Town	Dukes	Capacity and Reliability	Now/Existing
Oak Bluffs	Town	Dukes	Capacity and Reliability	Now/Existing
Edgartown	Town	Dukes (seat)	Capacity and Reliability	Now/Existing
Brewster	Town	Barnstable	Capacity and Reliability	Beyond 10 Year

[174] Refer to Section 4.1.6 for details on the capacity planning process
[175] See Footnote 31 in Section 6.5.1
[176] See Footnote 32 in Section 6.5.1
[177] See Footnote 33 in Section 6.5.1
[178] See Footnote 34 in Section 6.5.1

Municipality	Type	County	Deficiency	Timeframe for Need
Dennis	Town	Barnstable	Capacity and Reliability	Beyond 10 Year
Harwich	Town	Barnstable	Capacity and Reliability	Beyond 10 Year

Table 52 below presents a substation-centric view of capacity deficiencies. The table shows the substation name or location in the first column, followed by the community that is supplied by the substation. The table also shows how constrained the substation is projected to be compared to its substation thermal capacity. This number is shown as a percentage and is computed as substation projected peak load divided by the substation capacity. A value greater than 100% is a violation of the company planning criteria since the transformers' expected peak load will exceed the substation capacity. The last column on the table shows the associated 2025-2029 or 2030-2034 project solutions, later described in Sections 6.7.1.2 and 6.7.1.3, to address the projected overload.

Table 52: EMA-South Substations with Projected Capacity Deficiencies and Communities Impacted

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.7.1.2 and 6.7.1.3)
Harwich	Brewster, Dennis, and Harwich	**102%**	Future Dennis-Brewster Substation
East Falmouth	Bourne, Falmouth, and Mashpee	**89%**	Future Falmouth Tap #924 Substation

Currently 1 of 29 substations supplying the EMA-South area have a capacity and/or reliability violation, and during the ten-year planning horizon one additional substation, for a total of 2 of 29 substations, is projected to have capacity and/or reliability violations. This includes the substations supplying the Brewster, Dennis, and Harwich areas that are expected to be loaded near or above 90 percent of capacity within the ten-year Planning Horizon. The substation supplying this area is of special concern because of the long distance of the existing distribution feeders which decreases reliability for all customers supplied by the substation. Moreover, due to the amount of time that it will take to site and permit a new substation in this area, a solution could take more time to implement than in any other area of Massachusetts.

Through its annual capacity planning processes, as noted in the ARR, the company goal is to have a solution for any substation expected to exceed 90% of its capacity during the ten-year planning horizon. However, despite the Company's best laid plans to develop and implement solutions for forecasted needs, there are times when the project implementation might miss the need date, due to several factors, primarily siting and permitting delays. When this occurs, the Company has an obligation to develop interim or emergency *operational* measures to ensure that customers are not unserved during an outage. These measures could include anything from load transfers to other substations via distribution ties, to temporary spot generation deployment, to development of non-wires alternatives such as battery storage where feasible. However, these options are only temporary measures and will be exhausted and ineffective as load continues to grow. A permanent planning solution must be implemented at some point to ensure long-term reliable service.

Capacity Deficiencies due to Distribution Line Constraints

Martha's Vineyard 5th Cable – This solution is needed to address capacity issues supplying Martha's Vineyard and to allow retirement of five vintage 2.5 MW diesel generators on the island (vintage 1940 and 1970's). This solution also supports the Martha's Vineyard Commission Climate Action Task Force (MV/CAT) goals for future electrification of fossil fuel end uses (vehicles, heating, etc.) on the island.

Capacity Deficiencies due to DER Penetration[179]

DPU 22-47 (Marion-Fairhaven Group Study)[180] – The Marion-Fairhaven Group comprises of four substations in Southeastern Massachusetts (SEMA): Arsene Street (Substation #654); Crystal Spring (Substation #646); Rochester (Substation #745); and Wing Lane (Substation #624). These substations collectively serve 57 MVA of customer peak load. There is a total of 60 MW of installed ground mounted (large) DER, in addition to 10 MW rooftop (small) DER on the four stations, and the Group Study will interconnect another 49 MW of large DER, bringing the total DER penetration to 209% of peak load for the group. Figure 163 below shows the approximate geographical location, in the EMA-South service area, served by the four substation substations in the group. The proposed CIP solution is described in the next section.

[179] Refer to Provisional System Planning Program Guide | Mass.gov
[180] Refer to DPU 22-47 Exhibit ES-Engineering Panel-1; Approved by the Department December 2022

Figure 163: Marion-Fairhaven DER Group Approximate Boundary

DPU 22-51 (Freetown Group Study)[181] – Freetown Group Study Solution comprises of one substation in Southeastern Massachusetts (SEMA): Assonet (Substation #647). This substation is currently supplied by Bell Rock #647, a National Grid bulk substation, with an Eversource-owned 115/34.5 kV transformer that supplies two 34.5/13.2 kV 15 MVA transformers at the Assonet substation via a single 34.5 kV line. The Assonet substation serves 9 MVA of customer peak load. There is a total of 11 MW of installed ground mounted (large) DER, in addition to 2 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 22 MW of large DER, bringing the total DER penetration to 389% of peak load for the group.[182] Figure 164 below shows the approximate geographical location, in the EMA-South service area, served by the two substation substations in the group. The proposed CIP solution is described in the next section.

[181] Refer to DPU 22-51 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023
[182] The approximately 22 MW of DER consists of 6 different facilities from 4 applicants.

Figure 164: Freetown DER Group Approximate Boundary

DPU 22-53 (Dartmouth-Westport Group Study)[183] – The Dartmouth-Westport Group Study Solution is comprised of two substations in Southeastern Massachusetts (SEMA): Cross Road (Substation #651) and Fisher Road (Substation #657). The substations collectively serve 64 MVA of customer peak load. There is a total of 61 MW of installed ground mounted (large) DER, in addition to 11 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 16 MW of large DER, bringing the total DER penetration to 136% of peak load for the group.[184] Figure 165 below shows the approximate geographical location of the two substations, and the geographic location served by the substations, in the EMA-South Service Area. The proposed CIP solution is described in the next section.

---

[183] Refer to DPU 22-53 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023
[184] The approximately 16 MW of DER consists of 6 different facilities from 5 applicants.

EVERSOURCE

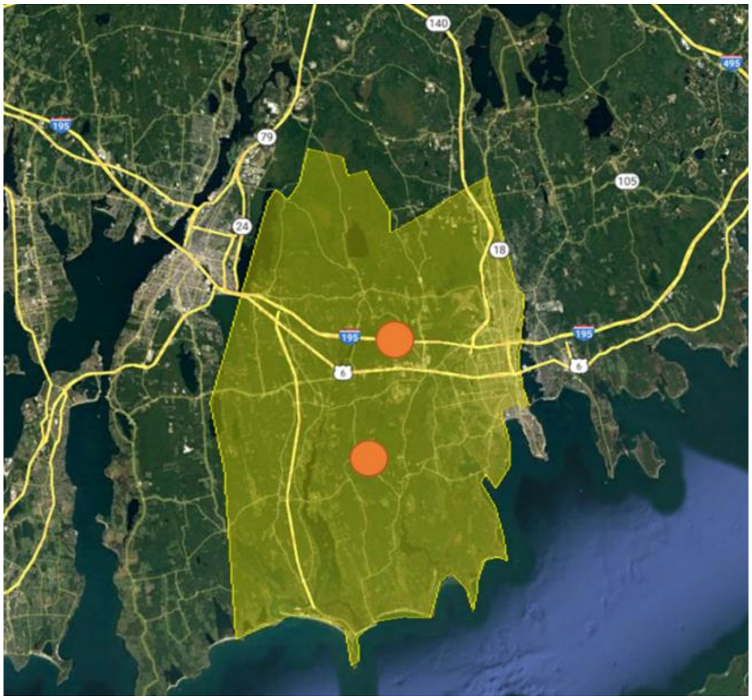


Figure 165: Dartmouth-Westport DER Group Approximate Boundary

DPU 22-54 (Plymouth Group Study)[185] – The Plymouth Group comprises of seven substation in Southeastern Massachusetts (SEMA): Tremont (Substation #713), Wareham (Substation #714), West Pond (Substation #737), Valley (Substation #715), Manomet (Substation #721), Kingston (Substation #735), and Brook St (Substation #727). These substations collectively serve 229 MVA of customer peak load. There is a total of 202 MW of installed ground mounted (large) DER, in addition to 35 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 123 MW of large DER, bringing the total DER penetration to 157% of peak load for the group. Figure 166 below shows the approximate geographical location of the seven substations, and the geographic location served by the substations, in the EMA-South Service Area. The proposed CIP solution is described in the next section.

[185] Refer to DPU 22-54 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023

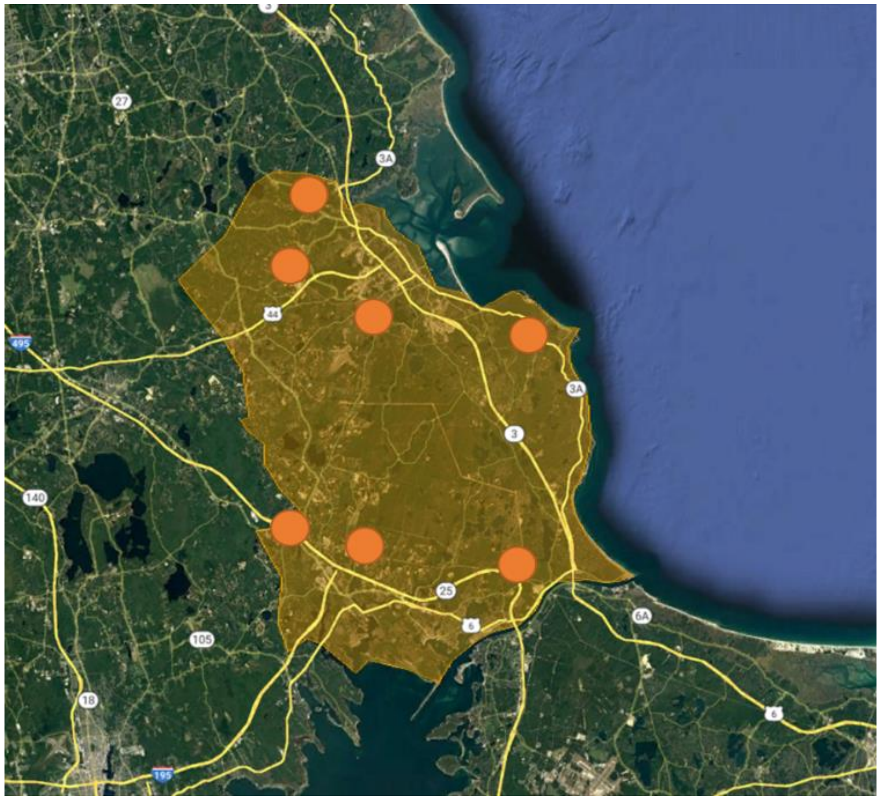


Figure 166: Plymouth DER Group Approximate Boundary

DPU 22-55 (Cape Group Study)[186] – The Cape Group comprises of eight substations in Southeastern Massachusetts (SEMA): Falmouth #933, Harwich #968, Hatchville #936, Hyannis Junction #961, Sandwich #916, Oak St #920, Mashpee #946, and Otis #915. These substations collectively serve 461 MVA of customer peak load. There is a total of 103 MW of installed ground mounted (large) DER, in addition to 46 MW of rooftop (small) DER on the substations, and the Group Study will interconnect another 71 MW of large DER, bringing the total DER penetration to 48% of peak load for the group. Figure 167 below shows the approximate geographical location of the eight substations, and the geographic location served by the substations, in the EMA-South Service Area. The proposed CIP solution is described in the next section.

[186] Refer to DPU 22-55 Exhibit ES-Engineering Panel-1; Pending Department's decision as of August 2023

Figure 167: Cape DER Group Approximate Boundary

East Freetown Group (Formerly New Bedford Group) – A solution is needed to increase the hosting capacity in the area, enable increased and timely adoption of proposed renewable energy and DERs, promote energy storage and electrification technologies, and improve grid reliability and resiliency. The existing Industrial Park substation has 51 MW of installed DER with another 39 MW in the queue. Over a 20-year period, the DER forecasted to be developed in the area is far beyond the existing queue. Therefore, based on the of 2.2 GW potential of technically developable land in the area the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. The New Bedford group Study that was conducted under D.P.U. 20-75 revealed that the Industrial Park substation cannot integrate the 39 MW of DER in-queue without significant substation and distribution line capacity, voltage and power quality violations. The group study solution for New Bedford included upgrading both existing transformers at Industrial Park Substation to 37/50/62.5 MVA transformers, adding a 3rd 37/50/62.5 MVA transformer, installing a 115kV ring bus at the substation to allow installation of the 3rd transformer without planning criteria violations, installing a 20MVAR D-VAR (Dynamic Volt-Amp Reactive) device at the substation to mitigate excessive load-tap-change (LTC) tap operations and voltage flicker, installing several new 13.2kV bus sections for additional distribution feeders to be constructed, constructing five new 13.2kV distribution feeders (three with substantial underground construction for several miles), installing additional pole-mounted voltage regulators, upgrading substantial portions of the distribution system to extend three-phase primary service to single-phase areas where many of the group study applicants are interconnecting, installing VVO (Volt-VAR Optimization) schemes on three transformers to regulate distribution system voltage and developing requirements for integration into a DERMS (Distributed Energy Resource Management System) platform. The total cost of all upgrades resulted in a CIP fee of over \$800/kW, significantly more than the \$500/kW threshold specified under the DPU 20-75-B order. Consequently, after consultation with the group members, a CIP proposal was not submitted for the New Bedford Group. The new East Freetown Group has been formed to develop a more comprehensive solution for the load and DER growth in the area between the existing Industrial Park substation in New Bedford and the Assonet Substation in Freetown. The group solution and cost allocation methodology are based on the updated approach described earlier in Section 6.1.4. The proposed solution (described in the following section) includes a substation located much closer to the cluster of group study DER, and would have substantially lower costs, making it a more technically and economically viable solution. The approximate boundary of the CIP area and the locations of the Industrial Park substation and proposed new East Freetown substation are shown below in Figure 168. The proposed CIP solution is described in Section 6.7.1.3.

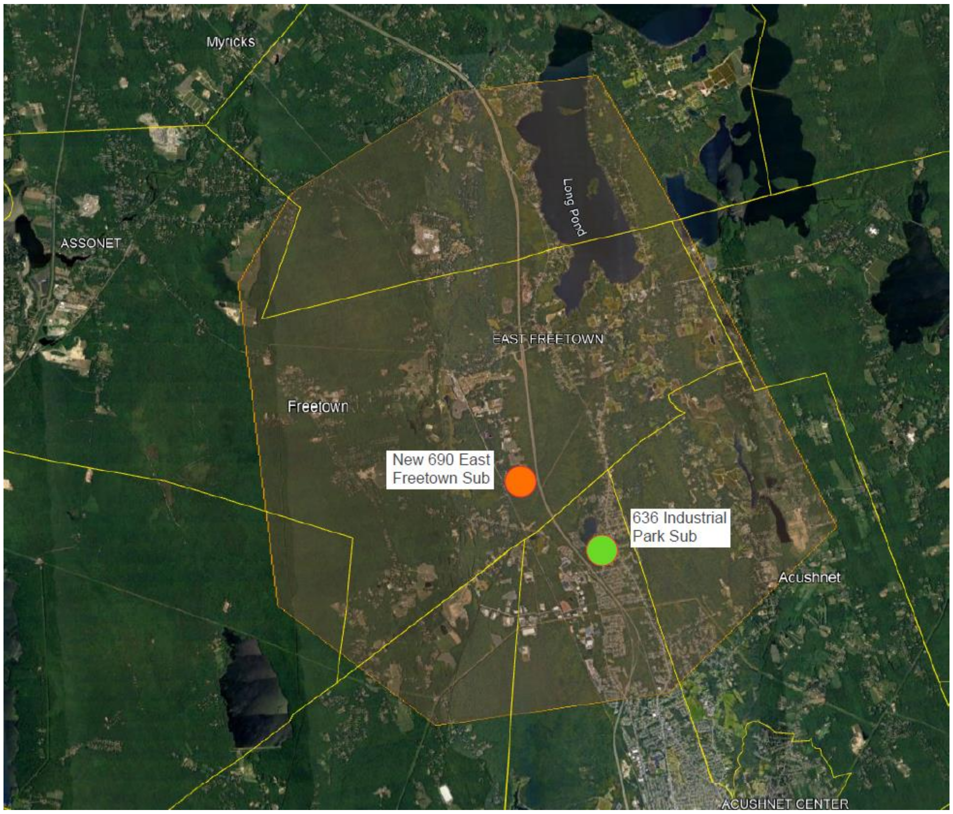


Figure 168: New Freetown Group Approximate Boundary

6.7.1.2 Project Solutions 2025 – 2029

Through its annual capacity planning processes as reported in the Annual Reliability Report under DPU docket 23-ARR-02[187] and as reported in the Company's Rate Case Filing under DPU

[187] See Footnote 24 in Section 4.3.7

22-22[188], the following projects have been either proposed or approved for mitigation of identified capacity or reliability deficiencies on the EMA-South electric power system as discussed above.

All project solutions in this section are expected to be in service by 2029. Any project solution that will be in service after 2029, even if capital expenditure occurs before 2029, are included in the next section (Project Solutions 2030 – 2034). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

- **Future Falmouth Tap #924 Substation** – Eversource is currently in the design and permitting stages for a rebuild of the existing Falmouth Tap #924 115kV switching station into a 115kV breaker-and-a-half scheme and with provision for a new 115/23kV bulk distribution substation to serve the North Falmouth, Hatchville, and South Bourne areas. The need is based on a number of N-1 and N-1-1 contingency events on the transmission and distribution systems. The upgrade is expected to be in service around year 2026 timeframe. 169 below shows the potential location of the new station. The station upgrade will increase transfer capacity supply in the area by 75 MW which will enable 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

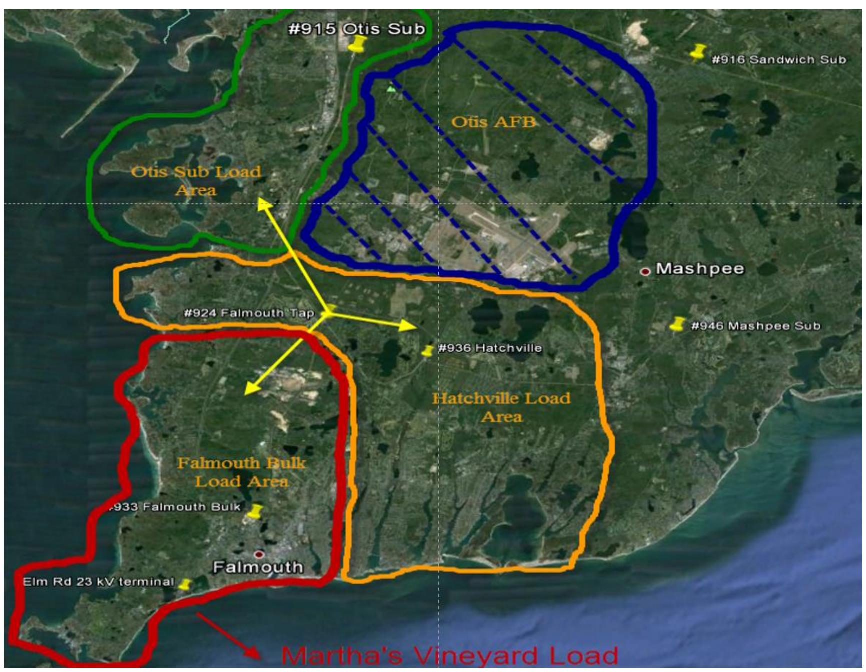


Figure 169: Future Falmouth Tap Substation Location

---

188 See Footnote 25 in Section 4.3.7

EVERSOURCE

Solutions for Distribution Constraints

- **Martha's Vineyard 5th Cable** – Eversource is currently in the permitting and design stages for installation of a 5th 23kV submarine cable to supply Martha's Vineyard which will resolve identified deficiencies in supply to the island.[189] This is part of the Martha's Vineyard Reliability Project[190] which will include the installation of a new 2.7-mile underground manhole (precast concrete vault) and duct bank system (a series of conduits that house electric cables). The proposed route runs from the existing Falmouth Station on Stephens Lane to Jones Road, onto the Shining Sea Bikeway, down Mill Road to Surf Drive before transitioning in the Surf Drive parking lot to a submarine cable to cross Vineyard Sound. The line will then travel 6.1 miles buried in the sea floor of Vineyard Sound before landing at East Chop, on Eastville Avenue where it will transition to onshore cables. Once onshore, the line follows a new duct bank and manhole system along Eastville Avenue to an Eversource parcel. Figure 170 below shows the location and approximate route of the cable. The upgrade, which is expected to be complete by end of 2024, will increase firm capacity supply to the island by 25 MW which will enable 24,500 new EVs or the equivalent of 5,000 residential heat pumps to be deployed in the service region.

[189] A conjunctional reliability project to replace one of the existing cables (#91) cable with a larger new cable is also on-going and is expected to be completed within the same timeframe. Both the capacity and reliability projects are needed to achieve the MV/CAT goals.

[190] Refer to [Martha's Vineyard Reliability and 91 Cable Replacement Projects | Eversource]

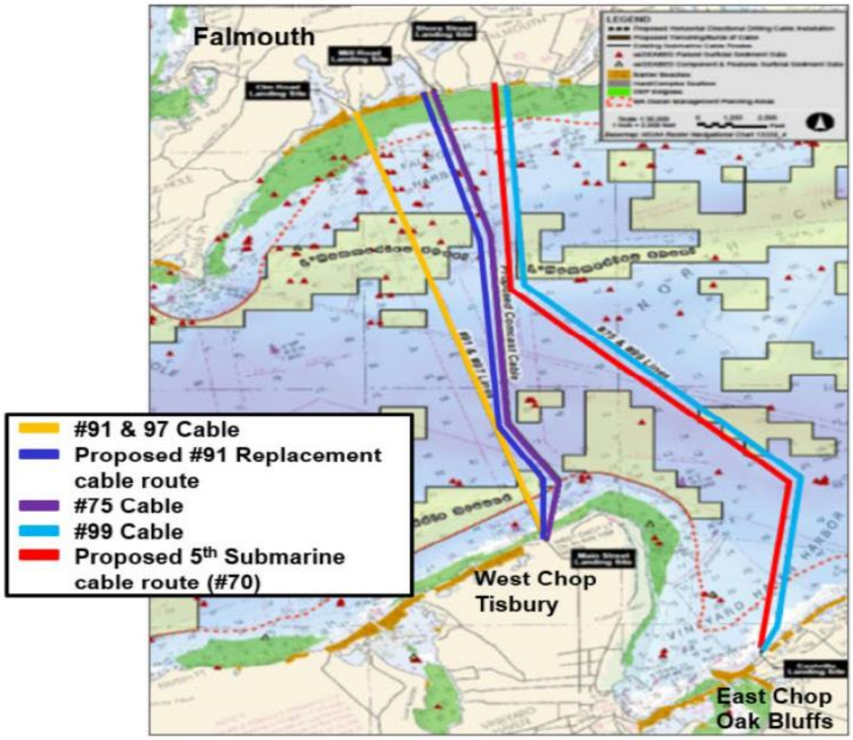


Figure 170: Location of Existing Cables and Approximate Route of Martha's Vineyard Fifth Cable

<u>Solutions for DER Penetration Constraints</u>[191]

- **DPU 22-47 (Marion-Fairhaven Group Study) CIP** – Three substations serving the Towns of Fairhaven, Acushnet, Mattapoisett, Rochester, and Marion, including Wing Lane Substation #624, Crystal Spring Substation #646, and Rochester Substation #745, require complete upgrades with replacement of six existing transformers (two new 37/50/62.5 MVA transformers at each substation), new 13.2kV metalclad switchgear to permit additional 13.2kV feeders, a new 115kV transmission line, additional 13.2kV feeders to address DER penetration, and associated additional 13.2kV distribution upgrades as identified in the Group Study. The upgrades permit the interconnection of 49 MW of Group Study DER applicants, permits 152 MW of future DG enablement, and 137 MW of future electrification.[192] This CIP has been approved in docket DPU 22-47. The resulting CIP fee for the group is $370/kW.

[191] D.P.U 22-47 was approved by the Department on December 2022, the remaining projects (D.P.U 22-51 to D.P.U 22-55) are pending a decision from the Department; Refer to Provisional System Planning Program Guide | Mass.gov for additional information

[192] Table 2, page 40, DPU 22-47 Exhibit ES-Engineering Panel-1

- D**PU 22-51 (Freetown Group Study) CIP** – Two substations serving the Town of Freetown (Assonet area), including Bell Rock Road Substation #661 (a bulk substation) and Assonet Substation #647 (a medium voltage distribution substation), will be rebuilt to provide a new 115/13.8kV bulk distribution substation to supply the Assonet area, with the existing 115/34.5kV system between Bell Rock Road and Assonet to be retired. Two new incoming 115kV underground transmission lines will be required, a new double-ended station with two 37/50/62.5 MVA transformers to be constructed on an existing site in Assonet, with new 13.2kV metalclad switchgear to permit the interconnection of additional 13.2kV feeders. The upgrades permit the interconnection of 22 MW of Group Study DER applicants, permits 54 MW of future DG enablement, and 54 MW of future electrification.[193] This CIP is still pending approval in docket DPU 22-51. The proposed CIP fee for the group is $490/kW.

- **DPU 22-53 (Dartmouth-Westport Group Study) CIP** – Two substations serving the Towns of Dartmouth, Westport, and portions of the City of New Bedford, including Cross Road Substation #651 and Fisher Road Substation #657. Fisher Road Substation will be completely rebuilt with two new 37/50/62.5 MVA transformers and new 13.2kV metalclad switchgear and two new 13.2kV feeders will be constructed out of the substation to interconnect Group Study DER. Cross Road Substation #651 is having series reactors installed for fault current mitigation (as a capital project). The upgrades permit the interconnection of 16 MW of Group Study DER applicants, permits 71 MW of future DG enablement, and 43 MW of future electrification.[194] This CIP is still pending approval in docket DPU 22-53. The proposed CIP fee for the group is $387/kW.

- **DPU 22-54 (Plymouth Group Study) CIP** – Seven substations serving the Plymouth District Towns of Wareham, Plymouth, Carver, Plympton, Kingston, Duxbury, (and small portions of Marion and Rochester), including: Tremont Substation #713, Wareham Substation #714, West Pond Substation #737, Valley Substation #715, Manomet Substation #721, Kingston Substation #735, and Brook Street Substation #727. Upgrades will be required at the Wareham #714, Tremont #713, and West Pond #737, including the replacement of five existing transformers with new 45/60/75 MVA 115/23kV transformers and the expansion of Tremont #713 and West Pond #737 with (2) additional 45/60/75 MVA transformers. New metalclad 23kV switchgear will be installed at Tremont #713 and West Pond #737 to permit the installation of additional 23kV feeders for Group Study DER interconnections. The upgrades permit the interconnection of 123 MW of Group Study DER applicants, permits 390 MW of future DG enablement,

[193] Table 2, page 41, DPU 22-51 Exhibit ES-Engineering Panel-1
[194] Table 2, Page 39, DPU 22-53 Exhibit ES-Engineering Panel-1

and 82 MW of future electrification.[195] This CIP is still pending approval in docket DPU 22-54. The proposed CIP fee for the group is $224/kW.

- **DPU 22-55 (Cape Group Study) CIP** – Eight substations serving the Cape District Towns of Bourne, Falmouth, Barnstable, Yarmouth, Harwich, Brewster, Dennis, Chatham, Hyannis, Sandwich, Mashpee, Tisbury, W. Tisbury, Oak Bluffs, Edgartown, Chilmark, and Aquinnah. The substations include: Falmouth #933, Harwich #968, Hatchville #936, Hyannis Jct. #961, Sandwich #916, Oak Street #920, Mashpee #946, and Otis #915. Three substations (Harwich #968, Hatchville #936, and Oak Street #920) will need minor upgrades to load tap changer (LTC) controls and there are required distribution circuit conductor upgrades on 23kV and 4kV circuits out of various stations required as part of the Group Study, but no major substation upgrades or expansions are required. The upgrades permit the interconnection of 71 MW of Group Study DER applicants, permits 345 MW of future DG enablement, and 0 MW of future electrification. This CIP is still pending approval in docket DPU 22-55. The proposed CIP fee for the group is $357/kW.

6.7.1.3 Project Solutions 2030 – 2034

The following project solutions are being developed for needs manifest within the ten-year planning horizon but will be in service between 2030 and 2034. Any project solution that will be in service by 2029, is included in the prior section (Project Solutions 2025 – 2029). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

- **Future Dennis-Brewster Substation** – Eversource is currently in the preliminary stages of developing a solution for the identified capacity needs in the Harwich to Orleans portion of the lower Cape (including the Towns of Harwich, Dennis, Brewster, Chatham, and Orleans). The solution may be a new 115/23kV bulk distribution substation and associated distribution upgrades in the 2034 time frame. Figure 171 below shows the potential location of the new station. The station will increase firm capacity supply in the area by 75 MW which will enable 73,000 new EVs or the equivalent of 15,000 residential heat pumps to be deployed in the service region.

---

[195] Table 2, page 41, DPU 22-54 Exhibit ES-Engineering Panel-1

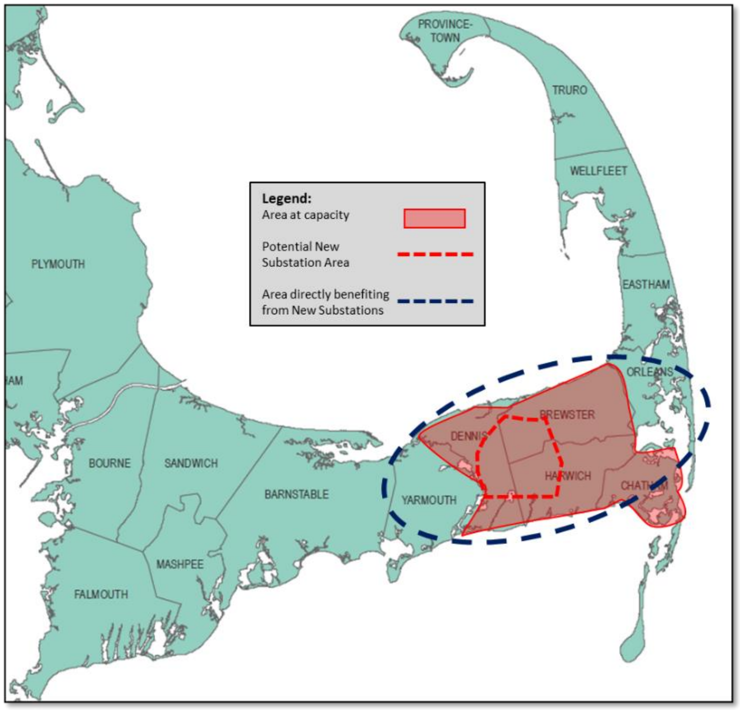


Figure 171: Future Dennis-Brewster Substation Potential Location

Solutions for DER Penetration Constraints

- East Freetown Group CIP (to replace New Bedford Group CIP which was not filed) – As described earlier, the existing Industrial Park Substation #636 cannot safely and reliably accommodate the amount of DER currently in the queue without significant substation expansion and distribution upgrades, which were discussed in the New Bedford Group Study. Under the proposed East Freetown CIP, a new substation is planned for the northern New Bedford, East Freetown, Dartmouth, Acushnet, and Rochester areas of Eastern Massachusetts which will help accommodate the DER growth and avoid the thermal overloads the in-queue DER would cause on the Industrial Park Substation. The new East Freetown Station will provide additional hosting capacity to the area, enable increased and timely adoption of proposed renewable energy and DERs, promote energy storage and electrification technologies, and improve grid reliability and resiliency. The approximate boundary of the CIP area and the locations of the Industrial Park substation and proposed new East Freetown substation are shown earlier in Figure 168.

  A total of 69 MW of existing and future DER are proposed to be transferred from the existing Industrial Park substation #636 to the new East Freetown substation #690. A preliminary analysis was performed to identify the required system upgrades to facilitate the safe and reliable interconnection of the DER. In addition, 12 MVA of existing distribution loads out of Industrial Park will be transferred to the new East Freetown substation.

A preliminary steady state analysis was conducted to identify the required system upgrades to support DER interconnection, load transfers and future DER, and to develop a preliminary CIP fee. While this analysis was informative for initial solution selection, a more detailed System Impact Study will be conducted for the East Freetown group to further refine the expected system upgrades and update the CIP fee for this area.

The approach to evaluating the preliminary solution involved a combination of engineering judgment, modeling, and simulation to iteratively determine appropriate design changes, technology and equipment application that would enable safe, reliable interconnection. During this process, solutions that were more costly were rejected in favor of solutions that could be counted on to reliably integrate as much DER as possible in a cost-effective manner. As part of the preliminary study solution, proposed system upgrades include installation of three new Standard 62.5 MVA substation transformers and associated switchgear for four feeder positions out of each substation bus. Distribution line upgrades are required to resolve thermal loading violations due to the transfer of distribution circuits 2-102-102 and 2-108-108 from Industrial Park to the new East Freetown substation. The new feeders and proposed upgrades allow the Group Study DER to connect and operate under both normal (N-0) and station contingency (N-1) conditions and create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme is proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns.

The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the East Freetown substation CIP. The capacity for the East Freetown CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 53 below. As a result of the substation upgrades identified in the Group Study, 119 MVA of Ground Mounted DERs could be reliably enabled – 80 MVA above and beyond the 39 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the Post Group Study 20 Year Ground Mounted DER Forecast (55 MVA), up to the substation enabled capacity (119 MVA). Eversource determined that in order to ensure that all DER up to 119 MVA who pay a proposed (preliminary) fixed CIP fee of $476/kW can safely and reliably connect to the Industrial Park and New East Freetown substations, eight new distribution feeders will be required for the future 80 MVA of DER beyond the group study. In addition, the solution enables 125 MVA of electrification, which is sufficient to meet the state's 2050 goals for the area. Figure 172 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 53: East Freetown Group Substation and Distribution Line Capacity Allocation

Substation

	Capacity Allocation of Distribution Substation between DER Customers and Load Customers					
Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Industrial Park 636	50	50	12	7	26	23
New East Freetown 690	125	63	113	2	94	58
	175	**113**	**125**	**10**	**119**	**80**

Distribution Line

	Capacity Allocation of Distribution Line between DER Customers and Load Customers					
Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Industrial Park 636	101	25	0	7	77	74
New East Freetown 690	198	49	186	2	166	130
	299	**75**	**186**	**10**	**244**	**205**

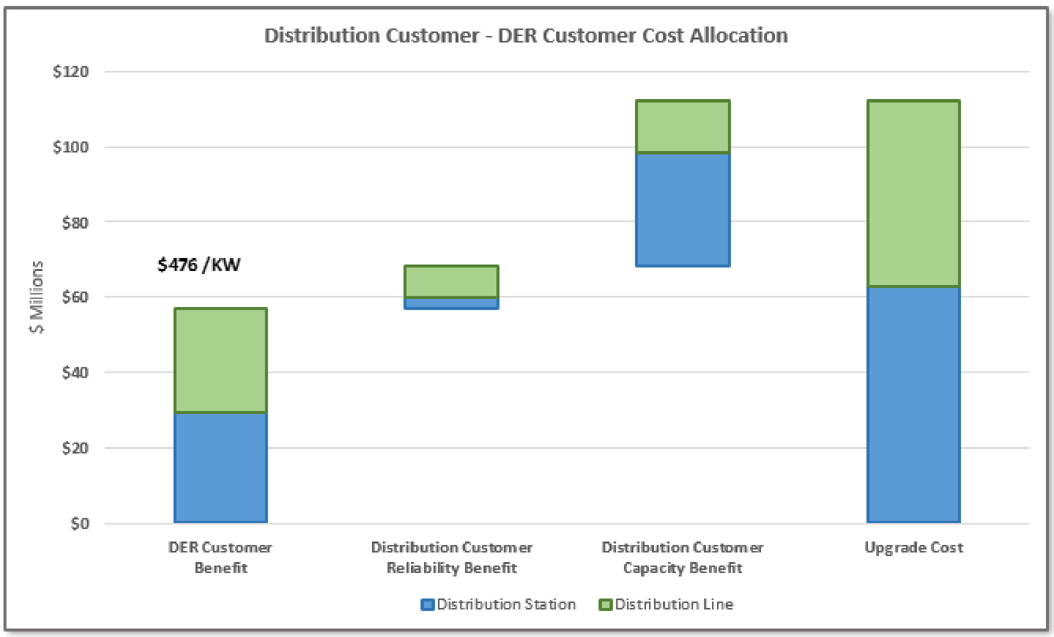


Figure 172: East Freetown CIP Cost Allocation

6.7.2. Non-Wire Alternatives

As part of its distribution planning process, the Company actively looks for opportunities to apply non-wires alternative (NWA) solutions to meet suitable[196] distribution needs in alignment with the Company's established NWA Framework.[197] Where technically feasible and economically viable, NWA solutions can be used to modify the load shape or resolve technical constraints, to defer distribution level upgrades.

In the EMA-South region, the Company has already deployed a battery-based microgrid solution to help meet reliability and resiliency needs in the Provincetown region of Cape Cod.

The Company is currently in preliminary stages of planning a combined BESS/STATCOM[198] to be installed at the Industrial Park Substation in New Bedford. The facility is needed to resolve long-standing power quality (PQ) issues affecting industrial customers within the New Bedford Business Park, and to support a higher penetration of DER at the substation. A 5MW/10 MWhr BESS coupled with a 25 MVAR STATCOM is proposed for mitigation of power quality (PQ) issues affecting industrial customers in the New Bedford Business Park that are served out of Industrial Park Substation. Two new 13.2kV bus sections and switchgear will be required to be installed at Industrial Park Substation as part of the BESS/STATCOM installation. The objective of the combined BESS/STATCOM installation at Industrial Park Substation is to improve the existing substation bus voltage response during voltage swings that result from steady-state and transient events at any appoint along the electric power system (EPS) supply. Because of the need for fast-acting technology in response to these types of disturbances, deploying utility-scale BESS and other inverter-based resources connected directly to Industrial Park Substation is proposed as a cost-effective and efficient solution for power quality problems, compared to a slower-acting transformer load-tap changer (LTC) or a step-type voltage regulator.

The project is currently going through the internal Eversource Capital Project Approval processes.

---

[196] An NWA solution is not considered to be suitable for resolving asset health issues or imminent issues such as a need appearing within less than 2 years

[197] Include link to public filing with NWA Framework

[198] A STATic synchronous COMpensator (STATCOM) is a fast-acting device capable of providing or absorbing reactive current and thereby regulating the voltage at the point of connection to a power grid.

6.7.3. Alternative Cost Allocation Approaches to Interconnect Solar Projects – Exploration of Different Approaches – pros and cons

As discussed in Section 6.1.4, under the Provisional Program order (20-75-B) the Company developed and applied a new cost allocation methodology based on a capacity allocation principle. This innovative cost structure allocates infrastructure upgrade costs between interconnecting DG customers and distribution customers in proportion to the load and capacity enabled for each during the DG group study, based on actual connected MVA capacity. In 2022, the Company submitted six CIP proposals with the innovate cost allocation methodology for six groups, including five in EMA-South: Marion-Fairhaven (D.P.U 22-47), Freetown (DPU 22-51), Plymouth (DPU 22-54), Dartmouth-Westport (DPU 22-53) and Cape (DPU 22-55). The Marion-Fairhaven CIP has been approved for construction and the four other CIP proposals in EMA-South (as well as the one in WMA) are still pending approval with the Department. Summary descriptions of the EMA-South CIPs are included in Section 6.7.1.2.

In addition, as described in Section 6.7.1.3, the cost allocation methodology is being applied to the new East Freetown station CIP, which is currently under development.

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

A number of the projects studied under the Provisional Program included solar coupled with storage, but there were no standalone battery projects. At this time, there are standalone battery projects queued at substations in EMA-South. It is possible that the enabled capacity in the approved (Marion-Fairhaven) CIP, the other four CIPs which are pending approval in EMA-South or the newly proposed East Freetown CIP could be used by standalone battery projects, with similar CIP provisions as solar projects.

6.7.5. Equity and EJ outreach

The Company's EJ and equity outreach framework will be applicable to the Southern Subregion and the overall framework is discussed in detail in Section 3.

6.8. WMA Sub-Region

The Eversource Western Massachusetts (WMA) Sub-region consists of all or parts of sixty (60) Towns and Cities in Central and Western Massachusetts served out of the Company's Pittsfield, Springfield, and Hadley Area Work Centers (AWC's). The region consists of the Cities of Springfield and Pittsfield and surrounding Towns in Berkshire, Hampshire, Hampden, and Franklin Counties. Some Towns served are jointly served with National Grid (Hancock, Cheshire, and Erving) or Municipal Electric Departments (Russell). There are 223,396 Eversource customer accounts covering high, moderate, and low load density areas. Parts of the Eversource Springfield AWC has industrial and heavy commercial load within the City of Springfield.

The detailed overview of forecasted demand for in Section 5 shows that over the next decade, the electric demand for the summer peak in the WMA Sub-Region is expected to go from 892 MVA in 2023 to 932 MVA in 2033, an increase of 4% over the planning horizon driven predominantly by EV growth.

To meet its obligation to provide reliable service to all customers, the Company has assessed the impact of 90/10 weather-normalized forecasted demand on each of its bulk distribution substations. This assessment is conducted on a yearly basis to evaluate impact of underlying load growth, as well as several adders that impact the peak demand and substation capacity constraints, including electrification trends. The following section details the system needs and major projects planned, proposed or envisioned to safely and reliably meet those needs on a localized basis.

6.8.1. Major Substation Projects

6.8.1.1 Capacity and Reliability Needs

Through its annual capacity planning processes[199] and reported in the ARR under DPU docket 23-ARR-02[200] and as reported in the Company's Rate Case Filing under DPU 22-22, the Company identified municipalities that are currently supplied by an electric power system (EPS) with existing or projected capacity and/or reliability deficiencies. More specifically, the Company identified in its Long-Range Plan (LRP) communities supplied by bulk distribution substations projected to be at capacity now or expected to be at capacity in the next ten-years.

Table 54 below presents a community-centric view of capacity deficiencies. The table lists the communities WMA and the existing or projected substation or distribution line supply deficiency by type (Reliability and/or Capacity) and timeframe for the need (substation at capacity now, at capacity within 5 years, at capacity within 10 years, at capacity beyond 10-year planning horizon). For consistency with the information provided earlier in Section 4.6.7, the table also lists the communities that have both existing and on-going supply deficiencies.

Table 54: WMA Communities and Projected EPS Deficiencies

Municipality	Type	County	Deficiency	Timeframe for Need
Ashfield	Town	Franklin	Capacity	Now/Existing
Chesterfield	Town	Hampshire	Capacity	Now/Existing

[199] Refer to Section 4.3.7 for details on the capacity planning process
[200] See Footnote 147 in Section 6.5.1

Municipality	Type	County	Deficiency	Timeframe for Need
Cummington	Town	Hampshire	Capacity	Now/Existing
Longmeadow	Town	Hampden	Capacity	Now/Existing
Middlefield	Town	Hampshire	Capacity	Now/Existing
Plainfield	Town	Hampshire	Capacity	Now/Existing
Springfield	City	Hampden	Capacity	Now/Existing
Windsor	Town	Berkshire	Capacity	Now/Existing
Worthington	Town	Hampshire	Capacity	Now/Existing
Ludlow	Town	Hampden	Reliability	Now/Existing
Dalton	Town	Berkshire	Reliability	Now/Existing
Lanesborough	Town	Berkshire	Reliability	Now/Existing
New Ashford	Town	Berkshire	Reliability	Now/Existing
Agawam	City	Hampden	Capacity	Within 5 years

Table 55 below presents a substation-centric view of capacity deficiencies. The table shows the substation name or location in the first column, followed by the community that is supplied by the substation. The table also shows how constrained the substation is projected to be compared to its substation thermal capacity. This number is shown as a percentage and is computed as substation projected peak load divided by the substation capacity. A value greater than 100% is a violation of the company planning criteria since the transformers' expected peak load will exceed the substation capacity. The last column on the table shows the associated 2025-2029 or 2030-2034 project solutions, later described in Sections 6.7.1.2 and 6.7.1.3, to address the projected overload.

Table 55: WMA Substations with Projected Capacity Deficiencies and Communities Impacted

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.8.1.2 and 6.8.1.3)
Plainfield	Ashfield, Chesterfield, Cummington, Middlefield, Plainfield, Windsor, and Worthington	**135%**	Plainfield Substation Upgrade
Clinton	Springfield	**106%**	Clinton 21S Substation Upgrade
Partridge[201]	Dalton, Lanesborough, and New Ashford	**100%**	Partridge Substation Upgrade
Ludlow[202]	Ludlow	**100%**	Ludlow Substation Upgrade
Franconia	Springfield and Longmeadow	**93%**	Franconia Substation Upgrade
Silver[203]	Agawam	**83%**	Silver Substation Upgrade

Currently 5 of 28 substations supplying the WMA area have a capacity and/or reliability violation, and during the ten-year planning horizon one additional substation, for a total of 6 of 28 substations, is projected to have capacity and/or reliability violations. The substations supplying the WMA area are of special concern because of the long distance of the existing distribution feeders which decreases reliability for all customers supplied by the substation. Moreover, due to the amount of time that it will take to site and permit a new substation in this area, a solution could take more time to implement than in any other area of Massachusetts.

Through its annual capacity planning processes, as noted in the ARR, the company goal is to have a solution for any substation expected to exceed 90% of its capacity during the ten-year planning horizon. However, despite the Company's best laid plans to develop and implement solutions for forecasted needs, there are times when the project implementation might miss the need date, due to several factors, primarily siting and permitting delays. When this occurs, the Company has an obligation to develop interim or emergency *operational* measures to ensure that customers are not unserved during an outage. These measures could include anything from load transfers to other substations via distribution ties, to temporary spot generation deployment, to development of non-wires alternatives such as battery storage where feasible. However, these options are only temporary measures and will be exhausted and

[201] 100% Substation Capacity reflects substation reliability violation not capacity violation
[202] 100% Substation Capacity reflects substation reliability violation not capacity violation
[203] Percent of Substation capacity does not account for large changes in new business growth expected in the area, which could decrease the available operational capacity starting beyond 90%.

ineffective as load continues to grow. A permanent planning solution must be implemented at some point to ensure long-term reliable service.

Capacity Deficiencies due to DER Penetration[204]

DPU 22-52 (Plainfield-Blandford Group Study)[205] – The Plainfield-Blandford Group comprises of one substation in Western Massachusetts (WMA): Blandford 19J. The substation serves 11 MVA of customer peak load. There is a total of 37 MW of installed ground mounted (large) DER, in addition to less than 1 MW rooftop (small) DER, and the Group Study will interconnect another 13 MW of large DER, bringing the total DER penetration to 454% of peak load for the group. Figure 173 below shows the approximate geographical location, in the WMA service area, served by the substation. A CIP was developed for this group and filed in docket D.P.U. 22-52. The solution is described in the following section.

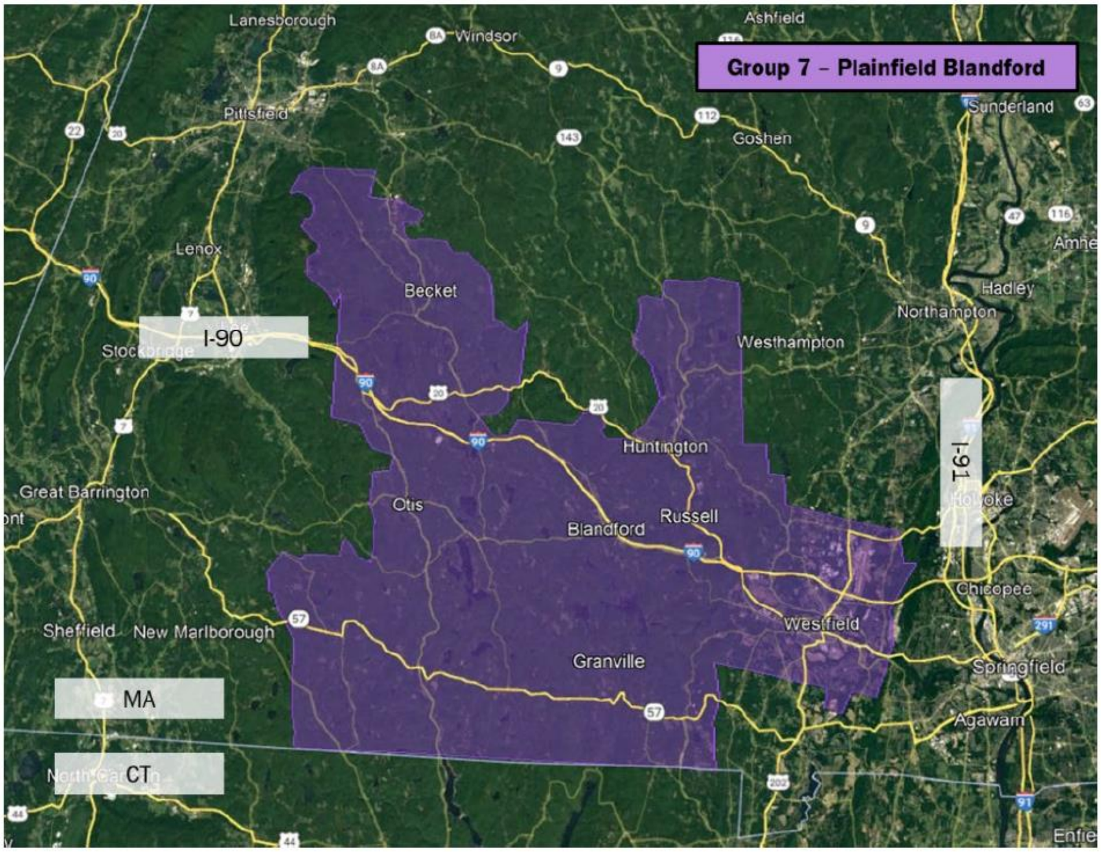


Figure 173: Plainfield-Blandford DER Group Approximate Boundary

[204] Refer to Provisional System Planning Program Guide | Mass.gov
[205] Refer to DPU 22 Exhibit ES-Engineering Panel-1; Approved by the Department December 2022

Whately-Deerfield DER Group - The Whately-Deerfield Group comprises of five existing substations, (Podick 18G, French King 21B, Montague 21C, Cumberland 22B, and Shelburne 29R), and one proposed substation, (Whately-Deerfield 23P), in WMA. The ten-year forecasted peak load for all the substations is 130 MVA and there is a total of 96 MW of installed ground mounted (large) DER, in addition to 31 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 86 MW of large DER, bringing the total DER penetration to 163% of peak load for the group. Based on the of 34 GW potential of technically developable land in the area, the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. Figure 174 below shows the approximate geographical location of the substation and the geographic location served by the substation in the WMA Service Area. The proposed CIP solution is described in Section 6.8.1.3.

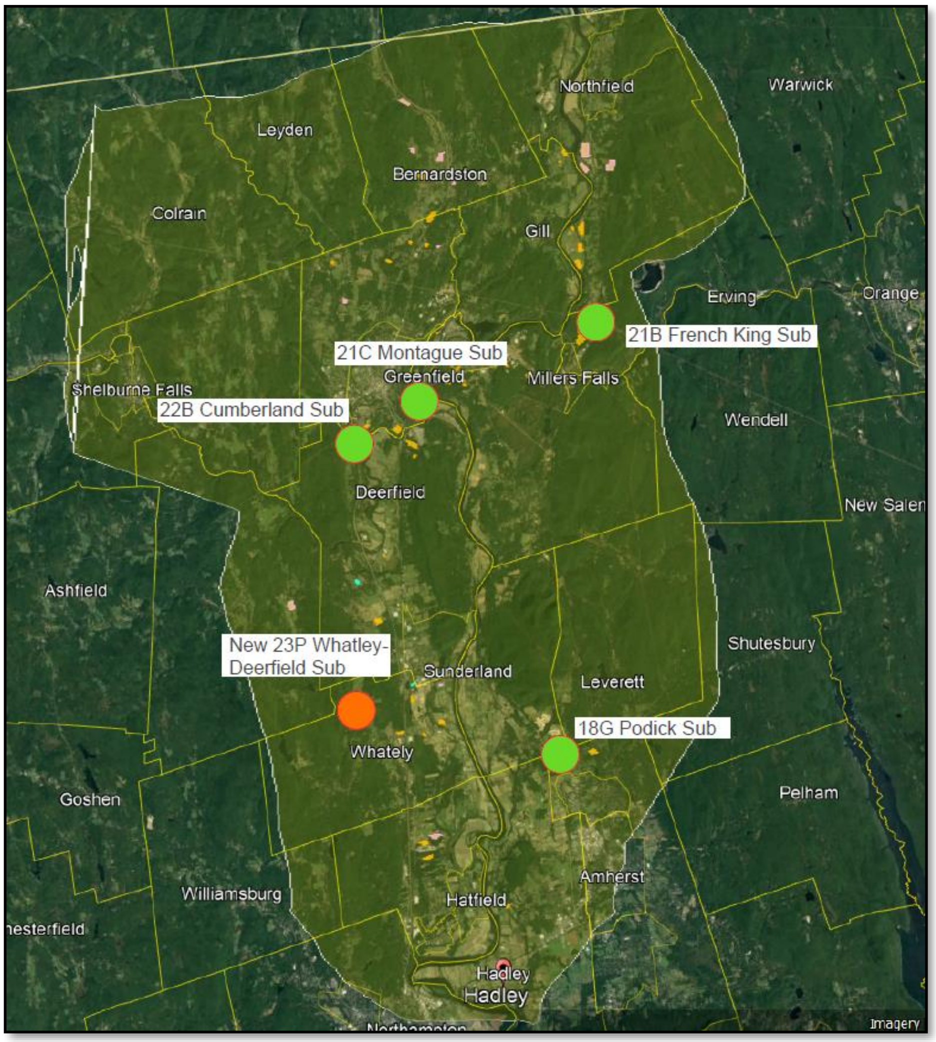


Figure 174: Whately-Deerfield Group Study Area

Southwick-Granville DER Group - The Southwick-Granville Group comprises of one existing substation, Southwick 29A, in WMA. The ten-year forecasted peak load for the substation is 33

MVA and there is a total of 41 MW of installed ground mounted (large) DER, in addition to 3 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 19 MW of large DER, bringing the total DER penetration to 190% of peak load for the group. Based on the of 7 GW potential of technically developable land in the area, the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. Figure 175 below shows the approximate geographical location of the substation and the geographic location served by the substation in the WMA Service Area. The proposed CIP solution is described in Section 6.8.1.3.

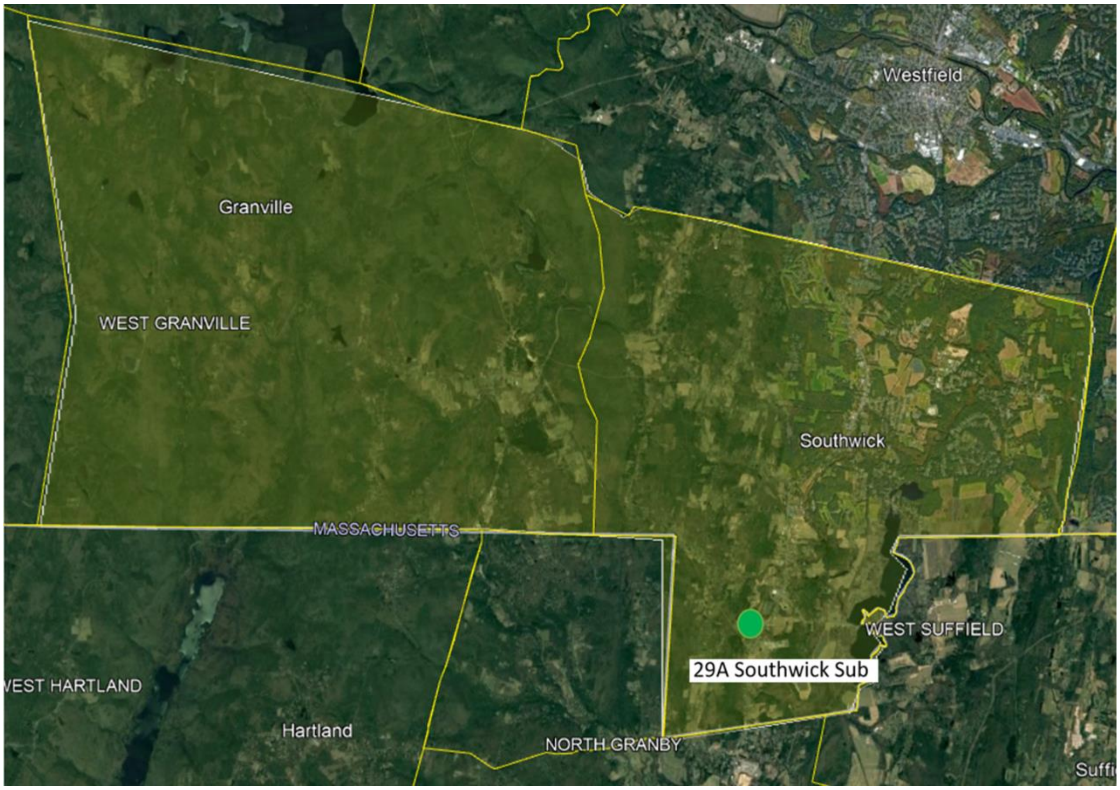


Figure 175: Southwick-Granville Group Study Area

Dalton-Hinsdale DER Group - The Dalton-Hinsdale Group comprises of one existing substation, Berkshire 18C, in WMA. The ten-year forecasted peak load for the substation is 9 MVA and there is a total of 21 MW of installed ground mounted (large) DER, in addition to 4 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 21 MW of large DER, bringing the total DER penetration to 511% of peak load for the group. Based on the of 13 GW potential of technically developable land in the area, the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. Figure 176 below shows the approximate geographical location of the substation and the geographic location served by the substation in the WMA Service Area. The proposed CIP solution is described in Section 6.8.1.3.

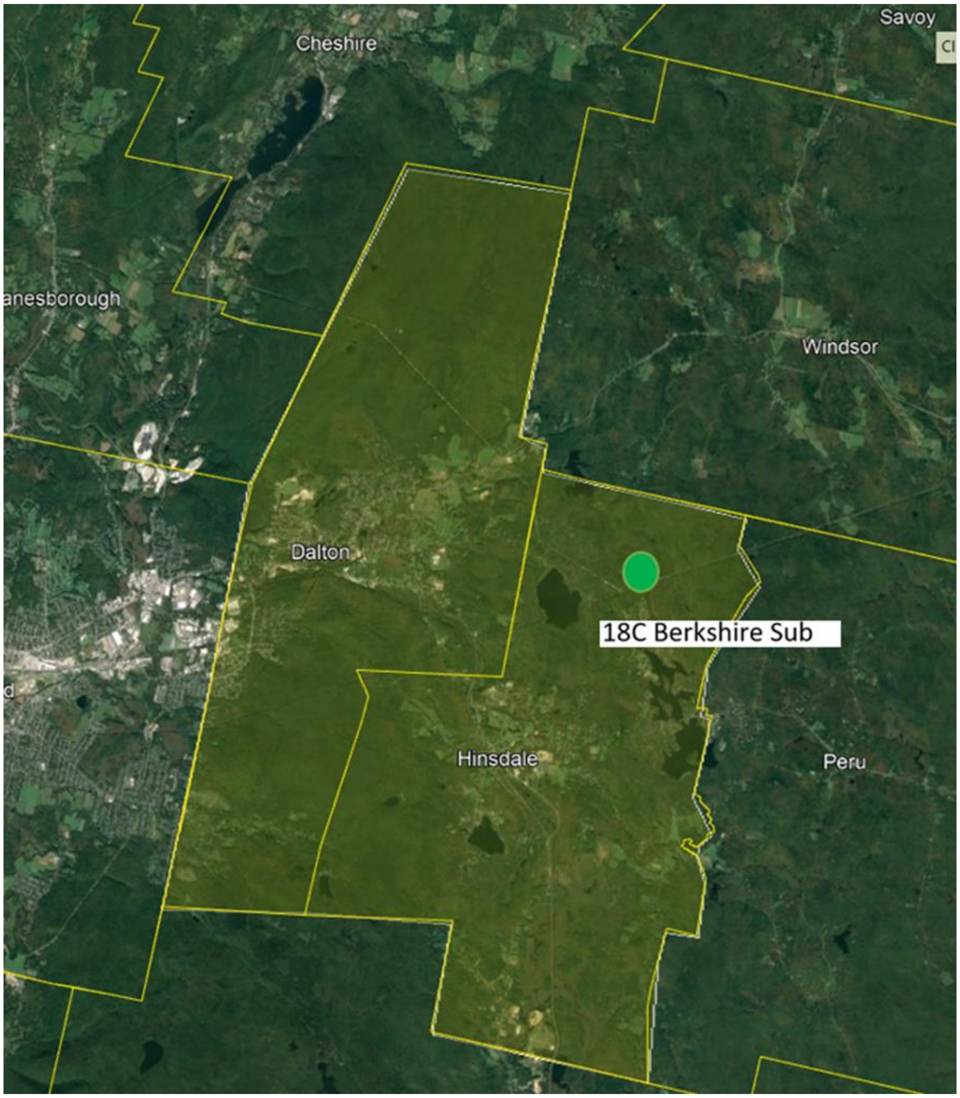


Figure 176: Dalton-Hinsdale Group Study Area

A**gawam-Feeding Hills DER Group** - The Agawam-Feeding Hills Group comprises of one existing substation, Silver 30A in WMA. The ten-year forecasted peak load for the substation is 46 MVA and there is a total of 13 MW of installed ground mounted (large) DER, in addition to 5 MW of rooftop (small) DER on the substation. The Group Study will interconnect another 7 MW of large DER, bringing the total DER penetration to 54% of peak load for the group. Based on the of 653 MW potential of technically developable land in the area, the proposed Group can be expected to fully subscribe over the 20-year recovery horizon. Figure 177 below shows the approximate geographical location of the substation and the geographic location served by the substation in the WMA Service Area. The proposed CIP solution is described in Section 6.8.1.3.

Figure 177: Agawam-Feeding Hills Group Study Area

6.8.1.2 Project Solutions 2025 - 2029

Through its annual capacity planning processes as reported in the Annual Reliability Report under DPU docket 23-ARR-02[206] and as reported in the Company's Rate Case Filing under DPU 22-22[207], the following projects have been either proposed or approved for mitigation of capacity or reliability deficiencies on the WMA EPS (electric power system) as discussed above.

All project solutions in this section are expected to be in service by 2029. Any project solution that will be in service after 2029, even if capital expenditure occurs before 2029, are included in the next section (Project Solutions 2030 - 2034). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

---

[206] See Footnote 41 in Section 4.3.7
[207] See Footnote 42 in Section 4.3.7

Capacity Deficiencies due to load growth and reliability

- **Clinton substation upgrade –** As noted in Section 4.6.7, the Company has internally approved, on-going, projects to replace one transformer and switchgears in the next 5 years. Clinton Substation is a three 115/13.8 kV transformers substation serving the City of Springfield with several critical customers such as three hospitals and other large commercial centers. Large customer load additions in the area requires station upgrades to increase the station capacity and improve the service reliability. Project is expected to be completed by 2024.

- **Franconia #22H Substation Upgrade** – Franconia Substation is a two 115/13.8 kV transformers substation serving the city of Springfield and town of Longmeadow. The Company has an internally approved project to replace the existing 47 MVA Transformer with a standard size 37.5/50/62.5MVA transformer by 2024. The transformer upgrade will address long-term capacity and reliability concerns in the area.

- **Plainfield Transformer Upgrade** – As noted in Section 4.6.7, the Company has an internally approved project to replace the existing 5 MVA transformers with a standard size 37/50/62.5 MVA transformers with an expected in-service date of 2026. The transformer upgrade will address long-term capacity and reliability concerns in Plainfield Substation and nearby areas.

- **Silver #30A Substation Upgrade** – This is a 2-transformer 115/14 kV substation serving the Town of Agawam. Due to potential load growth exceeding 89% firm capacity of the station, both existing transformers will be replaced with new 37/50/62.5 MVA transformers, one per year starting in 2024 with an expected in-service date of 2026.

- **Ludlow Substation Upgrade** - The company is in the planning stages for a proposed solution to address reliability concerns Ludlow Substation. Ludlow is one of several WMA Substations running as a single transformer design which would rely on distribution feeder/line transfer switching capacity during a single contingency condition. Current operational measures rely on mobile equipment to restore customers following a single contingency event. However, there will be risk of residual load loss (customers that are not restored) due to capacity limitations of the distribution feeder/line system. To resolve reliability concerns with residual load loss, a project is in the planning phase that will resolve reliability violations at Ludlow substation. Solutions to this reliability violations could include adding a new transformer at the substation, or additional distribution line right-of-way to improve the distribution transfer capability. This project is expected to be in-service by 2026.

- Partridge Substation Upgrade - The company is in the planning stages for a proposed solution to address reliability concerns Partridge Substation. Partridge is one of several WMA Substations running as a single transformer design which would rely on distribution feeder/line transfer switching capacity during a single contingency condition. Current operational measures rely on mobile equipment to restore customers following a single contingency event. However, there will be risk of residual load loss (customers that are not restored) due to capacity limitations of the distribution feeder/line system. To resolve reliability concerns with residual load loss, a project is in the planning phase that will resolve reliability violations at Partridge substation. Solutions to this reliability violations could include adding a new transformer at the substation, or additional distribution lines right-of-way to improve the distribution transfer capability. This project is expected to be in-service by 2026.

Solutions for DER Penetration Constraints[208]

- **DPU 22-52 (Blandford-Plainfield)** – One substation (Blandford #19J) serving all or part of the Towns of Blandford, Russell, Sandisfield, Otis, Huntington, Middlefield, Chester, Montgomery, Granville, Westfield, Becket, and Tolland. The substation will be rebuilt with two 37/50/62.5 MVA 115/23kV transformers, new metalclad switchgear, and there will be upgrades to existing 23kV feeders to permit the interconnection of Group Study applicants. The upgrades permit the interconnection of 13 MW of Group Study DER applicants, permits 41 MW of future DG enablement, and 48 MW of future electrification. A decision on the CIP is still pending approval with the Department. The proposed CIP fee for the group is $498/kW.

6.8.1.3 Project Solutions 2030 - 2034

The following project solutions are being developed for needs manifest within the ten-year planning horizon but will be in service between 2030 and 2034. Any project solution that will be in service by 2029, are included in the prior section (Project Solutions 2025 - 2029). This aligns with the Company's Long-Range Plan (LRP) which covers the five-year investment period 2025 to 2029.

- **Future Hilltown Substation** – This project is currently in the planning phase and is proposing to establish a new 115/23 kV substation in Worthington and surrounding area to sever the potential load growth, improve reliability, and enable more hosting capacity for DER interconnections. The load in the Chester-Worthington area of WMA is currently supplied by Plainfield 18K and Blandford 19J substations. Due to the long physical distance between the two substations, limited number of roads, and limited number of distribution rights-of-way, some of the feeders supplying the area of

[208] D.P.U 22-47 was approved by the Department on December 2022, the remaining projects (D.P.U 22-51 to D.P.U 22-55) are pending a decision from the Department; Refer to Provisional System Planning Program Guide | Mass.gov for additional information

Chester/Worthington are close to 200 miles in length. This leaves customers expose to more frequent outages occurring over a very long path. A comprehensive solution that involves transmission and substation infrastructure is being proposed to reduce feeder size and increase the distribution system reliability.

Solutions for DER Penetration Constraints

- **Whately-Deerfield Group CIP** – A new Substation is planned for the Whately, Deerfield, Hatfield area of Western Massachusetts. This general area is currently served by five Substations; Cumberland #22B, Montague 21C, Podick 18G, French King 21B and Shelburne 29R which are interdependent and rely on each other during emergencies as well as day-to-day system operations. Due to station capacity deficiencies, distribution line reliability constraints, DER penetration, increasing load growth associated with agricultural and commercial sectors, and limited river crossings from the existing Podick substation a holistic plan to build a new 115/13.8kV Station is proposed as part of the CIP. The new station will relieve the existing French King, Cumberland, Podick, Montague and Shelburne substations and enable future DER interconnections and electrification demand in the area.

  A high-level analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER in the area. The initial assessment determined that several upgrades would be needed to enable approximately 189 MVA of DER beyond the 86 MW in the Group Study. These include: upgrading the existing 30 MVA transformer at French King to 62.5 MVA, upgrading the switchgear, and adding a second 62.5 MVA bank with associated switchgear; upgrading an existing 47 MVA transformer at Cumberland to 62.5 MVA and upgrading the switchgear; and constructing a new greenfield substation with two 62.5 MVA transformers and associated switchgear. The transformer and switchgear upgrades and additions will also enable future DER interconnections and help address any potential electrification and load growth needs in the area. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee.

  Due to the amount of in-queue ground mounted DERs, thermal overload significantly above distribution equipment ratings is observed. For these violations, the most common solution is to upgrade the existing equipment or to add new substation equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns.

The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Whately-Deerfield CIP. The capacity for the Whately-Deerfield CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 56 below. As a result of the substation upgrades identified in the Group Study, 189 MVA of Ground Mounted DERs could be reliably enabled – 103 MVA above and beyond the 86 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 189 MVA who pay a proposed (preliminary) fixed CIP fee of $513/kW can safely and reliably connect to the Whately-Deerfield CIP substations, four new feeders are needed for the 86 MVA of Group Study DER and an additional twenty-one (21) new feeders will be required for the future 103 MVA of DER beyond the Group Study. In addition, the solution enables 54 MVA of electrification, which is sufficient to meet about 50% of the state's 2050 goals for the area. Figure 178 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 56: Whately-Hatfield CIP Substation and Distribution Line Capacity Allocation

Substation	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)	Substation
	18G-PODICK	50	47	0	5	31	6	
	21B-FRENCH KING	63	63	46	3	39	32	
	21C-MONTAGUE	63	63	0	5	36	7	
	22B-CUMBERLAND	63	63	0	9	45	27	
	23P-New Whately-Deerfield	63	63	8	7	35	26	
	29R Shelburne	6	0	0	2	4	4	
		306	**297**	**54**	**31**	**189**	**103**	

Distribution Line	Stations	Capacity Allocation of Distribution Line between DER Customers and Load Customers						Distribution Line
	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)	
	18G-PODICK	88	22	0	5	69	44	
	21B-FRENCH KING	93	23	65	3	70	63	
	21C-MONTAGUE	92	23	0	5	65	37	
	22B-CUMBERLAND	115	34	55	9	97	80	
	23P-New Whately-Deerfield	188	47	133	7	161	152	
	29R Shelburne	14	0	1	2	12	12	
		591	**149**	**254**	**31**	**474**	**388**	

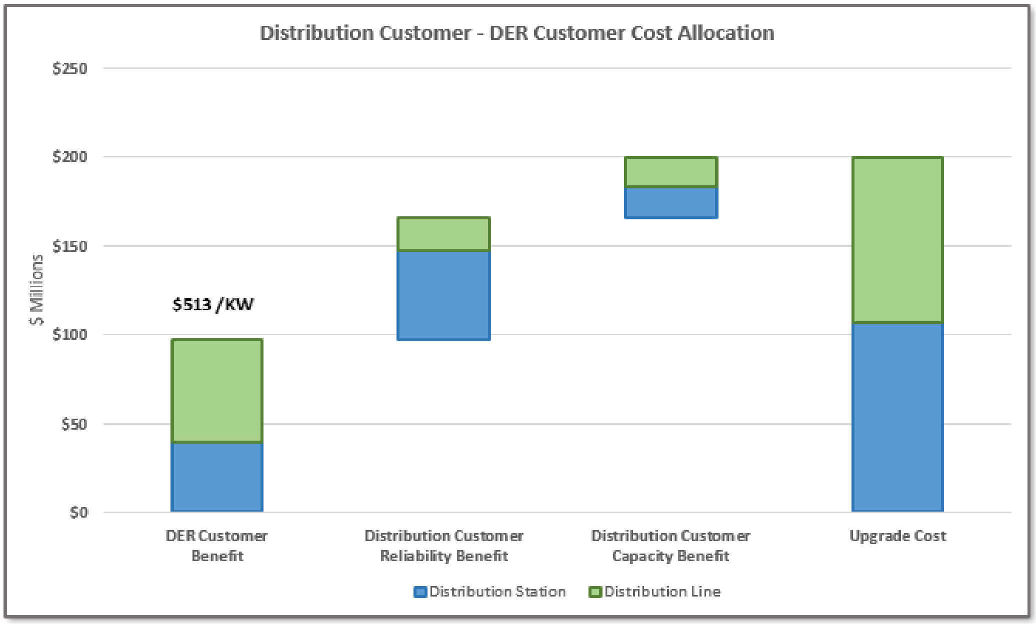


Figure 178: Whately-Deerfield Cost Allocation and CIP Fee

- **Southwick-Granville Group CIP -** A preliminary analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER. The initial assessment shows that upgrading the two existing transformers to 62.5 MVA and adding a third new 62.5 MVA transformer and associated switchgear will enable approximately 88 MVA of DER beyond the 19 MW in the Group Study. The transformer and switchgear upgrades will also enable future DER interconnections and help address any potential electrification and load growth needs in the area. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee. Due to the amount of in-queue ground mounted DERs, thermal overload significantly above distribution equipment ratings is observed. For these violations, the most common solution is to upgrade the existing equipment or to add new substation equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns. The Southwick substation is currently double-ended and the transformers and switchgear will be upgraded to allow up to five feeders out of each substation bus. The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Southwick-Granville CIP. The capacity for the Southwick-Granville CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 57 below. As a result of the substation upgrades identified in the Group Study, 88 MVA of Ground Mounted DERs could be reliably enabled – 69 MVA above and beyond the 19 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 88 MVA who pay a proposed (preliminary) fixed CIP fee of $488/kW can safely and reliably connect to the Southwick-Granville CIP substation, two new feeders are needed for the 19 MVA of Group Study DER and an additional nine new feeders will be required for the future 69 MVA of DER beyond the Group Study. In addition, the solution enables 78 MVA of electrification, which is sufficient to meet the state's 2050 goals for the area. Figure 179 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 57: Southwick-Granville CIP Substation and Distribution Line Capacity Allocation

		Capacity Allocation of Distribution Substation between DER Customers and Load Customers						
Substation	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)	Substation
	Southwick 29A	125	63	78	3	88	69	
		125	**63**	**78**	**3**	**88**	**69**	

		Capacity Allocation of Distribution Line between DER Customers and Load Customers						
Distribution Line	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)	Distribution Line
	Southwick 29A	205	51	158	3	168	149	
		205	**51**	**158**	**3**	**168**	**149**	

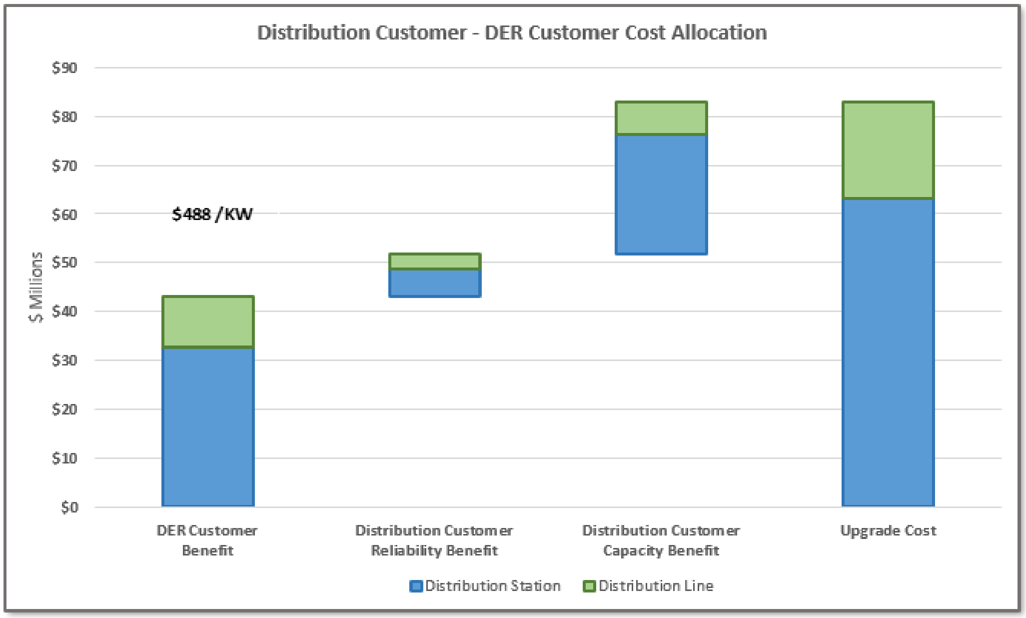


Figure 179: Southwick-Glanville Cost Allocation and CIP fee

- **Dalton-Hinsdale Group CIP -** The Company is currently developing a Group Study solution for the 21 MW of DG applications in the Dalton-Hinsdale area of the WMA region. A preliminary analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER. The initial assessment shows that upgrading the existing transformer to 62.5 MVA and adding three new 62.5 MVA transformers will enable approximately 99 MVA of DER beyond the 21 MW in the Group Study. The transformer and switchgear upgrades will also enable the future DER interconnections and help address any potential electrification and load growth needs in the area. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee. Due to the amount of in-queue ground mounted DERs, thermal overload significantly above distribution equipment ratings is observed. For these violations, the most common solution is to upgrade the existing equipment or to add new substation equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns.

The Berkshire substation is currently single-ended and the transformers and switchgear will be upgraded to allow up to five feeders out of each substation bus. The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Dalton-Hinsdale CIP. The capacity for the Dalton-Hinsdale CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 58 below. As a result of the substation upgrades identified in the Group Study, 99 MVA of Ground Mounted DERs could be reliably enabled – 78 MVA above and beyond the 21 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 99 MVA who pay a proposed (preliminary) fixed CIP fee of $432/kW can safely and reliably connect to the Dalton-Hinsdale CIP substation, three new feeders are needed for the 21 MVA of Group Study DER and an additional ten new feeders will be required for the future 78 MVA of DER beyond the Group Study. In addition, the solution enables 116 MVA of electrification, which is sufficient to meet the state's 2050 goals for the area. Figure 180 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 58: Dalton-Hinsdale Substation and Distribution Line Capacity Allocation

Substation		Capacity Allocation of Distribution Substation between DER Customers and Load Customers						Substation
	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)	
	Berkshire 18C	125	63	116	4	99	78	
		125	**63**	**116**	**4**	**99**	**78**	

Distribution Line		Capacity Allocation of Distribution Line between DER Customers and Load Customers						Distribution Line
	Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity-Post Group Study (MVA)	
	Berkshire 18C	252	63	214	4	226	205	
		252	**63**	**214**	**4**	**226**	**205**	

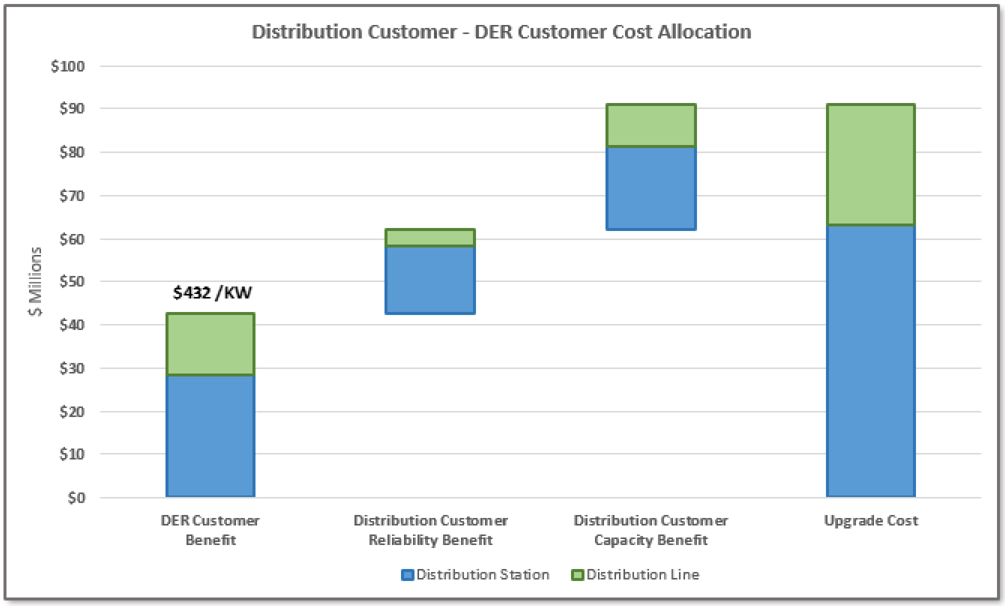


Figure 180: Dalton-Hinsdale Cost Allocation and CIP Fee

- **Agawam-Feeding Hills Group CIP -** The Company is currently developing a Group Study solution for the 7 MW of DG applications in the Agawam-Feeding Hills area of its Western MA area territory. A preliminary analysis was conducted to identify the required system upgrades due to substation capacity deficiencies and distribution line reliability constraints to facilitate the safe and reliable interconnection of the Group Study DER. The initial assessment shows that upgrading one of the two existing transformers from 46.7 MVA to 62.5 MVA will enable approximately 54 MVA of DER beyond the 7 MW in the Group Study. The transformer upgrade will also enable future DER interconnections and help address any potential electrification and load growth needs in the area. A more formal Group Study in this area will be conducted to further refine the expected system upgrades and update the potential CIP fee. Due to the amount of in-queue ground mounted DERs, thermal overload significantly above distribution equipment ratings is observed. For these violations, the most common solution is to upgrade the existing equipment or to add new substation equipment or feeders to resolve the violation. The new facilities and upgrades allow the Group Study DER to interconnect and operate under both normal (N-0) and emergency (N-1) conditions and also create additional headroom for future DER due to the use of standard equipment sizes. For voltage regulation issues, implementation of a Volt-VAR Optimization (VVO) scheme may be proposed to mitigate voltage quality concerns. According to the preliminary study results, series reactor(s) may be required to reduce overall system short-circuit current values. For PV + Battery Energy Storage Systems (BESS) applications, ramp rate limitation will be considered to address flicker concerns. The Silver substation is currently double-ended and the transformer and switchgear will be upgraded to allow up to six feeders out of each substation bus. The updated cost allocation methodology described earlier in Section 6.1.4 incorporating the ten-year forecasted load was applied to the Agawam-Feeding Hills CIP. The capacity for the Agawam-Feeding Hills CIP is allocated across both the substation level and the distribution feeder level, as shown in Table 59 below. As a result of the substation upgrades identified in the Group Study, 54 MVA of Ground Mounted DERs could be reliably enabled – 47 MVA above and beyond the 7 MVA in the Group Study. However, despite the available substation capacity, additional distribution feeder upgrades are also necessary to accommodate this amount of enabled DER. Specifically, additional distribution feeders would be required to interconnect the 20-Year Ground Mounted DER Forecast up to the substation enabled capacity. Eversource determined that in order to ensure that all DER up to 54 MVA who pay a proposed (preliminary) fixed CIP fee of $162/kW can safely and reliably connect to the Agawam-Feeding CIP substation, one new feeder is needed for the 7 MVA of Group Study DER and an additional five new feeders will be required for the future 47 MVA of DER beyond the Group Study. Figure 181 shows the breakdown in CIP costs between DER and distribution customers and the resulting preliminary CIP fee.

Table 59: Agawam-Feeding Hills Substation and Distribution Line Capacity Allocation

Substation

	Capacity Allocation of Distribution Substation between DER Customers and Load Customers					
Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Silver 30A	63	63	0	5	54	47
	63	**63**	**0**	**5**	**54**	**47**

Distribution Line

	Capacity Allocation of Distribution Line between DER Customers and Load Customers					
Stations	Reserved DER Capacity (MVA)	Reserved Operational Capacity (MVA)	Enabled Electrification (MVA)	Enabled Rooftop DER Capacity (MVA)	Enabled Ground Mounted DER Capacity - Group Study (MVA)	Enabled Ground Mounted DER Capacity- Post Group Study (MVA)
Silver 30A	158	40	92	5	149	142
	158	**40**	**92**	**5**	**149**	**142**

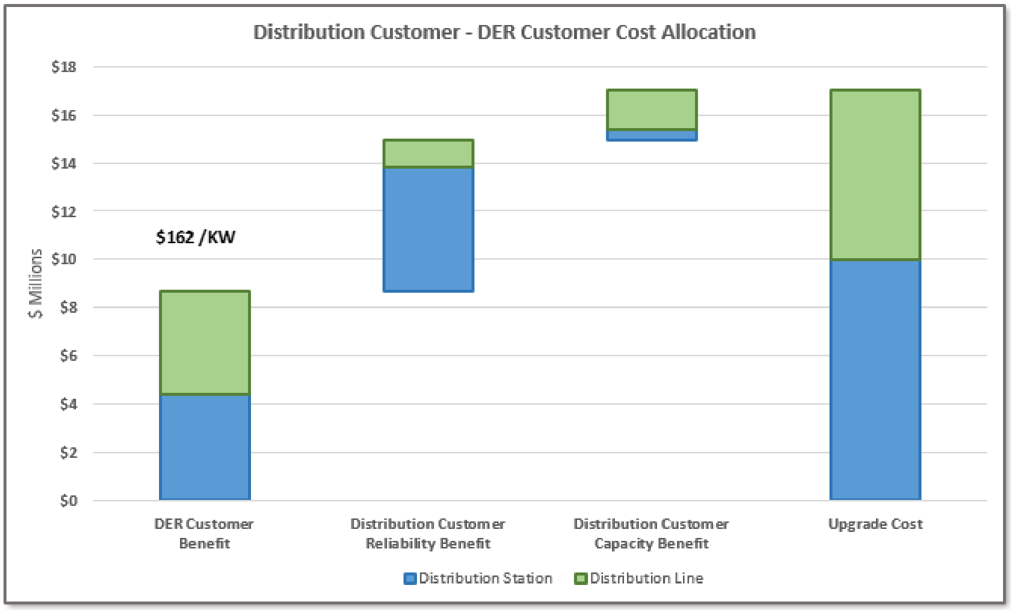


Figure 181: Agawam-Feeding Hills Cost Allocation and CIP Fee

6.8.2. Non-Wire Alternatives

As part of its distribution planning process, the Company actively looks for opportunities to apply non-wires alternative (NWA) solutions to meet suitable[209] distribution needs in alignment with the Company's established NWA Framework.[210] Where technically feasible and economically viable, NWA solutions can be used to modify the load shape or resolve technical constraints, to defer distribution level upgrades.

Currently, the Company does not have an NWA solution planned for the WMA region. The Company is continually evaluating project needs and will continue to assess the viability of NWA solutions for suitable needs.

6.8.3. Alternative cost allocation approaches to interconnect solar projects – exploration of different approaches – pros and cons

As discussed in Section 6.1.4, under the Provisional Program order (20-75-B) the Company developed and applied a new cost allocation methodology based on a capacity allocation principle. This innovative cost structure allocates infrastructure upgrade costs between

[209] An NWA solution is not considered to be suitable for resolving asset health issues or imminent issues such as a need appearing within less than 2 years.
[210] Include link to public filing with NWA Framework

interconnecting DG customers and distribution customers in proportion to the load and capacity enabled for each during the DG group study, based on actual connected MVA capacity. In 2022, the Company submitted six CIP proposals with the innovate cost allocation methodology for six groups, including one) in WMA: Plainfield-Blandford (D.P.U 22-52). The Marion-Fairhaven CIP has been approved for construction and the five other CIP proposals, including Plainfield-Blandford in WMA, are still pending approval with the Department. A summary description of the WMA CIP is included in Section 6.8.1.2.

In addition, as described in Section 6.8.1.3, the cost allocation methodology is being applied to four proposed CIPs currently under development in WMA: Whately-Deerfield, Southwick-Granville, Dalton-Hinsdale and Agawam-Feeding Hills.

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

A number of the projects studied under the Provisional Program included solar coupled with storage, but there were no standalone battery projects. At this time, there are standalone battery projects queued at substations in the WMA region, and it is quite possible the proposed Whately-Deerfield, Southwick-Granville, Dalton-Hinsdale and Agawam-Feeding Hills CIPs (under development) will include some standalone battery storage projects. In addition, the enabled capacity in the (pending approval) Plainfield-Blandford CIP could be used by standalone battery projects, with similar CIP provisions as solar projects. Batteries interconnecting under the standard interconnection Tarif would be subject to the Battery Schedules (See Section 9.1.4) and their discharge CIPs would be determined based on the maximum impact outlined in their specific schedule.

6.8.5. Equity and EJ outreach

The Company's EJ and equity outreach framework will be applicable to the Western Subregion and the overall framework is discussed in detail in Section 3.

6.9. New Clean Energy Customer Solutions

Clean energy customer programs will play a critical role in Company's roadmap to decarbonization. As described in this ESMP, a comprehensive approach to planning the grid of the future requires consideration of many solutions, including the potential contributions of customers in reducing demand and increasing system efficiency. These contributions are supported by a mix of existing and proven energy efficiency and demand response programs, initiatives currently under development, and newly proposed programs including in this ESMP.

With respect to existing programs, the Company will continue to provide customer programs consistent with current approved plans, such as:

- **Energy Efficiency.** The Company directs significant resources to provide residential, commercial, and industrial customers with incentives to improve the efficiency of their energy usage. Eversource, along with the other Mass Save Program Administrators (PAs), runs nation-leading energy efficiency programs. Since 2009, following the implementation of the Green Communities Act of 2008, Massachusetts has consistently ranked first or second in the nation according to the American Council for an Energy Efficient Economy's State Energy Efficiency Scorecard. These EE investments have resulted in substantial reductions in system-wide energy usage and peak demand.
- **Heating Incentive Programs.** As described in the 2022-2024 Mass Save Energy Efficiency Plan, following the passage of An Act Creating A Next-Generation Roadmap For Massachusetts Climate Policy (the "Climate Act") , PAs have engaged in an intensive effort to promote building end-use electrification, particularly in instances in which customer economics and building characteristics (e.g., displacement of delivered fuels or in specific new construction scenarios) favor the use of high-efficiency heat pump technologies.
- **Demand Response Programs.** Eversource, along with the other PAs that deliver the Mass Save programs, offers comprehensive Active Demand Response programs to customers. These offerings incentivize brief reductions in customer load during targeted periods of high system demand. By generating these system load reductions, the PAs can influence the long-term forecast that ISO-NE uses to establish the Installed Capacity Requirement. As a result, all customers benefit from the lower costs of a smaller generation and transmission system. These peak demand reductions also provide immediate benefits to all customers in the form of suppressing wholesale power prices during times of high demand, by reducing the system's reliance on what would otherwise be the most economically and environmentally expensive forms of generation.
- **Solar Massachusetts Renewable Target (SMART).** In partnership with the DOER, Eversource operates the Commonwealth's primary solar incentive initiative, the Solar Massachusetts Renewable Target (SMART) program. Under the SMART program, eligible customers and solar project owners receive monthly incentive payments from Eversource for the metered production of their solar installations. The program provides a long-term, fixed value incentive that builds on the Commonwealth's existing net metering incentive structure.
- **Electric Vehicle Charging and Incentive Programs.** The Eversource EV Phase II Program (approved in D.P.U. 21-90) is a comprehensive set of offerings designed to support the growth of electric vehicles in the Commonwealth of Massachusetts, providing incentives to support the deployment of electric vehicle charging stations in the residential, public and workplace, and fleet customer segments. The Phase II Program builds upon the Company's first Program by providing offerings to meet the diverse needs of all the Company's customers, building the infrastructure required to support statewide EV adoption, and helping to enable the Commonwealth's broader transition to a clean transportation future. Key elements of the Phase II EV program are:

- **Residential EV Charging Program:** provides rebates to customers to offset the cost of installing 240V wiring upgrades at their property for home EV charging, which is needed to support a residential Level 2 (L2) charger.
- **Multi-Unit Dwelling (MUD) EV Charging Program:** provides rebates up to 100% of the cost of the utility side and customer side infrastructure for EVSE installations at residential properties with five or more units.
- **Public and Workplace EV Charging Program:** supports commercial, industrial, and governmental customers to install L2 and Direct-Current Fast Chargers (DCFC) for use by stakeholders of the host locations, such as customers, employees, and other visitors.
- **The Fleet EV Charging Program:** supports the installation of L2 charging stations to support customer light duty fleet electrification. This offering provides up to 100% of the cost of the utility side and customer side infrastructure for EVSE installations.
- **Demand Charge Alternative:** this is an EV Pricing offering that is designed to support the adoption of EVs in the Commonwealth by reducing the impact of demand charges on low load factor EV charging sites.

The Company is also developing several offerings that will expand on these proven programs.

- **Managed charging programs:** With a forthcoming managed charging program proposal, the Company plans to offer both passive and active managed charging programs. Like economic signals provided through time-differentiated rates, the passive managed charging program will provide incentives to motivate customers to shift their charging to off-peak times. The Company views a passive managed charging program as a tool to bridge the gap until time-differentiated rates can be widely offered to residential customers. The Company expects active managed charging programs to remain crucial to enable charge management at a local level that cannot effectively be achieved through rates.
- **Solar programs.** In July 2021, Eversource filed a proposal for an Eversource Community Solar Access Program, or ECSAP, with the DPU. The intent of the program is to reduce barriers for income-eligible households to participate in community shared solar projects and encourage more development of SMART community shared Solar Tariff Generation Units by simplifying the billing and credit transfer processes experienced by system owners and participating customers.
- **Advanced Metering Infrastructure (AMI) programs.** As a part of its approved AMI program, the Company will execute a marketing and outreach campaign to explain the benefits of AMI and how they can benefit with access to their granular usage information providing insights into opportunities to reduce bills with energy efficiency, demand response or clean energy technologies.

In this ESMP, the Company has proposed programs that will increase customer engagement in clean energy solutions.

- **Grid Service Compensation Program (Section 6.3.2).** The Company is proposing to establish a fund to compensate stand-alone front-of-the-meter DER facilities and smaller behind-the-meter facilities to participate in a virtual power plant program aimed at addressing local capacity or voltage constraints on the distribution system. Customers with flexible load will have the opportunity to lower costs by helping the Company to address needs on the system.
- **Affordable Solar Access Program (Section 6.1.7.2)**. Under the program, multifamily affordable housing landlords and income-eligible residents in owner-occupied properties would select a solar installer from a pre-vetted list of installers offering standard pricing. Like existing Solarize programs originally pioneered by the MassCEC, installers would be competitively selected through a community-advised RFP process. Once selected, installers would be required to sell and install projects with the highest consumer protection standards and associated production guarantees. Solar project costs would be covered by an upfront payment from Eversource, meaning income-eligible and affordable housing customers would have no up-front costs to install solar. Participating customers would re-pay the initial investment via monthly on-bill charges.

7.0 Five-year Electric Sector Modernization Plan

Section Overview
Delivering the benefits of a safe, reliable, resilient grid that enables a clean energy future will require targeted, cost-effective investments in several areas. Over the 2025-2029 ESMP term, the Company's plan includes electric operations investments to improve reliability and build out the capacity required to support electrification and increase system hosting capacity as well as clean energy enablement programs, including the transition to advanced metering infrastructure. The Company is proposing new programs to accelerate the integration of solar and other distributed energy resources and to make meaningful gains in protecting the system to better withstand the impacts of climate change. The customer benefits of this plan are similarly diverse, including gains in safety, reliability, resiliency, integration of distributed energy resources, and enabling the grid to meet the demands of electrification. Addressing the need to manage rate impacts to customers, in total, the Company's investment plan remains essentially flat over the ten-year term. Further, the Company's plans are designed to maximize cost effectiveness by delivering benefits using data-driven approaches that prioritize the highest value opportunities for customers, ensuring that the specific needs of environmental justice communities are considered. Risks to executing this multi-faceted plan, including siting, supply chain and workforce constraints, will be addressed by scaling the Company's proven approaches to planning and implementing large infrastructure initiatives.

7.1. Investment Summary Five-year Chart

The 2025-2029 ESMP includes multiple categories of investments that will improve the safety, reliability, resiliency, and clean energy enablement capabilities of the Company's electric distribution system, delivering value to customers on many fronts. Combined current plan and proposed capital expenditures total $6.1 billion over the ESMP five-year term.

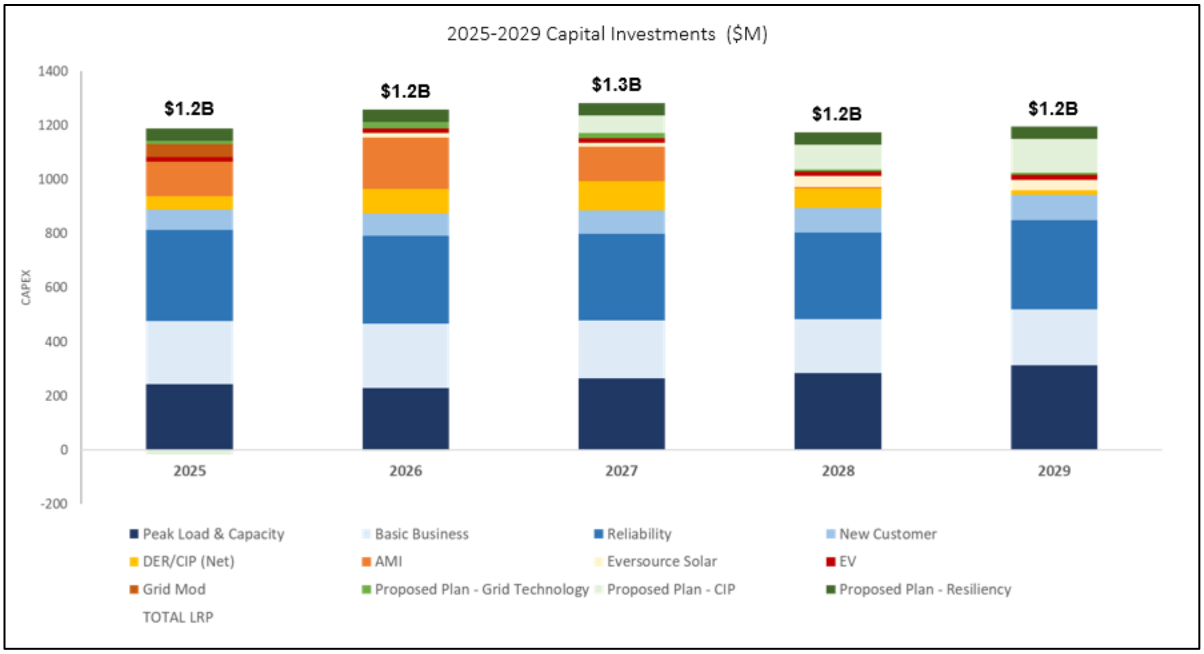


Figure 182: 2025-2029 Capital Investments ($M)

Capital investments are divided into the following three categories:

1. **Current Plan – Electric Operations.** Investments included in the Company's long-range plan funded through base distribution rates aimed at ensuring safe and reliable service to customers. ($4.5B)
    a. **Current Plan – Capacity.** Upgrades and new build of substations and distribution lines to accommodate load growth over the ten-year planning horizon
    b. **Current Plan – Reliability.** Upgrades to overhead and underground infrastructure to ensure reliable service, including hardening, conversions, aging infrastructure replacements, and automation
    c. **Current Plan – Basic Business.** Investments required to run the business, including capital repairs for storms or other damage, fleet vehicles, workforce tools, telecommunications, and information technology (IT)
2. **Current Plan – Clean Energy Enablement.** Capital investments included in the Company's long-range plan funded through dedicated mechanisms previously approved by the Department. ($1.0 B)
    a. **Current Plan – AMI.** Authorized investments in new metering infrastructure, communications infrastructure, and enabling IT systems, including a new customer information system
    b. **Current Plan – Eversource Solar.** Investments in Company-owned solar facilities, pending DPU approval and estimated to support new solar and energy storage facilities to improve climate resilience and support EJ communities

c. **Current Plan – EV.** Authorized investments to build out make ready infrastructure to support EV charging stations
d. **Current Plan – CIP.** Investments authorized and pending approval to build out infrastructure required to support DER interconnection in 6 CIP areas. One of the 6 CIP areas (Marion/Fairhaven) has been approved by the Department; the other 5 CIP areas part of the Current Plan – CIP are pending DPU approval
e. **Current Plan – Grid Mod.** Authorized investments through 2025 in field devices and operational technology to support the Commonwealth's established grid modernization objectives.

3. **Proposed Plan – Resiliency and Clean Energy Enablement**. Proposed capital investments to further support optimized DER integration and harden the distribution system against climate change threats. Investments included in this category are intended to further the Commonwealth's clean energy objectives. However, the proposed investments exceed currently approved distribution rate mechanisms and require further stakeholder review to ensure alignment and maximization of customer value. ($0.6 B). In order to move forward with investments in the Proposed Plan, as outlined below, the Company will require a supportive cost recovery framework in recognition of the fact that such investments are above and beyond the level of recovery supported by existing regulatory support mechanisms. Through the stakeholder process that will follow submission of this ESMP to the GMAC, the Company intends to work collaboratively with the GMAC to refine these Proposed Resiliency and Clean Energy Enablement Investments (as well as the incremental operating expense related proposals referenced below). Pending the result of that engagement, the Company intends to submit more detailed proposals for cost recovery of each of these incremental initiatives to the Department as part of its January 2024 ESMP filing with the DPU.
   a. **Proposed Plan – Grid Modernization Technology.** Capital expenditures to build technology platforms required to optimize integration of DER dispatch into control room operations and support advanced forecasting engineering. (See Section 6.3.2 for further description of proposed investments)
   b. **Proposed Plan – CIP.** Investments in seven additional CIP areas in the South and West regions. (See Sections 6.6 and 6.7 for further description of proposed investments)
   c. **Proposed Plan – Resiliency.** Incremental capital investments in hardening distribution system infrastructure to address impacts of climate change as identified by recent climate impact analysis. (See Section 10 for further description of proposed investments)

In addition to capital investments made to build out the distribution system, the Company's budget includes expenditures to operate and maintain the system.

2025-2029 Operating Expenses ($M)

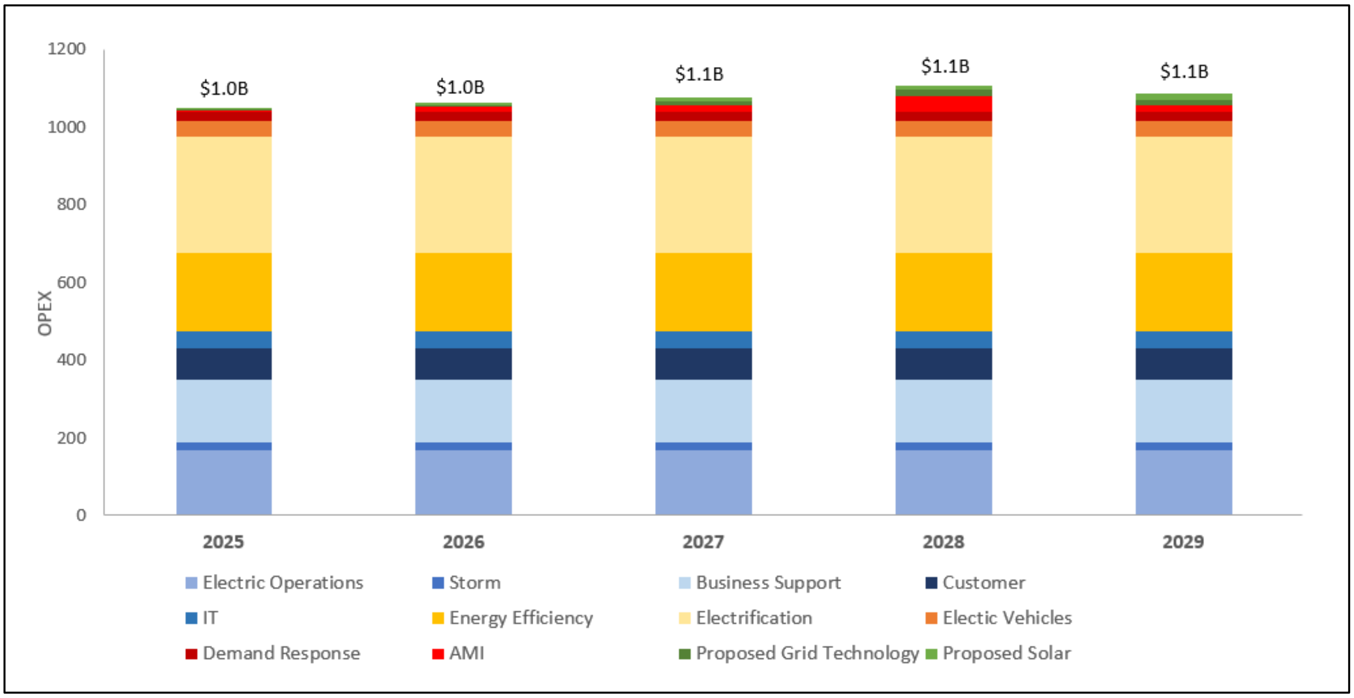


Figure 183: 2025-2029 Operating Expenses ($M)

Operating expenses are divided into the following three categories:

Current Plan – Run the Business. Spending included in the Company's budget for equipment maintenance and repair, major storm response, business support (e.g., human resources, accounting), customer support and call center, and information technology. ($2.5B)

Current Plan – Clean Energy Programs. Spending on customer programs to support energy efficiency, electrification, demand response, and electric vehicle charging. Note that spending in these categories is approved through separate dockets, on different timelines than the ESMP. Currently approved spending for the Mass Save Programs only extends through 2024; the 2025-2027 Plan will be submitted to the Department in October 2024. Similarly, Eversource's EV Phase II Program funding as approved in D.P.U. 21-90 only extends through 2026. Therefore, the spending shown in Figure 181: Agawam-Feeding Hills Cost Allocation and CIP Feeare estimates, included by the Company for completeness, and are not a commentary on expected outcomes of future dockets.

Proposed Plan – Clean Energy Enablement. The Company proposes incremental operations expense for the following programs. Similar to the discussion on proposed capital plans described above, in order to move forward with investments in the Proposed Plan, as outlined below, the Company will require a supportive cost recovery framework in recognition of the fact that the incremental expenses associated with the Proposed Clean Energy Enablement programs described below are above and beyond the level of recovery supported by existing regulatory support mechanisms.:

- **Low Income Solar Ownership.** As described in Sections 6.1.72, the Company is proposing an innovative financing program to support low-income solar ownership. The funding in this category allocates budget for program implementation and administration.
- **Grid Modernization Technology.** As described in Section 6.3.2, the Company is proposing an incentive program for front-of-the-meter DER facilities. Participation in the program enables the Company to dispatch grid services. The funding in this category includes incentive payments and program administration. Additional funding in this category provides for additional resources required for system planning and system operations to engineer support functions.

7.1.1. Alternatives to Proposed Investments – Estimates of Impact of Investment Plan Alternatives

The Company's five-year investment plan is comprised of three categories.

The first category, Electric Operations, represents the capital investments required to maintain safe and reliable service. This category includes investments that will address the need to expand system capacity to accommodate new loads, including loads driven by beneficial electrification. The Company's Electric Operations investment plan will establish a sustainable, cost-effective path forward, allowing the Company to continue to provide safe and reliable service as it manages the impacts of climate change and enables the Commonwealth's clean energy objectives.

The projects included in the Electric Operations budget are approved through the Company's established project authorization process. Project authorization includes the evaluation, decision-making, and approval of all capital projects in accordance with the Company's delegation of authority. Included in the project authorization process for each specific project is an assessment of the project need, a recommended solution, and an evaluation of alternatives to the recommended solution – both traditional and non-traditional. This evaluation of alternatives ensures that the funded solution addresses the identified need in a way that delivers the highest value to customers at the most reasonable cost. For example, for specific capacity projects, the Company uses a non-wires alternative assessment tool to assess the feasibility and cost effectiveness of non-traditional alternatives to adding substation or distribution line equipment and includes these results for review in the project authorization process.

As a part of the Company's base distribution budget, all Electric Operations investments are subject to prudence review by the MA DPU, following the date at which they are placed in service. Larger infrastructure projects are also subject to review and approval before construction by the Energy Facilities Siting Board.

The Company encourages stakeholder feedback as a part of its investment decision-making process, including alternative analysis. To be actionable, however, the timing of feedback is critical. Large capacity projects, for instance, take many years to plan, engineer, design, and construct. Projects described in Section 6 expected to be placed in service in the 2025-2029 period have established plans not subject to change based on new feedback. Projects expected to be placed into service after 2029, however, are currently in the planning and design phase such that the Company may be able to incorporate stakeholder feedback without significant re-design cost.

The second category is Clean Energy Enablement. Many of these investments have been approved based on prior deliberation on costs and benefits, including alternative assessments. For example, there is extensive documentation in the Company's 2022-2025 Grid Modernization Plan on alternatives to a full deployment of AMI, used to inform approval of the Company's proposal, which is now in the implementation phase. Some investments in this category, such as Eversource solar, will be the subject of review and approval for specific proposals in ongoing and future filings with the MA DPU.

The third category consists of the projects proposed as a part of this ESMP. The following is a summary of project alternatives.

- **Grid Modernization Technology.** As described in Section 6, these investments are aimed at increasing the Company's capabilities needed to incorporate DER as a grid asset to support local needs for capacity relief, voltage, and reactive power management. The alternative of forgoing or deferring these investments would diminish the potential of DER to provide grid services. The use of DER as a grid service is a cost-effective means to leverage existing assets with the capacity to provide value with minimal incremental cost. As the grid operator with oversight of real-time power flows, Eversource is in a unique position to identify grid needs and direct DER dispatch to meet system needs. Alternative dispatch models that are based on limited insight into real-time system needs will deliver lower value at a higher cost due to inefficiency. Absent Eversource oversight and control of dispatch based on system needs there will be an increased risk of causing negative impacts to the grid, particularly when the system is in an abnormal configuration. These investments are complementary to, rather than alternatives for, Electric Operations and CIP investments that will build system capacity and flexibility, enabling higher penetration of DER on the system. They are also complementary to other programs described in Section 6 related to load management and other methods for reducing demand for system-level peak reduction.

- **New CIP Areas.** As described in Section 6, the DPU established a new, provisional framework for planning and funding essential upgrades to the EPS to foster timely and cost-effective development and interconnection of DG, specifically areas with significant penetration of DG online or in the queue. The provisional framework allowed the electric distribution companies to file certain EPS infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities. Within the ESMP, the Company has identified 7 additional CIP areas beyond the 6 that have been presented to the DPU. The new CIP areas identified follow the prescribed criteria for EPS infrastructure upgrades and aim to provide the maximum outcomes for interconnection of DG in these areas. Alternatives to these investments for interconnecting DG would revert to the old methodology of funding interconnections (meaning, the costs of the upgrades would be borne entirely by the interconnecting customers, rather than allocated equitably between interconnecting customers other distribution customers).
- **New Resiliency.** As described in Section 10, the Company is utilizing its historical records of recent outages during major storms or resilience events to compile a list of grid vulnerabilities that are the targets of the Company's resilience projects. The Company is planning to utilize the results of the climate change vulnerability study to expand its target set of grid vulnerabilities. Specifically, the geographically granular results can reveal new areas where climate hazards peak (e.g., where temperature will be the highest (daily maximum or average) or where the highest precipitation is expected). The locations of the peaks of the expected forecasts will be the new targets of resilience work upcoming. The timing of the resilience need will also be factored in the pairing of the solution with an appropriate resilience project. These projects will be cost-optimal and highly targeted to ensure quantifiable benefits to Massachusetts' Environmental Justice communities. In addition, the Company will create a streamlined, robust, and repeatable planning process that is capable of periodically intaking new outage and circuit data to reflect ongoing and future changes to target areas. As described in Section 10, the Company's methodology targets resiliency improvements that will deliver the highest reduction in all-in SAIDI for the associated cost. These projects will also specifically target improvements in resiliency for customers in EJ communities. Alternative project selection methodologies risk decreasing benefits and/or increasing costs. Completely forgoing this investment category will result in longer major event outages and higher storm restoration costs. The Company's approach to hardening the overhead system to better withstand the stresses of major storms includes strategic undergrounding, vegetation management, and reconductoring. Assessments of the optimal solution to system hardening related to planning, engineering, standards, and work practices is ongoing and the Company will evolve its plan over time if needed to

reflect new information about the optimal strategies to achieve cost-effective reductions in all-in SAIDI.

- **Low Income Solar.** As described in Section 6, the Company has developed a program to provide financing to customers who meet certain criteria to acquire solar for their residences. This program is unique and would be a new way to encourage these customers to participate by providing on-bill financing for the purchase of these systems. The Company welcomes feedback on program design alternatives aimed at increasing benefits to targeted communities. Foregoing this investment, however, would reduce benefits and eliminate an opportunity to gather important feedback on best practices in encouraging solar ownership in EJ communities.

7.1.2. Alternative Approaches to Financing

As described in Section 6, the Department, in November 2021, issued Order D.P.U. 20-75-B, Order on Provisional System Planning Program ("Order"). The Order established a new, provisional framework for planning and funding essential upgrades to the EPS to foster timely and cost-effective development and interconnection of DG. The provisional framework allowed the electric distribution companies to file certain EPS infrastructure upgrade proposals with the Department that limit the interconnection costs allocated to these DG facilities. Under the provisional design, distribution customers fund the initial construction of these EPS upgrades. To balance this upfront cost, distribution customers are reimbursed over time from fees charged to future DG facilities that can interconnect due to the prior upgrades. These fees are specific to the CIP area. Additionally, a portion of the costs of the EPS upgrades commensurate with demonstrated operational reliability benefits are allocated to distribution customers.

The United States Department of Energy (US DOE) Grid Deployment Office (GDO), in conjunction with the Office of Clean Energy Demonstrations (OCED), made a Funding Opportunity Announcement (FOA) in March 2023. Awards made under this FOA will be funded, in whole or in part, by the Infrastructure Investment and Jobs Act (IIJA), also more commonly known as the Bipartisan infrastructure Law (BIL). The BIL is a once-in-a-generation investment in infrastructure, designed to modernize and upgrade American infrastructure to enhance U.S. competitiveness, driving the creation of good-paying union jobs, tackling the climate crisis, and ensuring stronger access to economic, environmental, and other benefits for disadvantaged communities (DACs). The BIL appropriates more than $62 billion to the Department of Energy (DOE) including funding to support investments that build a clean and equitable energy economy and achieve pollution free electricity by 2035. The BIL puts the United States on a path to achieve net-zero emissions economywide by no later than 2050. The Company has applied for funding for an AMI Clean Energy Microgrid in the city of Pittsfield. If the pending project application is successful, the Company would receive 50% cost share to reduce the revenue requirement associated with this project. This IIJA funding opportunity will continue in multiple rounds over several years and the Company will have the opportunity to submit additional applications in future years for certain investment that could qualify for funding under the BIL.

7.1.3. Customer Benefits

The Company's five-year investment plan will deliver a portfolio of customer benefits. The Company is working to produce a net benefits assessment, including qualitative and quantitative benefits to customers, and will file with the MA DPU in January 2024.

- **Safety**. Safety is a core value at Eversource. Empowerment and collaboration foster a safety culture where all employees can challenge the "way we've always done it" to introduce opportunities to minimize risk through a pro-active approach. Safety is a part of the Company's thinking, behavior, and expectations every day. Every project to design, build, or maintain an Eversource asset considers opportunities to keep employees and the public safe. Investments to replace aging infrastructure eliminate older equipment, such as antiquated oil switches, that have a higher operational risk profile than the current technology. Other investments deploy equipment using equipment standards and work methods that adhere to the Company's rigorous guidelines to ensure worker and public safety.

- **Transparency.** By providing a comprehensive view into the Company's full investment plan, the Company is ensuring stakeholders will have access to understand how all programs and initiatives work together to collectively deliver benefits to customers. Understanding the Company's total plan as a whole will support a robust stakeholder engagement process will allow interested stakeholders to proactively engage and have a voice on a just transition to enable clean energy.

  Grid reliability and resiliency. The five-year investment plan prioritizes investments that will improve reliability and resiliency, considering the added challenges associated with climate change. The Company's plan for 2025-2029 includes $1.6 billion to improve system reliability. This includes investments to replace aging infrastructure more prone to failure, distribution automation to support a self-healing grid designed to reduce the impact of outage events and hardening of areas with repeat poor performance. These reliability investments target improvements in the Company's existing SAIDI, SAIFI and CAIDI metrics. Further, as described in Section 10, the Company is proposing a new resiliency program to focus investment specifically on lessening the outage impact of major storm events and flooding. This program is targeting a 14% reduction in all-in SAIDI over ten years by investing in targeting undergrounding, vegetation management, and overhead storm hardening. In addition to its reliability and proposed resiliency programs, the Company's solar program is seeking out opportunities to support communities' climate mitigation activities through the deployment of solar generation in projects that support local reliability. The Company's AMI program will have additional benefit with respect to shortening the duration of major outages by providing greater situational awareness and giving first responders targeted information on the location of outages in real time.

- **Facilitation of the electrification of buildings and transportation.** Investments to expand electric distribution infrastructure, including substations and distribution lines, are foundational clean energy enablers, creating adequate supply to meet the needs of customers transitioning to electric transportation and heating. Absent the Company's investment plan, customers throughout the service territory will soon start to experience barriers to electrification. As described in Section 5, the Company has forecasted the expected loading associated with electrification, including heating and all classes of electric vehicles, while considering potential efficiencies associated with demand response. These needs form the basis of the five and ten-year investment plan for capacity growth. As a result of the plan, at the end of the ten-year period, the Company will have increased the headroom of the system to accommodate an incremental 2.5 GW of electrification load across its service territory. This effort will be complemented by the Company's energy efficiency and demand response programs that work to minimize loading from new and existing buildings. It will also be complemented by managed charging programs that minimize the loading impact of electric vehicles added to the system. These programs will be coordinated with the Company's introduction of AMI as a tool to empower customers to actively participate in clean energy programs, including time-varying rates. As enabling investments supporting electrification, the impact of these programs will include a measurable reduction in the Commonwealth's carbon emissions.

- **Integration of distributed energy resources (DER)**. Eversource has a longstanding commitment to improving the interconnection process and implementing projects to facilitate the integration of DER on its system. The Company's CIP initiative addresses the barriers to interconnection associated with studying DER interconnections sequentially under the cost causation principle. With limited hosting capacity at many of the key stations where customers are interested in interconnecting, an individual project would very quickly trigger substantial substation upgrades. If an individual project cannot pay for the upgrades, this leads to withdrawals, queue stagnation, and potentially stalls DER development in the region. If an individual project somehow pays for the upgrade, this leads to pervasive free-rider and inequity issues. The Group Study and CIP proposals resolve queue stagnation and free rider issues by fairly allocating upgrade cost to all customers who benefit from the upgrades, including distribution customers. In total, the Company's existing and proposed CIP initiatives will add an incremental 1.0 GW of bulk station hosting capacity to enable DER interconnection. In addition, the Company's other non-CIP bulk station upgrades will add an additional 0.9 GW of hosting capacity. Other initiatives aimed at DER integration in the plan include the Company's proposals to support the use of DER to provide grid services. These programs are intended to provide incremental incentives to new and existing facilities for the value they provide to the system, particularly dispatchable battery energy storage. All DER facilities benefit from a more reliable and resilient system. As enabling investments supporting increased DER penetration, the impact of these programs will include a measurable reduction in the Commonwealth's carbon emissions.

- **Avoided renewable energy curtailment.** The benefits described above related to DER integration will also help avoid renewable energy curtailment. Prior to entering into an interconnection agreement with a DER facility, the Company conducts impact studies to determine what, if any, system modifications will be needed to avoid the facility having an adverse impact on the distribution system. In some cases, interconnecting customers may choose an option to curtail output in certain hours to avoid triggering the need for more extensive distribution system upgrades. With increased system capacity due to the Company's CIP and other system upgrades, there will be fewer instances where facilities trigger the need for extensive system modifications and thus the option to be curtailed due to voltage or capacity constraints. Further, as a part of its 2022-2025 Grid Modernization Plan, the Company is investing in dynamic DER interface technology that enables remote communication and control of customer DER facilities. With this technology deployed at a DER facility, operating agreements can be established that reduce the number of hours a facility will require curtailment.

- **Reduced greenhouse gas emissions and air pollutants**. The Company's five- and ten-year plans allocated significant investment to initiatives that will directly and indirectly contribute to the Commonwealth's greenhouse gas emission reduction goals.

  The following are Company investments included in the five-year plan that will directly reduce greenhouse gas emissions.

  - **Eversource-owned solar**. Eversource owns and operates 22 solar facilities in Massachusetts, four of which beneficially repurpose landfill or other brownfield sites. Collectively, these facilities produce 70 MW of generation, enough to power more than 11,000 homes. Legislation was passed in 2021 that expanded utility solar ownership opportunities for both electric and gas companies in Massachusetts. Under this new authorization, Eversource is partnering with the communities it serves to develop, own, and operate solar projects paired with energy storage. As an initial step, Eversource has proposed three projects to construct parking canopy solar generation at the Company's area work centers in Brockton, Lawrence, and Yarmouth for a total of 5 MW of additional solar capacity. If approved, these projects, which are in environmental justice communities, will improve community climate resilience and contribute clean power to the regional electric grid during periods of peak demand.

- **System Efficiency and Line Loss Reduction**. Line loss is one of the electric industry's largest sources of indirect emissions. In 2018, as a part of its Grid Modernization Plan, the Company initiated a Volt VAR optimization (VVO) program to deploy new distribution line equipment and centralized software to adjust power flows for greater system efficiency and reduce emissions due to line losses. On feeders where VVO has been deployed, the Company has seen a 2% reduction in energy use and 1.8% reduction in peak demand. In its 5-year plan, the Company is proposing to demonstrate the integration of battery energy storage into VVO schemes to gain further efficiencies. The Company will continue to deploy this technology across Massachusetts in the coming five years. In addition, the availability of AMI data will enhance VVO algorithms, delivering an estimated benefit of an incremental 2% energy savings.
- **Eversource Operations**. The Company's goal is to achieve carbon neutrality in operations by 2030 exemplifies the commitment to be an industry leader when it comes to addressing climate change. To meet this ambitious target, the Company is taking a holistic approach to evaluate all opportunities for reducing emissions. By fostering an innovative and collaborative approach to enhance efficiencies and introduce new technologies, the Company is driving emissions as low as possible with an intent to limit the amount of emissions that will need to be offset. For example, over 22% of Eversource's bucket trucks utilized hybrid technology by the end of 2022. Looking ahead to 2023, Eversource aims to continue to expand Eversource's fleet with hybrid vehicles, with a formalized goal to have 100% of Eversource's bucket trucks utilizing hybrid technology by 2030.

The following are the Company's 5-year plan investments that lead indirectly to greenhouse gas emission reduction.

- **Energy efficiency and demand response programs.** The Company provides residential, municipal, commercial, and industrial customers throughout the service territory with top-tier energy efficiency programs. In 2022, the Company invested in customer energy efficiency programs, which continue to be the most economical way to avoids greenhouse gas emissions and aid climate efforts.
- **Investments to increase hosting capacity and enable DER**. The Company's approved, pending, and proposed CIP initiatives over ten-year period will add a total incremental 1.3 GW of bulk station hosting capacity to enable DER interconnection. In addition, the Company's other non-CIP bulk station upgrades in the ten-year plan will add an additional 0.9 GW of hosting capacity. Enabling solar and other DER will play an important part in achieving the Commonwealth's carbon reduction 2050 goals.

- **Encouraging DER as a grid service.** These programs, proposed as a part of this ESMP, are intended to provide incremental incentives to new and existing facilities for the value they provide to the system, particularly dispatchable battery energy storage.
- **Investments to increase headroom to support electrification of transportation and heating**. Through the ten-year plan, the Company will increase the electrification hosting capacity of the system to accommodate an additional 3.4 GW of electrification load across its service territory. This added capacity will enable adoption of electric vehicles and heat pumps, reducing carbon emissions in these sectors.
- **Electric vehicle programs.** The transportation sector is the largest contributor to the region's carbon footprint. Eversource is working to minimize carbon emissions with the advancement of Eversource's electric vehicle infrastructure programs. The MA electric vehicle program accomplishments through the end of 2022 include enablement of 4,272 charging ports through infrastructure installation or preparation. Of that total, over 2,000 commercial charging ports were successfully installed.
- **Avoided land use impacts.** Eversource fosters the long-term vitality of the land and promotes diverse native habitats through land management and preservation. The Company's transmission, distribution, and vegetation management divisions work to minimize the impacts of operations on habitats that support a variety of species within Eversource's rights of way (ROWs). Maintained ROWs contain important ecological features that promote ecological biodiversity and provide invaluable benefit to the region's flora and fauna. ROWs can act as conduits that facilitate the movement of animals in closely populated areas of New England. In forested areas, where the vegetation conditions of a ROW are much different than those in the surrounding land areas, ROWs can act as migration corridors for animals crossing from one patch of forest to another. By managing Eversource's ROWs for early successional habitat, Eversource promotes niche habitats that are essential to the conservation of many protected species of insects, plants, birds, amphibians, and reptiles. When impacts to the environment are unavoidable, Eversource's project specialists proactively seek out opportunities to mitigate impacts through high-value ecological restoration, enhancement, or conservation projects.
- **Minimization or mitigation of impacts on the ratepayers of the commonwealth.** Eversource recognizes the fiscal impact of electricity costs on customers. Focusing on four areas, the Company is working to minimize the costs of its plan to ratepayers.

First, the Company is minimizing costs of infrastructure with planning optimization. Establishing a sound plan for system upgrades avoids inefficiency and waste. Placing increasing focus on data-driven probabilistic analysis, the Company is ensuring the most important needs are addressed in the most cost-efficient way. For example, the Company's vegetation management programs use analytics to address the vast impact of trees on the overhead distribution system and prioritize the most critical areas for trimming. Analytics-based prioritization is also used to identify the aging equipment in greatest need of replacement. System planning engineers responsible for designing the system with sufficient capacity to meet the needs of load and generation, employ a comprehensive approach by understanding the interconnected dynamics of the system and analyzing needs over a ten-year horizon. Using this approach, the Company's five- and ten-year investment plan includes capacity investments that proactively meet future needs, avoiding inefficiency resulting from reacting to isolated near-term needs. The CIP programs exemplify this approach, increasing the efficiency and cost-effectiveness of DER interconnections versus the traditional "next in queue" process. The Company also utilizes standards that anticipate needs, including climate mitigation, that may emerge in the future, avoiding costly rework after the fact.

Second, the Company recognizes that planning the grid of the future will take multiple complementary approaches to ensure the most cost-effective solutions are implemented. In addition to the imminent need for system capacity driving the need for substation development, the Company is proposing to complement these projects with technology platforms and demonstrations to support the use of DERs. This is a cost-effective solution, leveraging existing and new customer-owned DER in a VPP approach that uses assets deployed for other use cases to provide grid services. This approach can combine both behind-the-meter and front-of-the-meter DER to meet capacity or voltage constraints, increasing system flexibility and potentially deferring the need for additional traditional system upgrades. In addition to using DER to address system needs, the Company conducts an alternatives analysis to ensure the chosen solution meets the identified need at the lowest possible cost. In some cases, this analysis results in a Company decision to pursue a non-traditional approach. In its five-year plan the Company has included two battery energy storage projects as grid assets to address loading and DER interconnection needs.

Third, the Company actively seeks out opportunities to empower customers to lower energy usage to reduce costs. Eversource's Mass Save energy efficiency programs for 2022-2024 are expected to have a total passive peak load reduction of around 20 MW per year. This reduction directly reduces energy costs for participating customers. The Company strives to make energy efficiency more affordable and accessible for customers. In 2022, incentives for moderate-income qualified customers in Massachusetts were enhanced to include support for heating and cooling equipment and upfront incentives to address health and safety issues in the home that prevent weatherization projects from moving forward. In addition, the Company is introducing the approved AMI program to all customers over the next several years. Once fully implemented in 2028, AMI technology will produce data and insights that can be utilized to create information and alerts for customers to better understand and manage their electricity usage and costs. With the introduction of time-varying rates following AMI deployment, customers with flexibility to shift load will have additional opportunities to lower their energy costs.

Fourth, in addition to developing a comprehensive infrastructure investment plan that enables electrification and clean energy at the lowest possible cost, the Company supports efforts to ensure costs are equitably shared among ratepayers. Through rate mechanisms, such as the low-income discount rate, a reduced percentage of costs are allocated to customers least able to pay. As described in Section 9, the Company supports additional innovations in rate design and incentive distribution to ensure that costs are equitably distributed and customers with load flexibility can reduce their energy costs by reducing their demand on the electric grid. Innovation in cost allocation, as exemplified by the CIP program, provides additional mechanisms to allocate costs equitably based on the degree to which customers benefit from system enhancements.

- **Improvements to the distribution system will enable customers to express preferences for access to renewable energy resources**. One of the key transformational investments included in the Company's five-year plan is the introduction of AMI for all residential and commercial electric customers. For customers, AMI will enable increased access to more granular usage information, improving the customer's understanding of energy savings opportunities. This information can be powerful for the customer when combined with new rate designs and participation in energy efficiency and demand-response programs. In addition, call center representatives would have access to more granular data. Access to additional data puts representatives in a better position to recommend participation in energy efficiency programs and help customers understand how changes in usage impact changes in bill amounts. With access to more detailed information and insights, customers will better understand how they may benefit from the adoption of renewable and clean energy solutions.

7.2. Investment Summary Ten-Year Chart

As shown in Figure 185 the Company's capital plan for the ten-year period 2025-2034 continues to invest in programs and initiatives to ensure safe, reliable, and resilient infrastructure that enables the just transition to a cleaner energy future.

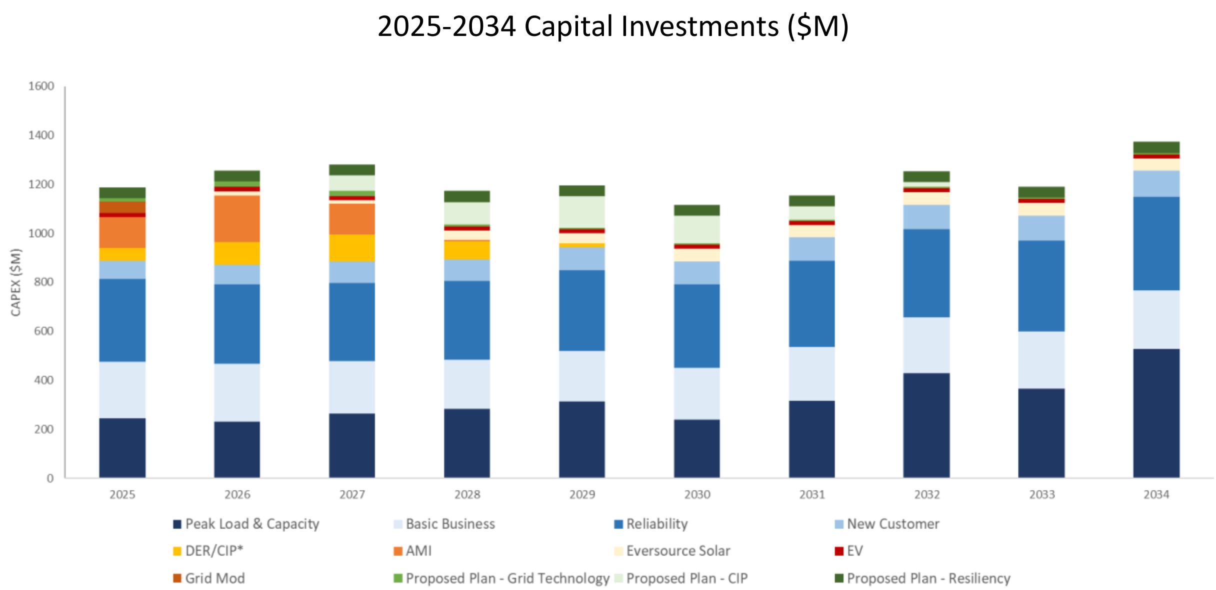


Figure 184: 2025-2034 Capital Investments ($M)

Among the drivers influencing spending in the ten-year period, certain programs, including AMI and approved DER/CIP, are largely complete by the end of the first five years. Spending in the second half of the ten-year plan is more heavily driven by peak load and capacity programs and proposed CIP.

7.3. Execution Risks – Siting, Permitting, Supply Chain and Workforce Challenges

7.3.1. Siting and Permitting Execution Risks

Eversource is planning the grid to enable a just transition to a cleaner energy future where the benefits of decarbonization are equitably distributed. This report underscores the urgent need to build infrastructure at a pace needed to meet climate and clean energy goals, including Massachusetts' aggressive commitment to achieve net zero greenhouse gas emissions in 2050. The ESMP projects described in this chapter will increase the reliability, resiliency, and capacity of the electrical grid.

Strong economic growth, electrification, and the influx of renewable energy are driving demand. The ESMP (Chapter 6.0 Figure 2) identifies major distribution infrastructure projects that will be needed through the ten-year planning period (2025-2034). The plan for 2025-2029 includes upgrades to six bulk substations and construction of five large substations. The plan for 2030-2034 includes upgrades to two bulk substations and the construction of nine large substations. In addition, the ESMP includes projects to enable up to 1.5 GWs of DER interconnection which will include upgrades to 14 bulk substations and construction of three bulk substations. The ESMP is focused on distribution; however, bulk substations will require increased transmission capacity at a similar scale. In addition to projects outlined in the ESMP, many new and upgraded transmission lines projects will be proposed as part of comprehensive solutions. In many cases, transmission infrastructure will be coordinated with substation projects and will be subject to siting and permitting review.

These large projects take years to plan, engineer, design, permit, and construct. If construction cannot keep up with demand, the Company is obligated to develop interim or emergency operational measures (e.g., load transfers, temporary spot distribution, battery storage). These temporary measures add costs and are less efficient and effective over time.

Siting and permitting are critical to getting these projects on-line. Chapter 4.0 includes an overview of siting and permitting electric infrastructure in Massachusetts and highlights challenges. Delays in reviewing and approving projects have increased significantly. As the volume and complexity of projects grow, so do the risks to implementing the ESMP. Timelines for siting and permitting need to be clear and enable the pace of infrastructure development needed to meet state decarbonization statutory targets, while ensuring an equitable process that includes those most impacted.

Eversource has developed strategies to address or minimize siting and permitting risks. Facilitating community engagement, soliciting constructive feedback, and building support for infrastructure projects is critical to securing local and state approvals. Eversource consults with state agencies, communities, and other stakeholders early in the project development phase to understand expectations, identify concerns, and explore opportunities. In cases where a project can be approved locally, effective consultation can reduce the schedule substantially. The Company has invested in and is expanding its Siting, Licensing & Permitting, and Project Services groups to support, timely, consistent, and complete project filings and to address issues and continue engagement throughout the review process (as appropriate) to keep pace with needed development. Once a project has been approved and permitted, the focus shifts to construction and compliance to ensure that commitments are tracked and completed. If changes are required, they are addressed appropriately and in compliance with laws, regulations, agency conditions, and approvals.

Considering the seismic changes in how energy is generated, distributed, and managed, reducing risks will require significant changes to siting and permitting processes. Siting and permitting agencies need much more capacity and increased efficiency to process, in parallel, the increased number and complexity of projects proposed to address demand. The Commonwealth recognizes that changes are needed to remove barriers to responsible clean energy infrastructure development and achieve climate and equity goals. It has established a Commission on Clean Energy Infrastructure Siting and Permitting (CEISP) that will make recommendations on administrative, regulatory, and legislative changes to existing permitting and siting procedures. The CEISP is charged with:

- Reducing permitting timelines
- Providing communities' input in the siting and permitting of clean energy infrastructure
- Ensuring that the benefits of the clean energy transition are shared equitably

Eversource supports this effort and looks forward to participating. Eversource will advocate for an efficient, rigorous, and consistent process that integrates constructive and equitable engagement within timeframes that enable achievement of Commonwealth targets and goals

7.3.2. Supply Chain Execution Risks

Like every company, Eversource is exposed to supply chain risks. Supply chain execution risks can be triggered by events upstream (that is, among suppliers) or downstream (among contractors) in the supply chain.

The biggest supply chain risks are global political unrest, economy and inflation, climate-driven disruptions, non-compliance issues, cyber threats, product and raw materials shortages, logistics challenges, and demand volatility. Eversource has experienced a combination of many of these contributing factors in the past several years.

Considering all CIP projects planned in various regions, the Company expects product and raw materials shortages to continue. This will lead to continued long lead times for everything from small tools to highly engineered equipment and a low percentage of successful on time delivery. In the current market, it is a challenge to create redundancies in the supply chain by adding new suppliers. Alternate manufacturers, who have not been used in the past, are either not interested in taking on new customers or have little capacity or bandwidth to take new orders. This makes the process of identifying new suppliers, piloting designs and processing sample orders challenging and slow. In short, the industry requires additional suppliers to increase the materials purchased to build out the infrastructure.

As Eversource moves away from the order-as-needed model to order-and-store model to mitigate product and material shortages, this creates logistical challenges. Eversource is faced with finding warehouse space and coordination to support routine returns of surplus project material and new material orders. Storage of project material in secure, sequestered locations is needed for advanced orders, storeroom material, and salvaged material. Additional storage will allow for material recycling and reprocessing when project laydown yards are not yet available to accept material. Having a large central yard, managed, and controlled by Eversource, allows for the orderly collection and secure storage of materials. Greater planning and collaboration are required prior to executing some of these large storage projects.

When it comes to supply chain execution risks, rapidly changing technologies will likely introduce challenges to ongoing equipment maintenance and future design considerations. For example, SF6 (Sulphur Hexafluoride) is a very potent greenhouse gas. Around 80% of the SF6 used globally is in electricity transmission and distribution. Medium- and high-voltage electrical equipment contains SF6 to insulate the live electrical parts and to switch the flow of electrical current on and off. Older electrical equipment may have higher leaker rates than more modern equipment. Due to the potent nature of this GHG, Eversource is currently piloting non-SF6 electrical equipment to help evaluate how SF6 may be phased out in the future. The Company is also beginning to address new equipment design that may require SF6 gas today but could accommodate an alternative non-SF6 gas in the near-term future. Currently, non-SF6 alternatives are expensive, and the supply chain industry is not yet equipped to fully support a rapid change. Eversource expects a slow adoption of non-SF6 alternatives, while needing to continue to maintain current SF6 equipment into the future. As the demand for SF6 changes, supply chain volatility with respect to availability of SF6 and non-SF6 alternatives will likely occur. States such as California ("CA") bans individuals from purchase or use SF6. However, this restriction does not yet apply to distributors even in CA. Utilities like Eversource will need to be prepared for stiffer regulatory requirements when using materials with SF6 the rise in prohibitions on the future use of SF6 is expected.

The current global political situation, exacerbated by the war in Ukraine and threats to Taiwan, could further strain the future supply chain. As nations discuss a new world order, new alliances will be formed, causing the loss of current alliances. This may require the Company to seek new suppliers. A current example is the Chip market which is constrained. Frequent evaluation of alternate sources, when specified items are not available, will lead to schedule impacts and change orders accruing additional costs.

Even though the US economy seems resilient, inflation is causing higher interest rates to tame the inflation. This will drive up the costs of materials and services required to execute these infrastructure projects. When estimating and forecasting project costs, project planners cannot depend on old trend lines. Higher than expected project costs will lead to greater scrutiny by regulators and rate payers.

As a New England-based company, Eversource's future planning could change, and the supply chain will need to adapt to these changes. This requires stakeholders to collaborate closely with each other to mitigate supply chain risks resulting from climate change.

In recent years, the New England States have experienced slower population growth compared to the nation. However, between the years 1958 – 2022, its population rose from 10.2M to 15.1M, for a net gain of 4.9M or 48.05% according to Bureau of Economic Analysis (BEA). The increase in population coupled with climate changes, will bring electric demand volatility to the market the Company serves. The impact of this volatility will bring supply chain execution risks that will require proactive mitigation on procurements and quantity.

Cyber security continues to grow and is a threat to the utility industry as more products in the field are software and cloud based. As the world grapples with how to deal with addressing these new threats, it could significantly hamper the supply chain since highly specialized material and services are involved in the electrical industry. As new supplier opportunities are explored, the Company must be mindful that states are establishing and acquiring controlling interest in companies that support Defense and Critical Infrastructure. Through this ownership, bad actors have the potential to influence the design and manufacturing of products, resulting in the potential for malicious code to be included in the software/technology or components.

Artificial Intelligence ("AI") is both a positive and a negative. AI will offer automation opportunities to remove redundancies that will free staff to perform more strategic work. However, AI's ability to duplicate voice and imagery may present security concerns in the future. As software manufacturers continue to move from permanent licenses to cloud based subscription licenses, the industry is exposed to a greater vulnerability from outside threats.

Community Solar is an innovative approach for all electricity customers to benefit from the monetary savings and environmental benefits of solar PV (Photovoltaics) without having to install these systems and carry the financial burden. According to the Solar Energy Industries Association (SEIA), the United States is expected to build over 4.3 GW of community solar projects in the next five years. One step beyond community solar is a community solar-plus-storage program (often solar PV paired with a battery energy storage system), that allows for even greater access to solar energy. However, this new market could also exacerbate currently exhausted supply chains by competing for many of the same materials, skilled labor, and services.

7.3.3. Workforce Challenges

Ensuring a prepared workforce capable of deploying and effectively operating cutting-edge grid technologies is a crucial component for a successful implementation of the ESMP. Although all utilities in Massachusetts are facing similar workforce obstacles, the following challenges have been identified by Eversource, along with the strategies adopted to address them.

Current employment market landscape

With historically low unemployment rates in Massachusetts, 2.6% in June 2023, employers such as Eversource do encounter a scarcer pool of candidates than in previous years.[2] Further, the employment market's landscape, which has been profoundly reshaped by the pandemic, currently tilts away from favoring employers. In response, Eversource does offer competitive salaries and class-leading benefits to attract new talent. This commitment is reflected in Eversource's workforce of highly skilled professionals, who enjoy a solid level of satisfaction, underscoring the attractiveness of the Company.

Long-term visibility into resource needs

Given the current dynamic nature of the employment market and the forthcoming hiring needs to modernize the grid, utilities do face specific hiring planning challenges. Eversource is adopting a long-term hiring strategic plan which does consider the specific needs of the Company. Working with community and engineering colleges, Eversource has devised a comprehensive approach to create pipelines for the grid workforce. This approach ensures the effective deployment of new technologies needed for the grid of the future. See section 12.2.

Upskilling the Company's workforce

Given the rapid and continuous evolution of grid technologies, utilities must constantly invest in training resources for their workforce. This ongoing process is crucial to cultivating skilled professionals capable of effectively deploying and operating complex new technologies. The Company provides a wide range of required and elective training programs on a regular basis to both field and corporate employees to continue to maintain and develop their skills. These programs are continuously updated to reflect the training needs of Eversource's employees as need change. See section 12.3.

Attrition and retention

Given the vibrancy of the Massachusetts employment market, attrition and retention can be a challenge for employers. Eversource experiences below-average attrition and retention rates which can be linked to its class-leading benefits, including union-benefits for some employees.

Diversity of new employee candidate pool

The Company is equally committed to sourcing from a highly diverse talent pool. Broadening the candidates' pool is a challenge faced among all utilities and businesses in other industries. Through the establishment of dedicated pipelines aimed at engaging environmental justice communities and organizations that represent underserved populations, Eversource aims to attract exceptional talents from a wide range of diverse candidates. See section 12.2.

As the hiring needs related to the ESMP change over time, Eversource has a highly skilled and motivated talent acquisition department which will evaluate, adjust, and scale hiring strategies and workforce development initiatives as required in partnership with other departments of the Company.

8.0 2035 - 2050 Policy Drivers: Electric Demand Assessment

Section Overview

The Commonwealth of Massachusetts has outlined ambitious objectives to decarbonize by 2050 in its Decarbonization Roadmap. While there are many different pathways to achieving these greenhouse gas (GHG) and net-zero emissions goals with varying impacts on the electric system, these objectives all have one thing in common – that they will increase demand on the electric system in unprecedented amounts by supplying all the energy needs that are today being met through statewide gas infrastructure, (liquid fuel distribution networks, and gas stations) via the electric power system. The base case of these demand increases shows the Company increasing its overall system electric demand from a 6.1 GW summer evening peak to a 15.3 GW winter morning peak by 2050. The majority of this 150% increase in electric demand by 2050 is driven by electrification of heating needs (about 50%) with the remaining driven primarily by electrification of transportation needs (25%) and normal load (25%). At a sub-regional level, the proportion of electrification demands between heating and transportation varies. The Western region sees a higher proportion of transportation electrification demand relative to Metro Boston, resulting from longer average driving miles and associated charging demand. On the other hand, the Southeastern region sees a higher proportion of heating electrification demand relative to other regions due to a significant amount of commercial space and larger homes. The ten-year planned large bulk substations have a significant impact on increasing the electrification hosting capacity offset by economic development driven demand increase. This drives the Western Massachusetts region to be best positioned to enable electrification followed by Metro West and then by Southeastern Massachusetts. Despite significant new bulk substation additions documented within Section 6, in Metro Boston and associated enablement of 2 GW of increased electrification hosting capacity, which, if the infrastructure is deployed as planned will still require about 900 MWs of additional electrification hosting capacity to meet the full 2050 electrification demand. In Metro West and Southeast regions, there is still approximately 1.7 GW and 1.6 GW capacity deficiency respectively needed to enable the full 2050 electrification future. In Western Massachusetts, the 2035 bulk substation upgrades enable the full 2050 electrification future.

Additionally, this Section also includes the Company's forecasts of solar – geographic solar development considering land costs, and interconnection costs in alignment with the Commonwealth's solar growth trajectory. The sub-regional solar forecasts are then layered in with available hosting capacities in these regions after the implementation of the 10-year plan. These granular sub-regional solar forecasts in turn inform the Company's planning framework to proactively upgrade the distribution infrastructure to enable solar above and beyond the interconnection queue.

Finally, because these forecasts of both solar and electrification are so significant, above and beyond the 10-year hosting capacity, the locationally-specific growth forecasts and associated pace of the growth are critical to informing the Company on where the bottlenecks will be and by when. This is why significant data-analytic and forecasting advancements have been put forth by the Company in building adoption propensity modeling approaches to deliver locationally specific forecasts.

There are a wide variety of factors that will impact the final load the Commonwealth EDCs will face in 2050 which are subject to state policies, local ordinances, and developments in technology, all of which the Company will address in the Section 9. To initiate a discussion on how these objectives can be achieved, and how different technologies and assumptions impact those goals, the Company has created its base-case based demand increase on the Commonwealth's "All Options" scenario with only Air-Sourced Heat Pumps (ASHP), as well as several sensitivity scenarios around deploying Ground-Sourced Heat Pumps (GSHP) or Hybrid Heating Solutions, including tradeoffs on costs, infrastructure need, and GHG reductions. This base case shows the Company increasing its overall system load to a winter morning peak at 9am of 15.3 GW by 2050. This contrasts with the 2023 base of 6.1 GW and a by 2033 expected build out of system wide available capacity of 10.4 GW. This constitutes an increase of more than 150% from the 2023 reference summer peak from Section 5. Figure 186 shows the expected makeup of the described morning peak.

With the projected peak for 2050 moving into the morning hours at 9am, several changes in the contributing load factors occur. First, the new base load moves significantly lower than the 10-year forecasted summer peak base, as the system has a lower winter morning load today. Second, the EV impact changes, specifically as shown later, by region, as the 9am charging peak is now driven more through workplace charging and fleets rather than evening commuter return. Lastly, the solar impact, even though there are significant incremental installations expected, stays at 325 MW for the entire installed solar fleet due to the impact of irradiance on the output, and the weather adjustments outlined in Section 5.

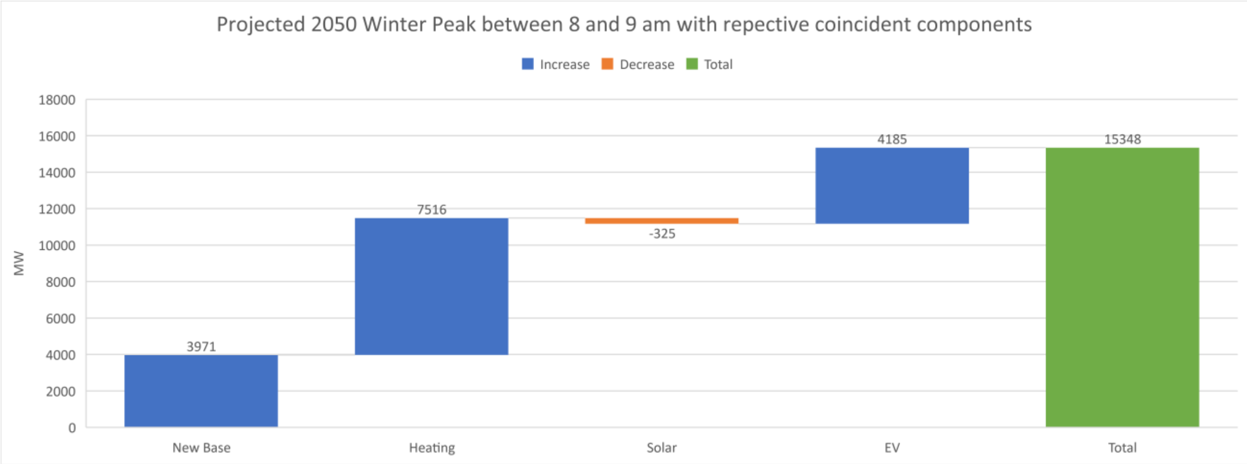


Figure 185: The 2050 Coincident Peak with Components

The load growth however does not appear uniform across the territory with the majority of the increase focused on the Metro Regions, which also have the lowest solar deferral capabilities. The following Figure 187 shows the waterfall charts by sub-region outlining regional differences. Especially well visible the significantly larger load increases due to heating in the Metro Regions, as well as the relatively high solar offset in WMA based on the current forecast (not adjusted for Capital Investment Projects, CIPs). It also shows the 2035 available bulk station capacity (red lines) relative to the total forecast.

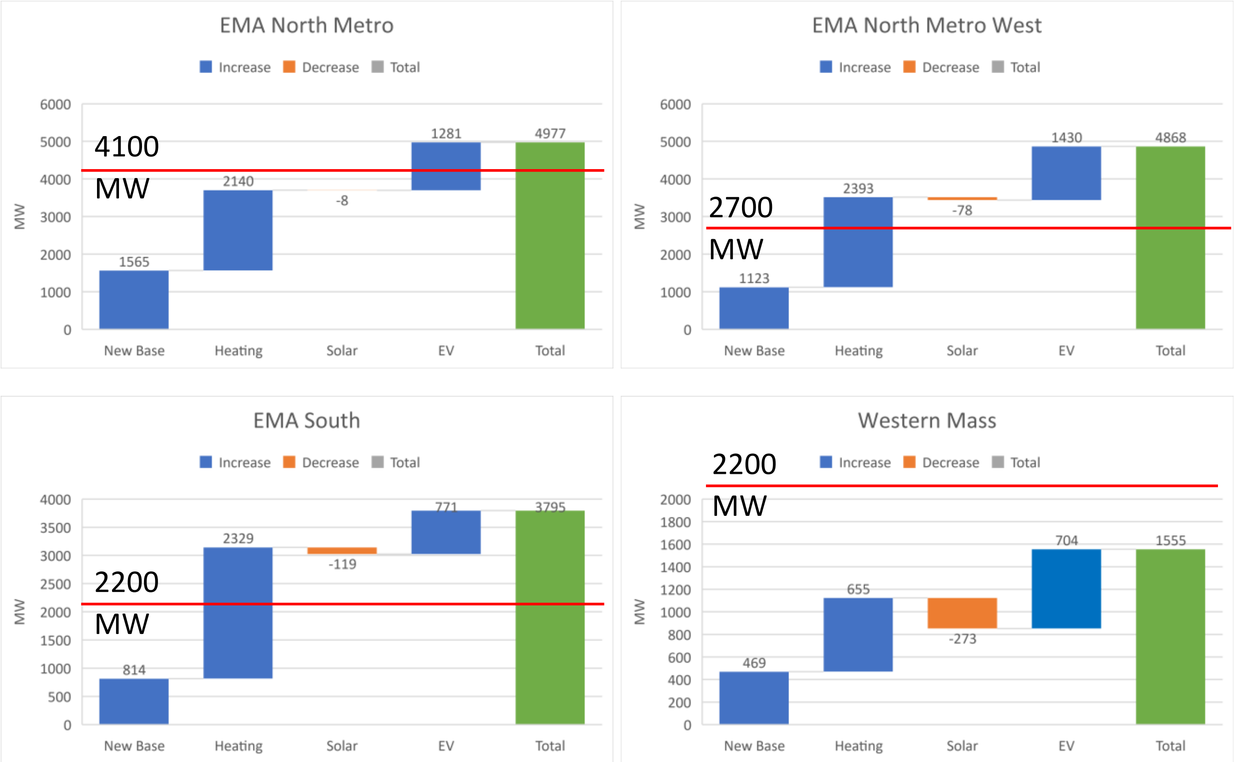


Figure 186: 2050 Peak Make up by Sub-Region at time of system peak

Methodology

The Company has developed an array of tools and models as part of its' Advanced Forecasting Capabilities. These innovations have been necessary to assess decarbonization impacts at various geographic layers and for various scenarios on the grid to ultimately inform an efficient distribution system plan. Central to the analysis used in the tools and models are the long-term policy drivers and state level goals for clean energy and electrification and the assumptions associated with the specific pathways and forecast models. The analysis begins with an evaluation of policy objectives for the state the assessment is created for. State and local government expectations are applied directly to the analysis where available. The state level objectives translate into Distributed Energy Resources in the form of total installed capacity (gigawatts of distributed generation), number of units of EVs, and Electric Heat Pumps, specific to the pathway to net zero emissions and decarbonization initiatives.

Once the policy objectives are translated into the respective components of electric demand at a state level they are broken down by geographic region (typically at a zip code level) using an adoption probability model which informs the placement of the policy driven resources across the system. This way, the long-term electrification demand assessment matches state and local policy objectives while ensuring a data driven approach to allocation of the resources on the system. The zip code level model determines the allocation of technology from zip code to zip code. Within the zip code, a bottom-up adoption probability model based on site specific and customer level data determines which customer sites adopt during a simulation. It is this zip code level of granularity that is critical to assess specific impacts on the distribution system – resulting from state policies. If specific incentives are designed or existing ones are re-designed to prioritize certain customers, the Company would work to include that in the model.

At each layer of the analysis, specific assumptions apply. For each technology, assumptions in regard to technical potential and adoption propensity is discussed in detail in Section 8.2, for heating electrification and heat pumps, Section 8.3 for electric vehicles, and Section 8.4 for photovoltaic (solar) and energy storage solutions. The Figure 188 below displays at a high level the layers of analysis for the 2050 long range electrification demand assessment.

State Level Analysis:

- Assumes the projections from state level pathways apply i.e.,
  MA 2050 Roadmap and CECP DPU MA 20-80 "Future of Gas" Study.
- Assumes a proportion of the state's projections fall into Eversource territory based on historical trends, technically available land, and number of structures or buildings.
- Load shapes are developed at the state level for each technology using various data sets (from industry studies, traffic data, etc.), for example, standard heating profiles for air source heat pumps or charging profiles for EVs. This assumes the load profile for individual technologies across the state.

Geographic Area (City, Zip Code) Level Analysis:

- Assumes local regulations or policy constraints apply at this level.
- The probability model is built with zip code data and customer socioeconomic variables to determine the probability of adoption in the geographic area of interest.
- If zip code level constraints or probability is not available or not applicable, the model moves on to customer Level Analysis.

Customer Level Analysis:

- Agent based simulation methodology uses site specific data to allow each site in the simulation to adopt a new technology at a given year, based primarily on economic parameters.
- Specific load shapes are created for technologies, which are then allocated to adopted customers and added up by sub-station to provide coincident load profiles.
- Customers are modeled as part of "clusters" (see Section 8.2.2 and 8.3.2) to be sorted by likelihood of adoption for each technology.
- Customer Level Analysis results can be grouped to circuit and up.

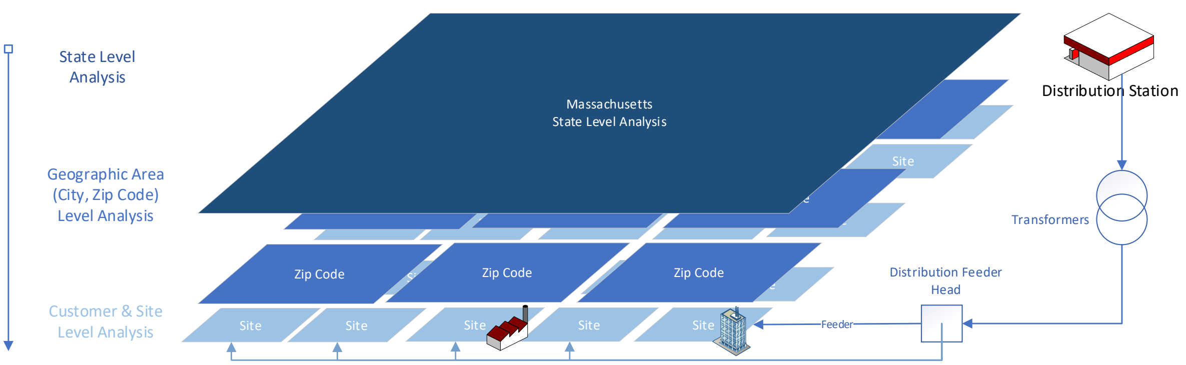


Figure 187: Electric Demand Assessment Input and Analysis Layers for Technology Adoption

The bottom-up adoption probability model and agent-based simulations follows the three-step process shown in the Figure 189 below. For all sites in Eversource territory, the site technical potential for is a DER and the probability of adoption is determined. Then, during an adoption simulation spanning the years of the forecast (2035-2050 for long term electric demand assessments), the adopters are iteratively assigned with the region of interest until expected adoption in the region is reached. The total annual incremental adoption is specified in what is called a 'guarantee' file, in other words, the number of adopters or energy required that is guaranteed by the simulation. This ensures that the minimum deployment projected for each year is allocated over the system. This allows the Company to assess where technologies are deployed while keeping the overall state level objectives in site. This locational assessment is crucial for the Company to prioritize its capital investments.

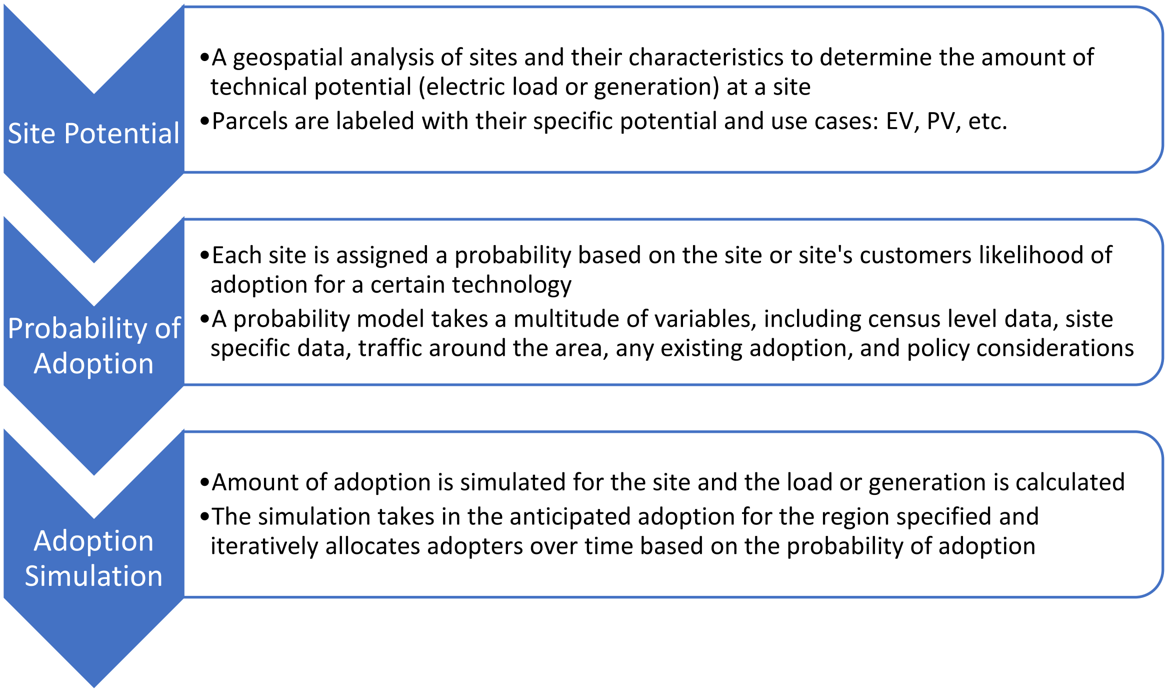


Figure 188: Process for bottom-up adoption probability and agent-based simulations

At the end of the agent-based simulation, a calculated load for each point is determined based on the site potential and number of adopters. The results of the agent-based simulation can be aggregated up to circuit level, distribution station level, and Eversource System level. The figure below shows the nodes in the model where load and generation data are available.

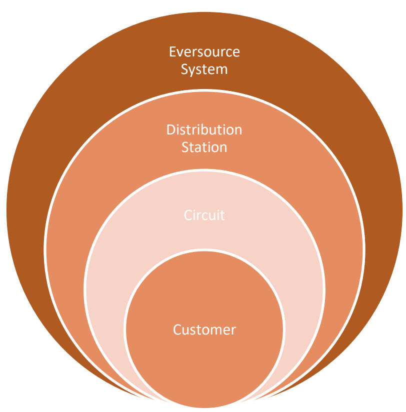


Figure 189: Electric Demand Assessment Output Layers for Electric Demand (Load and Generation)

Uncertainty

Within the long-term electric demand assessments there are certain assumptions the Company had to make in order to understand all of the impacts on the system. The base case assumes that the Commonwealth will achieve its goals based on the 2050 Decarbonization Roadmap following the "All Options" Pathway. Variations on impacts to forecast that create the highest uncertainty lie within the assumptions around heating electrification discussed in Section 8.2, and electric vehicles in Section 8.3. The Company will outline these impacts and is hoping to enable policy and law makers to understand those impacts and inform decisions.

8.1. Review of Assumptions and Comparisons across EDCs

The electric distribution companies (EDCs) in Massachusetts made up of Eversource, National Grid, and Until together has reviewed and compared overarching assumptions specific to future electric demand assessments across the Commonwealth. The overall strategy employed by each individual EDC shares many similarities, in particular applying and assessing the impact of state level electrification and clean energy projections for the buildings, transportation, and energy sectors. The EDCs adopt a scenario-based load assessment methodology and develop DER scenarios from the different decarbonization scenarios or 'pathways' outlined in the Massachusetts 2050 Decarbonization Roadmap[211] (the 2050 Roadmap) and the Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030[212].

For its long-term electric demand assessments, Eversource utilizes its Advanced Forecasting Capabilities (See the Section 5 Intro for details) across its Massachusetts service territory to assess the impacts of different scenarios on the power system. For distributed generation, the EDCs assess the All-Option scenario outlined in the 2050 Roadmap. This scenario is described as one that "selects the most economic resources to meet emissions limits using baseline cost assumptions". It provides an outlook on connected solar capacity, including both rooftop and ground-mounted, through year 2050. Eversource is actively researching the penetration and viability of long-term energy storage solutions in its territory. National Grid and Unitil assumes Energy Storage aligns with the 'All Options' pathway outlined in the 2050 Roadmap. For solar deployment, Eversource assumes all the newly installed solar capacity will be deployed on the distribution system as a base case. This does not change the location of those solar sites – but implies that when modeled on the Distribution system, Eversource would accordingly identify more Bulk Substation expansions – but ultimately if most of the energy transmits onto the

[211]Massachusetts Department of Energy Resources. "2050 Decarbonization Roadmap." *Mass.gov*, 2021, https://www.mass.gov/doc/ma-2050-decarbonization-roadmap

[212] Massachusetts Executive Office of Energy and Environmental Affairs. "Massachusetts Clean Energy and Climate Plan for 2025 and 2030." *Mass.gov*, 2021, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030

Transmission system, the resulting transmission constraints and associated transmission upgrades may not be different.

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

For the transportation electrification sector, Eversource looks at the same independent study as discussed in the above heating electrification sector. Transportation sector electrification is consistent across the multiple scenarios in the study and is based on the high electrification scenario/assumption. National Grid evaluates the load impacts of scenarios from adopting the California Advanced Clean Car (ACC II) Rule and Advanced Clean Truck Rule[213]. Both rules have been adopted by the State of Massachusetts and yield scenarios that align with the State’s decarbonization pathway. Unitil compared the details of its demand assessment (i.e. quantity of EVs, heat pumps, solar and energy storage) to the “All Options” pathway to ensure the demand assessment was in line with the decarbonization goals of the Commonwealth.

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

8.2. Buildings: Heating Electrification, Energy Efficiency Assumptions and Forecasts

Building Electrification, if fully realized to the extent modeled in the Roadmap, will be the largest single sector contributor to the Company’s system peak. Especially through its extremely high coincidence load due to an external trigger (relatively stable temperatures across the state,

[213] California Air Resources Board. "Advanced Clean Cars Program." *ARB.ca.gov,* https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program

and specifically in any given sub-region), building electrification is poised to force significant system re-enforcement. For 2050, in the Base Case of 100% ASHP and no retained fuel burning options (for e.g. hybrid heating), peak demand of electric heating is expected at 7am during winter days.

Hereby, as elaborated further in Section 8.2.1, the impact of electric heating is driven by “cold snap conditions” which the Company has defined as -5F. At -5F, the loads from heat pumps skyrocket as their efficiency decreases and the envelope heat demand from builds increases. It is therefore these very few days a year where these conditions exist that will define the need for the system based on the technology that was chosen. Figure 191 shows the load duration curve for the heating only component, as well as the underlying modelled heating load curve used by the Company. In Figure 191, it is visible that a very few days drive more than 50% of the entire heating demand causing a very low utilization rate of just 7% for infrastructure deployed for heating need. The Company will explore solutions on mitigating these impacts in Section 8.2.1 and Section 8.2.3.

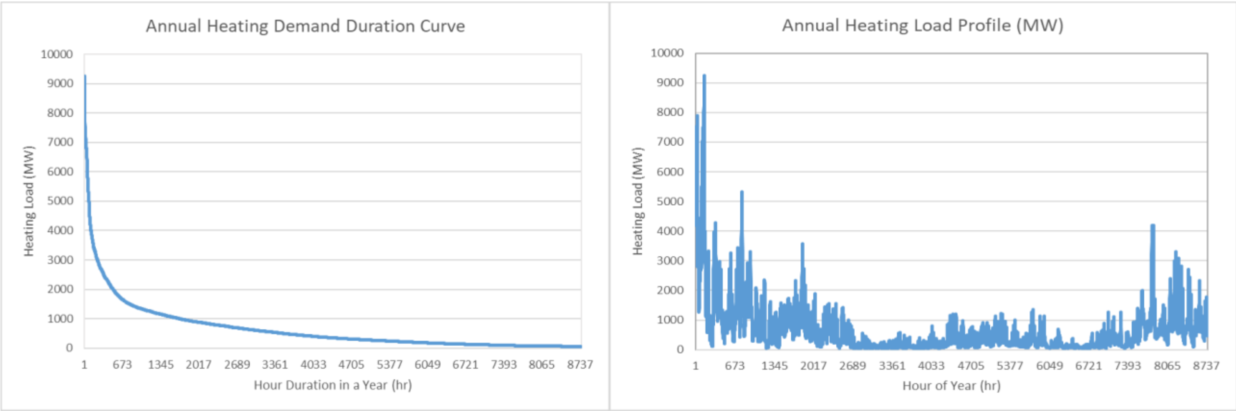


Figure 190: a) Annual Heating Demand Duration Curve
b) Annual Heating Load Profile

Overall, by 2050, the Company is expecting winter to peak in the early morning as a result of the mix of EV and heating impacts. Figure 192 below shows a sample day for a sub-region on how the expected heating profile. With heating peaking in the early morning as businesses and homes are heating up, the expected peak occurs at 7am. As discussed further in Section 8.3.4, this new heating load with its highest consumption during nighttime and early morning hours poses a significant challenge for deferral with distributed generation. It will also cause significant challenges with EV charge management applications that aim at moving nighttime charging around.

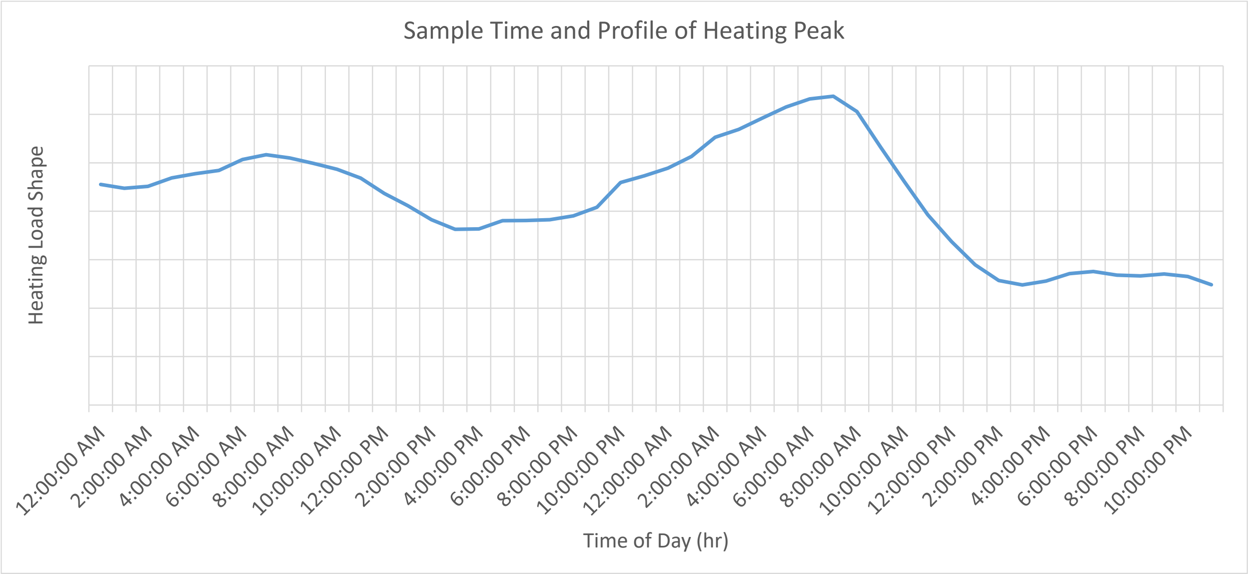


Figure 191: Sample Time and Profile of Heating peak

This shift has substantial impacts on the tools available to mitigate the peak. Solar, for example, will have very little to no direct impact on potential peaks. See Figure 192, which shows the clear sky irradiance data range for January and February in Massachusetts. Adding to the already low solar irradiance is the firm solar assumptions under Section 5 – Methodology.

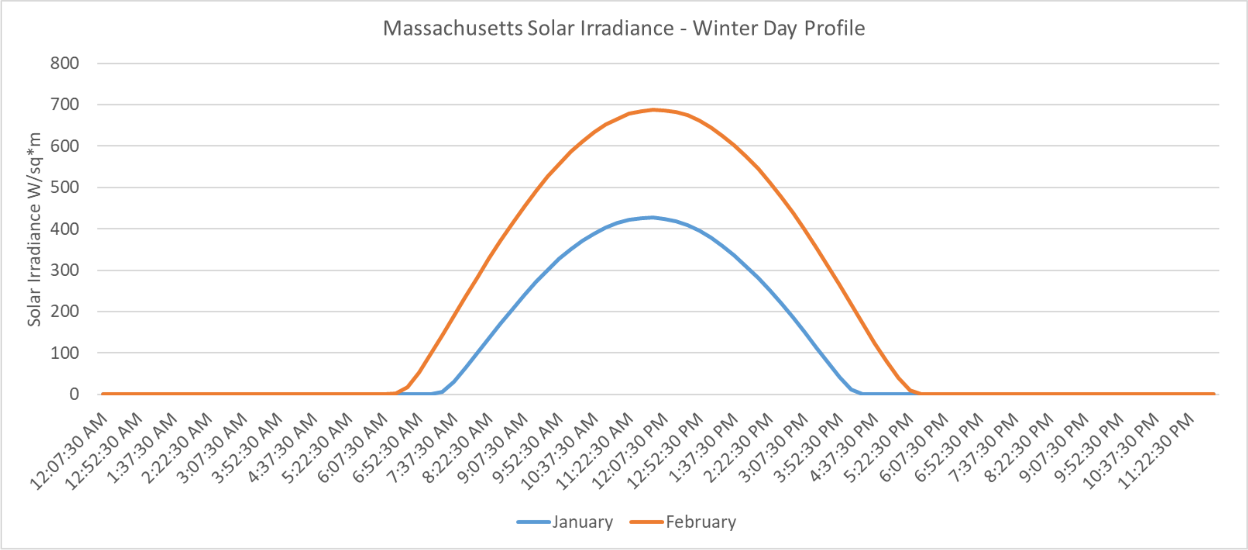


Figure 192: Massachusetts Solar Irradiance – Winter Day Profile

8.2.1. Technology Assumptions

While there are various technologies to decarbonize heating, the current predominant technology is air sourced heat pumps (ASHP). In order to produce a baseline electric demand assessment, the Company is using air sourced heat pumps as the core technology to determine a potential peak electric demand. From this base line scenario, sensitivity analysis can be conducted where assumptions on heating technology efficiencies can be varied to understand the impacts on the peak electric demand.

8.2.1.1 Air Source Heat Pumps

Although heat pumps are, effectively, just air conditioners running in reverse, electrification of heating significantly increases the electric demand requirement as compared to current summer AC load for two reasons:

1) The heating load of most buildings is substantially higher than the cooling load.

2) Heat pump efficiency is inversely related to outdoor air temperature.

During the summer, air conditioners usually overcome no more than a 20-degree differential between outdoor air temperatures and desired indoor temperatures (e.g. 95 degrees and 75 degrees.) During the coldest days of the winter, that temperature differential may be 70 degrees (e.g. -5 degrees to 65 degrees) or more. Therefore, the heat pump must be much larger, and requires much greater power, than an air conditioner would need to be for the same building. Compounding this impact is that fact that heat pumps are operating at their lowest efficiency during those coldest hours of the year (See Section 8.2.1).

Heat pump efficiency is defined by a coefficient of performance (COP), which is a measure of performance for a heating or cooling appliance. It considers Q, the heat that has been produced by the heat pump and W, the work performed by the heat pump. The calculation works by dividing the heat produced, Q, by the energy needed W.

$$\mathrm{COP} = \frac{|\mathrm{Q}|}{\mathrm{W}}$$

The COP is dependent on the delta in temperature between the source medium (outside air) and the heated medium (vented inside air). As external temperatures fall and the difference between source medium (outside) and heating target widens, the heat produced $|\mathrm{Q}|$ drops for the same amount of energy W consumed by the unit. In 2022, a study was performed by Cadmus[214] in which they analyzed ASHPs in Massachusetts and New York to determine customer satisfaction, heat pump efficiency, and grid impact. As a part of this study, Cadmus was able to collect meter data to measure the COP at various temperatures. The data shows that as the outside air decreases from 40 degrees Fahrenheit towards 0, the heat pump gradually becomes less efficient, and with a sharper drop in the COP once the air gets below 10 degrees. The average seasonal COP was estimated at 2.34 in the study conducted.

---

[214]Residential ccASHP Building Electrification Study." *e4thefuture.org*, 2022, e4thefuture.org/wp-content/uploads/2022/06/Residential-ccASHP-Building-Electrification_060322.pdf

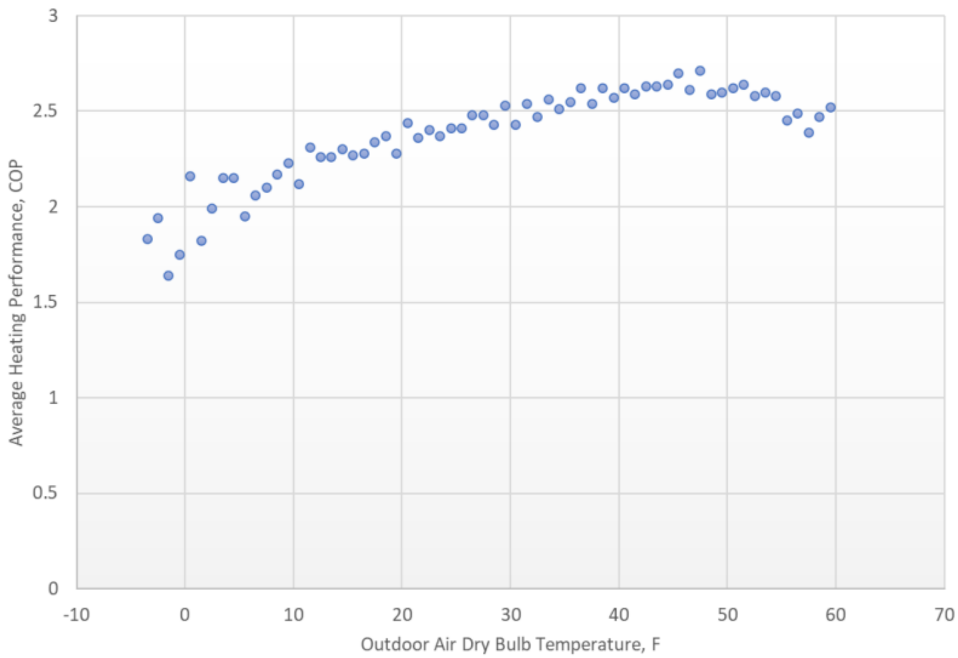


Figure 193: Coefficient of Performance of Air Source Heat Pumps in different outdoor air-dry bulb temperatures[215]

While data from Figure 194 shows clearly that today's ASHPs can and will drop below a COP of 2, the Company is conducting its long-range electric demand modeling using a COP of 2 as the "floor," or the minimum efficiency that a heat pump will operate at, on the assumption that there will be gains in technology and installation practices over the next decade. There are certain risks associated with incorrect installations or wrongly spec'd systems that have the potential to drive down the COP. If this happens at a sufficient rate across the system, a lower overall average COP will drive up system peak demand. The COP assumptions are modeled in the Advanced Forecasting approach as part of the adoption propensity layer in the guaranteed files (See Section 5 on forecasting methodology) with an average of 5 kW per residential load point.

8.2.1.2 Ground Source Heat Pumps

Another technology that can be used to electrify heating are Ground Source Heat Pumps (GSHP), which are sometimes referred to as geothermal heat pumps. GSHPs utilize a ground heat exchanger in order to trade heat with the ground. It is considered efficient due to its surrounding environment. Heat pumps rely on the temperature around them, and while the air in an environment may change drastically from season to season, the underground temperature is less volatile. This means the ground is colder than the air in the summer, but warmer than the

---

[215] Residential ccASHP Building Electrification Study." *e4thefuture.org*, 2022, e4thefuture.org/wp-content/uploads/2022/06/Residential-ccASHP-Building-Electrification_060322.pdf

air in the winter. There are multiple models of GSHPs that vary based on the surrounding environment where the GSHP will be placed. The types are Horizontal, Vertical, and Pond/Lake which are considered closed-loop systems. A closed-loop system is defined by its refrigerant, an antifreeze solution being pumped throughout the closed-loop and transfers heat between the heat pumps. Another type is an open-loop system which utilizes water to exchange heat within the system. The COP of ground source heat pump is generally between 3 and 6.

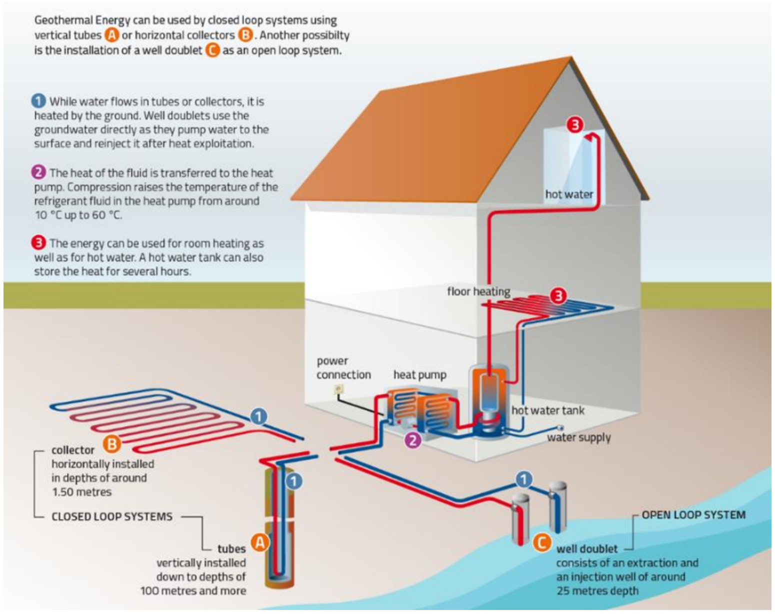


Figure 194: The inner workings of closed-loop and open-loop heat pump systems[216]

The Company currently models Ground Sourced Heat Pumps with a low-end COP of 3.5 resulting in an average residential point load of 2.85 kW, or 43% less than the equivalent ASHP. This is due to the fact that the source medium for the heat pump has a significantly lower temperature fluctuation and cannot drop as low as the source medium for air sourced heat pumps, making them significantly more efficient albeit at higher cost.

8.2.1.3 Hybrid Heating Solutions

ASHPs discussed above can also be installed as part of a Hybrid system. Hybrid heating solutions combine electric solutions with liquified fuel back up (Propane, Oil, Hydrogen, Biofuels) for the coldest days. In most hybrid installations, the liquid fuel system is used when outdoor temperatures drop below a threshold level, and the ASHP or GSHP is turned off.

---

[216]BioSun Energy. "Ground Source Heat Pumps." *BioSun Energy*, www.biosunenergy.co.uk/heat-pumps/ground-source-heat-pumps

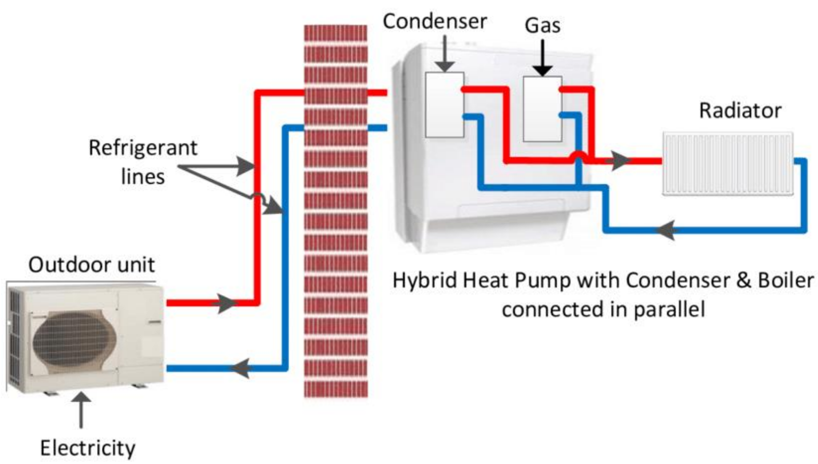


Figure 195: Shows the schematic workings of a Hybrid Heat Pump System.[217]

If implemented carefully, hybrid heating solutions could significantly reduce the required electric grid build-out associated with electrification, while still achieving much of the greenhouse gas reductions. The Company is currently considering three scenarios for hybrid heating solutions kicking in their (liquid) fuel back up once the external temperature reaches 10F/20F/30F.

The higher the minimum design temperature for the heat pump, the lower the impact on the grid. First, the heat pump can be sized smaller, and second, it will operate at a higher floor COP. In order to properly resize the expected heat pump and re-design the modeled unit, a basic approach through thermal conductivity is taken. q represents the local heat flux density (energy that is transitioning through a medium) and k a constant for the medium (that describes its ability to hinder heat flow). ∇T is the temperature difference between the temperature on both sizes of the medium, for houses this would be ambient temperature and in door temperature.

$$q = -k\nabla T$$

With the design need for -5F at 10kW (heating need) per 2000 sq-ft., and an internal target temperature of 72F, ∇T = 77F,resizing the heat pump to match a hybrid heating system would allow the design specification to be lower depending on when the hybrid heating system kicks in

- At 10F, ∇T is equal to 62 F. As a result, the sizing demand drops by 19.5% to 8.0kW

[217] "The Value of Hybrid Heat Pumps." *ResearchGate*, www.researchgate.net/publication/346506214_The_Value_of_hybrid_heat_pumps.

- At 20F, ∇T is equal to 52 F. As a result, the sizing demand drops by 32.5% to 6.8kW
- At 30F, ∇T is equal to 42 F. As a result, the sizing demand drops by 45.5% to 5.5kW

With smaller systems, and a higher floor COP of the system, the resulting modeled unit peak demand is decreased:

- At 10F, modeled unit is 8.0kW, a COP of 2.25 yields 3.6 kW, down 28% from the base case.
- At 20F, modeled unit is 6.8kW, a COP of 2.38 yields 2.8 kW, down 44% from the base case.
- At 30F, modeled unit is 5.5kW, a COP of 2.50 yields 2.2 kW, down 56% from the base case.

Figure 197 shows the average outdoor temperature curve for Massachusetts over the last 3 years – that is, the number of hours that the state experienced each temperature.

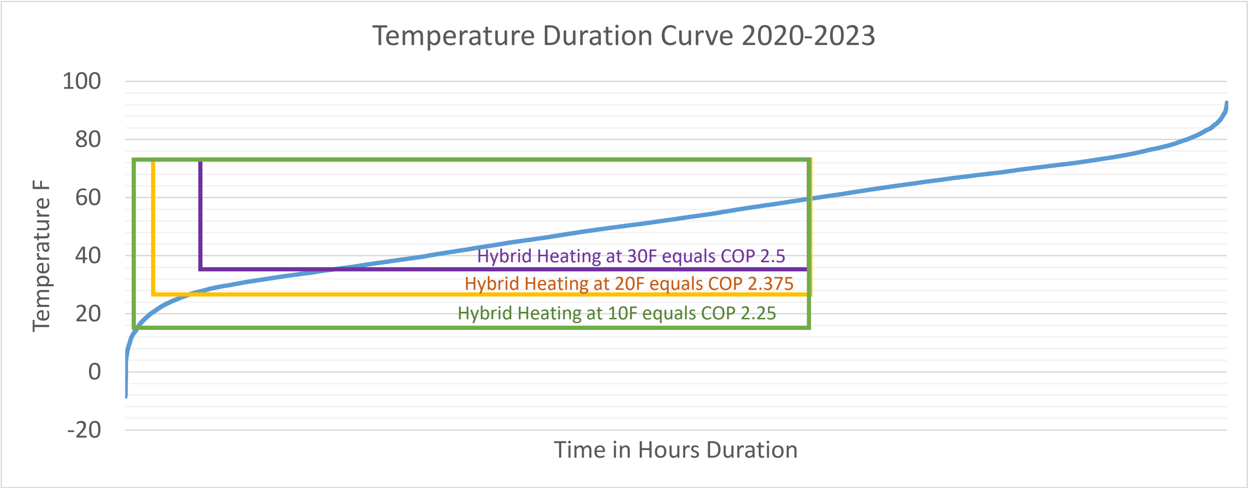


Figure 196: Temperature Duration Curve 07/2020 to 07/2023

Assuming that heating turns on at 60F ambient temperature, the resulting annual average heating hours where the backup system would be used and the associated GHG emissions reductions are:

- At 10 F, the total hours under back up system would be an average of 34 hours a year, achieving 95% of the GHG reductions as compared to a full replacement heat pump.
- At 20 F, the total hours under back up system would be an average of 201 hours a year, achieving 85% of the GHG reductions.
- At 30 F, the total hours under back up system would be an average of 845 hours a year, achieving 65% of the GHG reductions.

This scenario analysis can inform decisions about how to implement electrification in areas where grid capacity is constrained. For example, customers whose existing fossil fuel system is in safe operable condition could be encouraged to retain that system rather than decommission it at the time of their heat pump installation, and the customer could be enrolled in a load management program that allowed Eversource to send a signal to switch to the backup system if the grid is nearing system constraints. Such an arrangement would allow adoption of electrification to continue to occur at the pace necessary to meet the state's 2050 targets, achieving the majority of the short-term emissions reductions, while maintaining system reliability and lowering overall system costs, as well as allowing for more demand response capabilities.

8.2.1.4 Model Assumption

Within the simulation model, there are two main technology assumptions that inform the overall heat pump load consumption: the load shape and heating design capacity. Load shapes are developed at the state using standard heating profiles for air source heat pumps, ground source heat pumps, or hybrid heat pumps. This assumes the load profile of each technology is consistent across the state – in other words it reflects a typical use case for all consumers in Massachusetts. The load shape is a standardized profile over time; meaning it does not dictate the absolute value of consumption in units of power but rather the relative trend from a maximum peak over a specified time period. Therefore, the maximum load peak is scaled based on the technical site (customer point) potential since the load shape (see Section 8.2) does not change from site to site. During the agent-based simulation, a site is selected based on its probability of adoption, then site specific data is used to estimate load using the combined site technical potential, load shape, as well as the number of customers or heat pumps estimated for the site.

Currently, the default technology for residential sites selected for heating conversion is assumed to be an air source heat pump. The reference electric heating load is based on the heating design capacity at the design day temperature and coefficient of performance (COP). The reference electric heating design load assumed is 5 kW per residential heat pump customer for an average house size of approximately 2,000 sq. ft. in Massachusetts and seasonal COP of 2.34[218] and a floor COP of 2.

For commercial and industrial customers (C&I) the estimation of heating design load is more nuanced as the C&I category comprises of a wide range of applications, energy use intensities, and building use types. The approach to modeling is to again by default assume sites selected for heating conversion are assumed to be an air source heat pump. The reference electric

[218]"Residential ccASHP Building Electrification Study." *e4thefuture.org*, 2022, e4thefuture.org/wp-content/uploads/2022/06/Residential-ccASHP-Building-Electrification_060322.pdf

heating load is based on design day temperature, COP, and assumes the average commercial building size in the area of interest (using the 2018 Commercial Buildings Energy Consumptions Survey[219]). In all cases the load pump shape can be adjusted to reflect the load shape and performance of another technology or combination of technologies and can be useful in hybrid heating scenarios.

8.2.1.5 Technology Impacts on Model

As stated, the Company models its base case on the assumption of the achievement of the pathway laid out under the “All Options” variant of the 2050 Decarbonization Roadmap with 100% ASHP applications to displacing heating applications and a floor COP of 2. However, as outlined in prior sections under Section 8.2.1, a variety of technological variations can have different impacts on the final peak load in the model. Figure 198 below shows a visual representation of these impacts.

The main pane on Figure 198 shows the relative impact on the heating peak depending on a technology mix with the far-left corner representing the 100% ASHP solution without any hybrid heating components. This is the point of reference for all data in the graph and represents 100% of the modelled system impact. From there, the Z-axis (front to back) represents what percentage of heat pumps deployed are ASHP vs GSHP. As expected, the system impact drops and reaches 57% with 100% GSHP solutions. On the X-axis (left to right) the % of heat pumps deployed with a hybrid model cutting of at 10F is displayed. Starting in the far-left corner and tracing to the far-right corner Eversource traverses the 100% ASHP solution space with an ever-increasing number of hybrid systems in the mix and finally reach the far-right corner with 100% of the ASHP deployed as hybrids reducing the system peak demand to 74%. As GSHP system would not be deployed with hybrid solutions as the source medium is not compromised by colder weather, the impact from front left to front right remains stable.

In addition, the graphic shows the respective estimated impacts on upfront installation cost of the heating solutions relative to the 100% ASHP option. For this purpose, the Company, pending detailed data, is assuming double the upfront installation cost for GSHP and the same for ASHP Hybrid Systems. Shown in green, is the local avoided GHG, and in blue, the annual energy demand from the bulk system. As expected, GHG reductions are reduced to 95% with 100% hybrid systems rolled out, while the GSHP reduce the overall bulk system energy demand.

[219]"Commercial Buildings Energy Consumption Survey (CBECS)." *U.S. Energy Information Administration*, www.eia.gov/consumption/commercial/

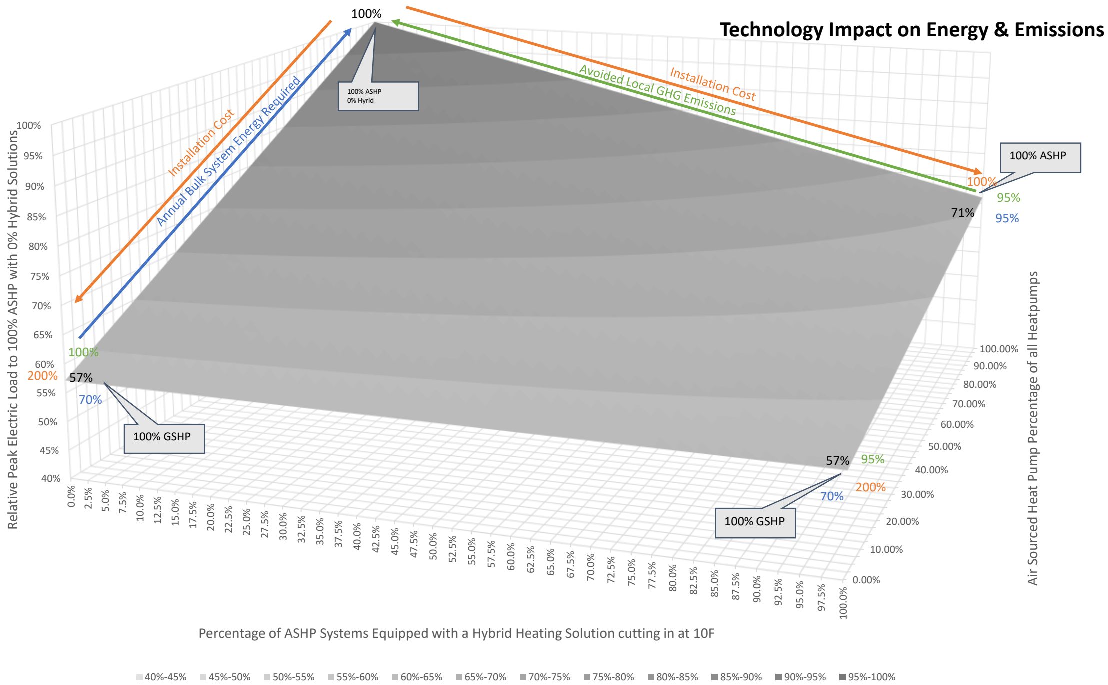


Figure 197: Technology assumptions impact on system peak demand, local GHG reductions, bulk system energy need, and upfront installation cost of the heating solution

8.2.1.6 Climate Impacts on Model

The Company has conducted a climate impact study up to the year 2050. As expected, and in line with the general understanding on how climate change will impact the global temperatures, significant increases in summer temperatures are projected as seen in Figure 199, which shows the 50th and 90th percentile for daily maximum temperatures in 2050. The Company is currently building models to better understand how these impacts will drive up summer cooling load, however, regardless of the impact, it is more than likely not going to eclipse the winter peak load. While this shows a dire picture and how the increased temperatures will drive summer cooling load, the sensitivity of system wide load to temperature does not equate to a 150% increase.

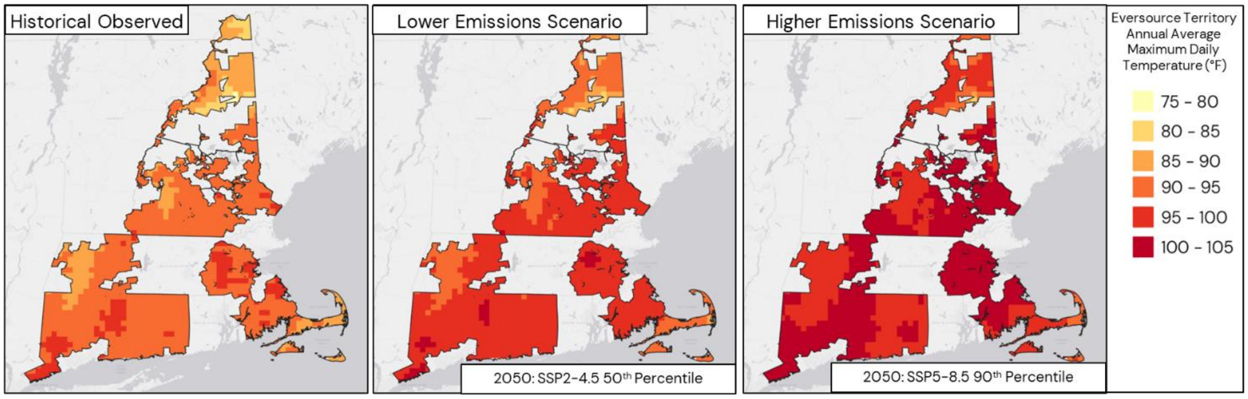


Figure 198: Extreme Heat – Daily Maximum Temperature Increase Projections

The challenging question is now around the winter peak load and if the peak load assumptions made to develop the model still hold in a warming climate. The Company had data generated on the annual number of days below the historical 5th percentile daily minimum temperature, Figure 200, which shows that, while the number of days is reduced, it cannot be ruled out. Consequently, for now, the assumptions hold that winter peak demand is measured at -5F. As the Company continues to improve its models, it will continue to update its data. Days below 5th and 10th percentile of minimum temperatures are projected to decrease by 16.6-27.8 days (SSP5-8.5, 90th percentile) in Boston by 2050 with less than 4 per year remaining in the high emissions scenario.

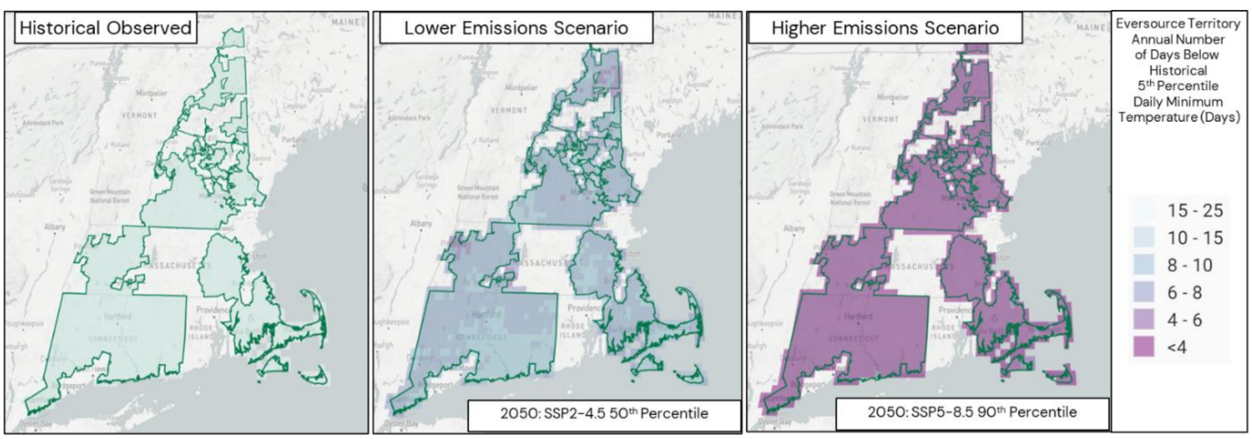


Figure 199: Eversource Territory Annual Number of Days Below Historical 5th Percentile Daily Minimum Temperature (Days)

8.2.2. Adoption propensity assumptions

By 2050 the state's objectives have almost all heating applications transition to an electrified version (based on the 2050 decarbonization roadmap "All Options" Pathway.) Therefore, the Company's assessment for heat pump adoption assumes more than 90% of buildings within Massachusetts will have adopted a heat pump by 2050. The Company utilizes the 2050 decarbonization roadmap, which is a High Electrification decarbonization pathway with the goal of electrification of more than 90% of buildings, mainly through air source heat pumps. Through the use of the High Electrification pathway, the Company adopts their yearly heat pump adoption goals assuming each year is what's needed to see full electrification by 2050.

However, the challenge for the Company with this data is that it does not show, station by station, when and where such a transition will happen. This, however, is critical for the Company to understand for the Company to properly prioritize its capital plans. Therefore, the Company introduced an Adoption Propensity Model. Adoption propensity models are used to determine one's relative likelihood of adoption. In the case of heat pumps, an individual's likelihood of adopting a heat pump is determined relative to their variables, or factors believed to drive heat pump adoption.

Customer Adoption Propensities

When applying Adoption Propensity Models to the heat pumps, the Company took the baseline approach that forecasted adoption of heat pumps is type-agnostic. Therefore, the number of heat pumps predicted year-by-year are considered as a number representing all heat pumps, not a specific type.

To develop a methodology for heat pump adoption, the Company merged Experian credit data with customer specific Eversource data. This allowed the Company to create a dataset to determine which individuals use different heating types, and what their socioeconomic factors are that might impact their likelihood to adopt. In conjunction with statistical tests, the Company conducted a mini-Delphi exercise with internal subject matter experts to determine which customer demographics are key indicators of heating adoption, yielding a total of 5 factors that the Company qualified as the key socio-economic factors that impact the likelihood of electric heating adoption. The identified factors are, in order of their relative impact on the adoption propensity[220];

1. Single Family: an individual lives in a single-family home.
2. No Gas Heating: an individual who doesn't have gas heating.
3. High Income: an individual that falls between the 75% and 99% percentile of income.
4. Age:
    a. Younger Age: an individual between the ages of 18 and 43
    b. Middle Age: an individual between the ages of 44 and 63
    c. Older Age: an individual older than 63 years old.

[220] These adoption clusters will be refined as the Company continues to get data on who is currently adopting heat pumps.

5. Newer Building: an individual who lives in a building no older than 25 years.

Since the source of data is derived from Massachusetts Eversource customer data, the Company is only able to determine which Eversource customers fall into each of these respective categories. From this, the Company assumed these individuals are representative of all Massachusetts residents, not just Massachusetts Eversource customers. As shown in the figure below, only 9% of individuals live in a building that was built less than 25 years ago. The Company also determined from the data that 25% of customers fall into the high-income category, 57% live in a single-family home, 14% are estimated to be between the ages of 18 and 43, 64% are middle age, and 22% are older age, and 65% don't have gas heating. Since this data has been merged with Eversource customer data, the Company assumes that the number of individuals falling into these categories of drivers also represents the totality of the state of Massachusetts. Each factor was assigned a ranking that represents how strongly it will drive heat pump adoption, where living in a single-family home is viewed as the factor with the greatest impact on likelihood to adopt heat pumps and living in a newer building is the smallest.

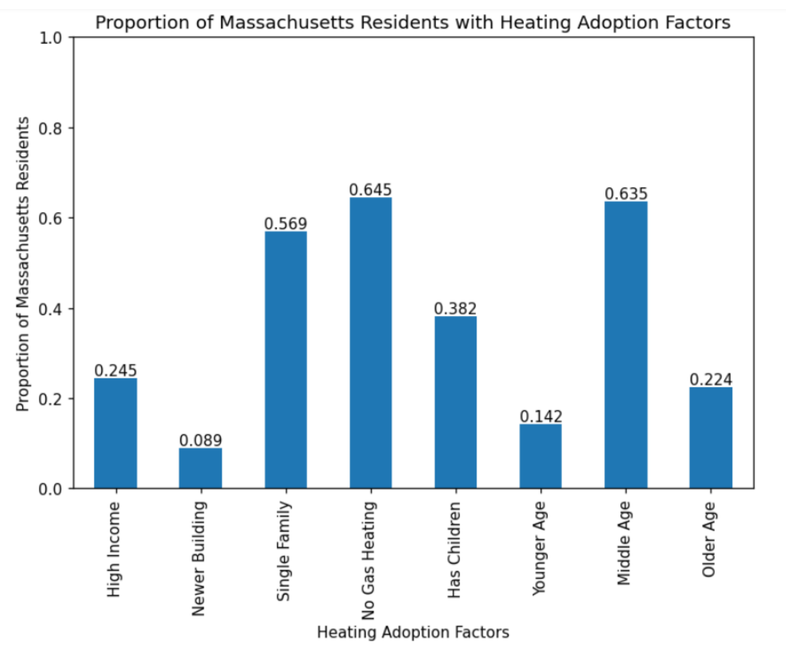


Figure 200: The proportion of Massachusetts residents who fall into each of the EV adoption driver categories.

Since the Company has data at the individual customer level, the Company can see if an individual falls into one of these categories or not. If an individual does, they receive a ranking number, where the higher the ranking number, the greater the driver. From there, the Company summed these individuals' scores to determine which individuals had the highest and lowest scores. The Company refers to this score as a priority score. All combinations of these scores were used to determine how likely an individual is to adopt heat pumps. See Figure 202 below for the scoring process, as well as Table 60 for a sample scoring card.

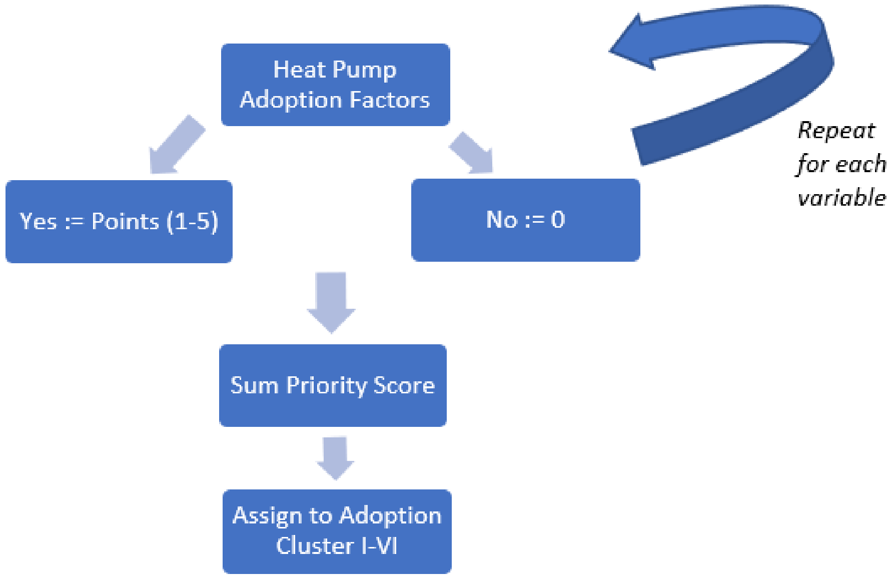


Figure 201: Heat Pump Adoption Propensity Model Process

Table 60: Heat Pump Adoption Propensity Example Customer Scores

Customer Example	Single Family Home	No Gas Heating	High Income	Age	Newer Building	Priority Score
John Doe	5	4	3	2	1	15
Jane Doe	5	4	3	2	0	14
John Smith	5	4	3	-2	1	11
Jane Smith	5	4	0	0	0	9

The Company then developed adoption clusters grouping customers based on their priority scores. Cluster I is assumed to be the fastest adopting group, whereas Cluster VI is assumed to be the slowest adopting group. For Cluster I, these are the "early adopters" and will have a priority score of at least 10. Cluster II consists of individuals who live in a single-family home and don't have gas heating but only have a priority score of 9. Cluster III are those who have a priority score of 9 and either live in a single-family home or don't have gas heating, but not both. Individuals with a priority score between 6 and 8 will also fall into Cluster III. Cluster IV individuals are those who have no gas heating and no other scores. Cluster V individuals have a priority score of 5, or a priority score of 4 and gas heating, or a priority score of 3. Cluster VI have priority score of 2 and below.

The Figure 203 below shows the proportion of customers that fall into each adoption cluster. Cluster III has the highest number of individuals at 24%, Cluster I at 19%, Cluster IV at 17%, 16% for Cluster II, 12% for Cluster V, and 12% for Cluster VI.

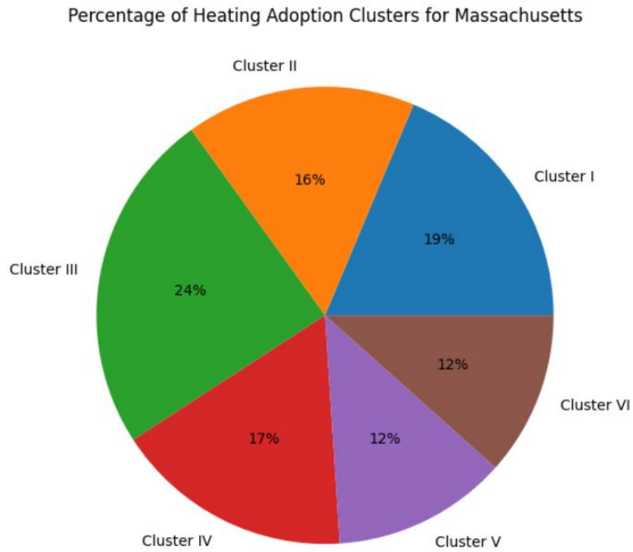


Figure 202: Percentage of Individuals from Massachusetts in Each Adoption Cluster

The following Graphs in Figure 204 a-d show the customer cluster split by each Sub-Region for the heating adoption with some stark differences between the likelihood to adopt the technology. Specifically, the Metro region has a very low early adopter component driven by access to gas and a high renter component.

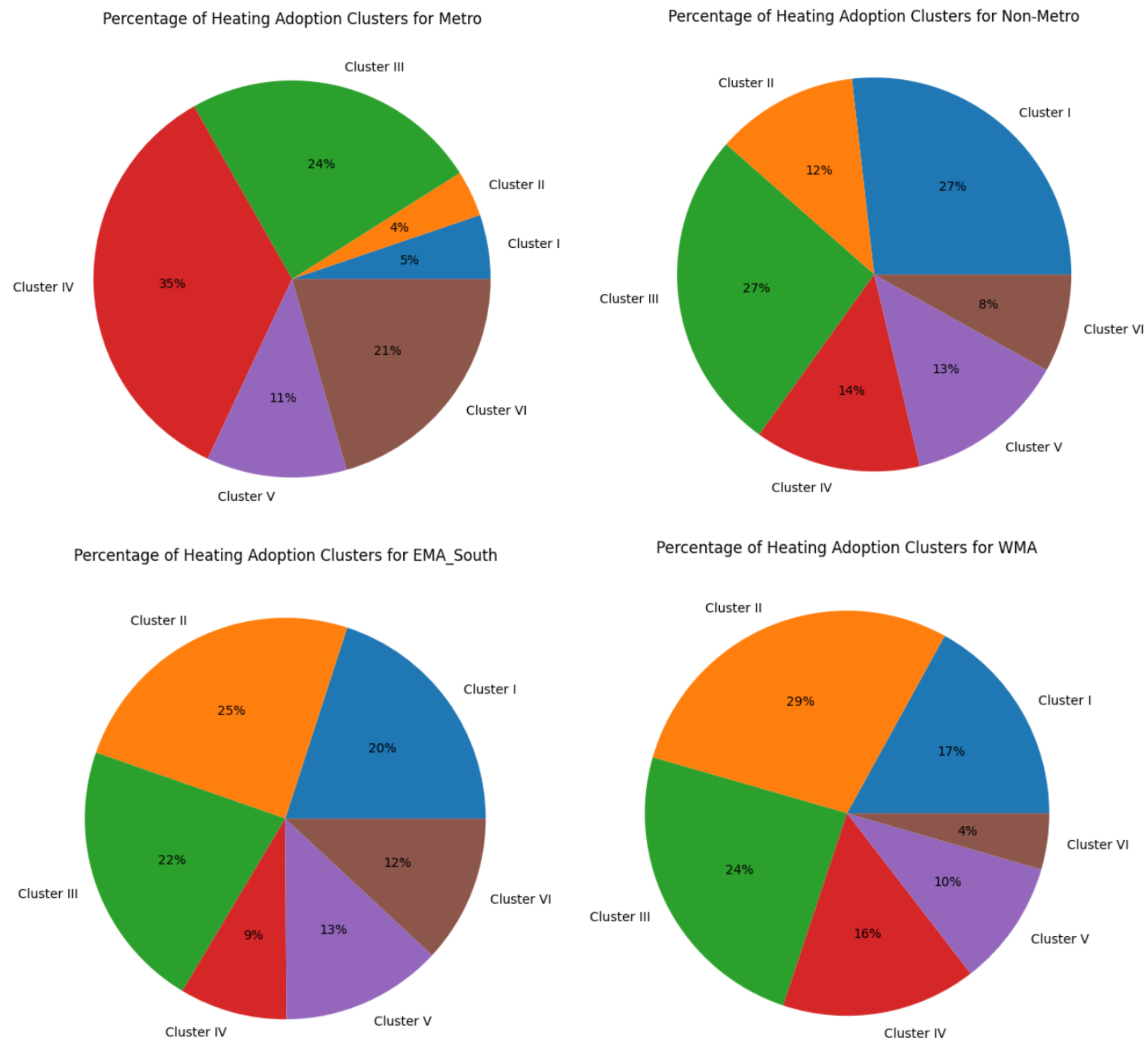


Figure 203: Heating Clusters by Sub-Region a) Metro b) Metro West c) Southern, and d) WMA

Once customers were grouped into clusters, logarithmic growth adoption curves were developed for each, with each curve reaching 100% adoption by 2050. Eversource assumes the logarithmic growth rate is greatest for Cluster I, and smallest for Cluster VI. These growth curves can be viewed as a probability cumulative function, where at the maximum year, 2050, Eversource achieves 100% adoption. Therefore, the Company views adoption as a function of time, meaning, the greater the year, the greater the number of adopters. The probability cumulative functions allow us to reference how many individuals from some cluster can adopt a heat pump given some year. The Company uses those references to sample individuals from each group and assign them to a cluster representing individuals adopting a heat pump for some year. The Company assumes that priority of sampling should be given to the adoption cluster with the highest growth rate. As it can be seen, since the growth rate is fastest for Cluster I and slowest for Cluster VI, then adoption reaches maximum capacity for Cluster I first and Cluster VI last. Figure 205 shows the modeled adoption propensities with Table 62 showing the years at which each cluster reaches a certain adoption level.

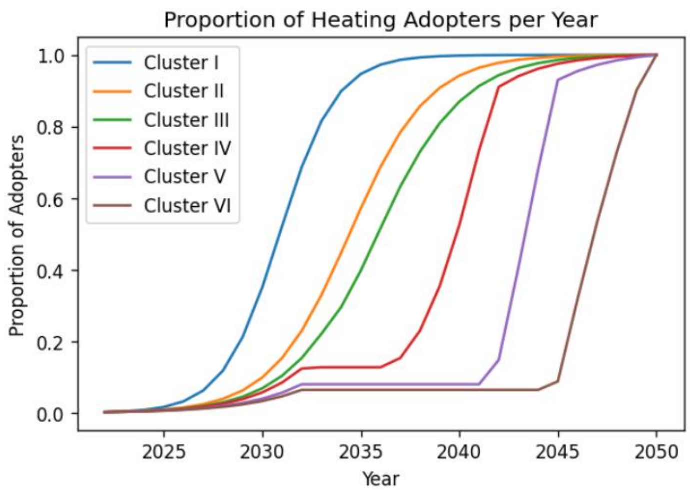


Figure 204: Proportion of Adopters for Each Adoption Type Relative to Time.

Table 61: Year Each Adoption Cluster Met Corresponding Adoption Percentage

Adoption Percentage	Cluster I Year	Cluster II Year	Cluster III Year	Cluster IV Year	Cluster V Year	Cluster VI Year
40%	2031	2034	2036	2040	2043	2047
60%	2032	2036	2037	2041	2044	2048
80%	2033	2038	2039	2042	2045	2049
90%	2035	2039	2041	2042	2045	2059
95%	2036	2041	2043	2044	2047	2050

Table 62: Percentage of Adoption Per Cluster Type Corresponding to Each Year

Year	Cluster I Adoption	Cluster II Adoption	Cluster III Adoption	Cluster IV Adoption	Cluster V Adoption	Cluster VI Adoption	Total Adoption
2030	35.1%	9.9%	6.8%	5.7%	3.9%	3.2%	239,919
2035	94.7%	57.1%	39.7%	12.7%	7.9%	6.2%	783,410
2040	99.8%	94.2%	86.8%	52.3%	7.9%	6.2%	1,170,563
2045	100%	99.5%	98.4%	97.2%	91.8%	8.5%	1,581,383
2050	100%	100%	99.8%	99.7%	98.6%	97.3%	1,837,753

8.2.3. Building Code Assumptions

Currently, the Company assumes the load required to heat is 5.04 W/sqft with a ASHP COP 2 is 2.52 W/SqFt as an average value. This yields, e.g. for the average residential building a unit load of 5kW for a 2000sq-ft home. However, this represents an average and can vary regionally, and can also be driven down over time through energy retrofit programs. At a high level, the following impacts can be determined for the overall building heating load as seen in Table 63 (assuming such envelope efficiency gains could be realized across all buildings, which is, especially for commercial buildings or high rises that incorporate a lot of glass into their façade not entirely feasible) for the year 2050 during the system wide peak hour of 8 – 9 am.

Table 63: Impacts on Peak Demand through changes in Building Peak Energy Demand

Assumed average peak building energy demand	Resulting ASHP electric peak demand (Cop of 2 assumed)	Metro Boston (MW)	Metro West (MW)	Southern (MW)	WMA (MW)
4 W/sq-ft	2 W/sq-ft	4465	4045	3042	1268
5 W/sq-ft	2.5 W/sq-ft	5582	5057	3803	1586
6 W/sq-ft	3 W/sq-ft	6698	6068	4563	1903

It is important to understand the impacts of such envelope improvements that could be enacted through building codes. On the flip side, however, it needs to also be remembered that such a change to a very old and very large existing building stock with a very low turnaround time is likely to be a very expensive and time-consuming undertaking.

8.2.4. Demand Response Scenarios – Impacts on Heating Demand

Demand response applications for electric heating are currently not considered by the Company as part of the forecasting analysis. While demand response of cooling loads has been very successful in summer, the winter peak has some fundamentally different characteristics that make demand response less applicable.

As noted in Section 8.2, 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. 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 are able to "coast" for the duration of the demand response 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 during the event (typical dispatch periods are 5-8pm), the air conditioners will 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.

For a winter event, conversely, the home's temperature is likely to drop below the minimum value specified by the customer well before the end of the event. For example, if a customer indicates that their minimum acceptable temperature is 65 F, during a winter Demand Response event (anticipated to occur on the coldest days of the year), the temperature in the customer's home may get to that threshold very fast, potentially within an hour. Given that the duration of the winter peak is projected to last multiple hours, the effect of the program-participating heat pumps all turning back on after 1-2 hours may be that the system peak simply shifts later rather than being meaningfully reduced. In a worst-case scenario, the peak could even be higher than if no event had been run at all, due to the manner in which heat pumps operate. ASHP systems are optimized to maintain a constant temperature in the conditioned space; if the temperature is temporarily set back, the system works harder, and runs much less efficiently, when it has to return the space to the original temperature setpoint. One potential way to mitigate the snapback associated with heat pumps is to stagger the start and stop times for all devices participating in events. This technique, known as firm load dispatch, helps to achieve a stable target load by coordinating duty cycles across the population of participating devices and is currently utilized for thermostats in the existing DR program. However, for an event on a very cold day where the heat pump was already operating at its design limit, it may be challenging for the building to re-gain temperature after the event, potentially leaving the customers' home colder than desired for several additional hours. This is likely to result in customer dissatisfaction and greater numbers of customers opting out from the program.

Although active demand response is a poor fit for electrified heat, the Company is actively researching the viability of winter demand response for other load types, in response to a request from the Office of Energy and Environmental Affairs. Especially hybrid heating solutions offer significant potential for electric demand response due to their back up fuel sources.

8.3. Transport: Electric Vehicle Assumptions and Forecasts

Electric Vehicles represent the second largest driver of a statewide decarbonization effort while posing a set of unique challenges to the Company, as vehicles, unlike heating applications, can impact the electric system far away from where the technology adoption happens. As a result, an EV has, in most cases, one charging port at home base, and then multiple options (at work, shopping, or on vacation), where charging ports are held ready. This effect will cause the EDCs to construct more capacity on the system than the name plate total of EVs in the territory. Figure 205 below shows the respective contribution of EVs to the system peak from each region. These numbers now include the LDV, as well as the MDV and HDV projected regional impacts.

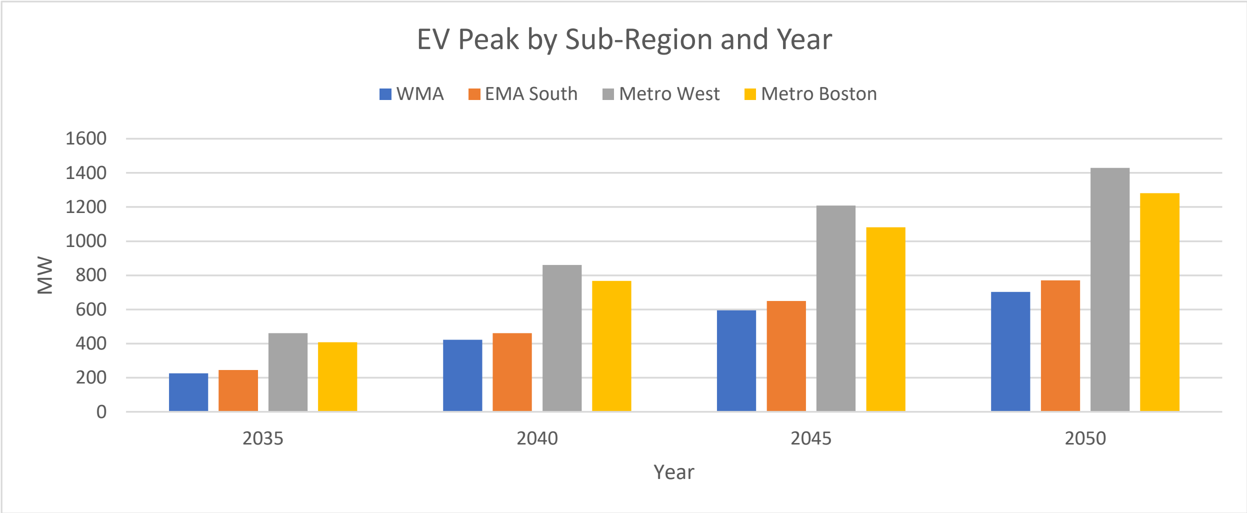


Figure 205: EV Contribution At Time Of Forecasted System Peak

It should be noted that the model underpinning this data assumes that vehicles have the opportunity to charge wherever they terminate a trip, be that at home, at work, shopping, or when on vacation. As an example, this allows the Metro Regions to absorb charging load in the early noon hours from inbound commuters. A lack of such an infrastructure would mean higher charging demand on the return commute and less of a demand in the morning hours for regions with inbound commute.

In addition, EV adoption, unlike heating electrification impacts, has no grace period for EDCs to adjust their system capacity as EVs contribute directly to summer peak conditions as the bulk of terminated trips overlap with the currently existing summer peak. Section 5 shows the expected near-term impacts of EVs in the next decade.

The Company also monitors the mobility of vehicles throughout the state to better understand how charging might have regionally different impacts and vary throughout the day. Figure 207 shows the statewide trip termination count (vehicle trips for light and medium duty vehicles) every 15 minutes. A trip is considered terminated when the vehicle stops for more than 5 min. The confidence bands show the range of possible arrival based on different seasons (Summer, Winter, Shoulder) and type days (workday, weekend, Friday, or holidays).

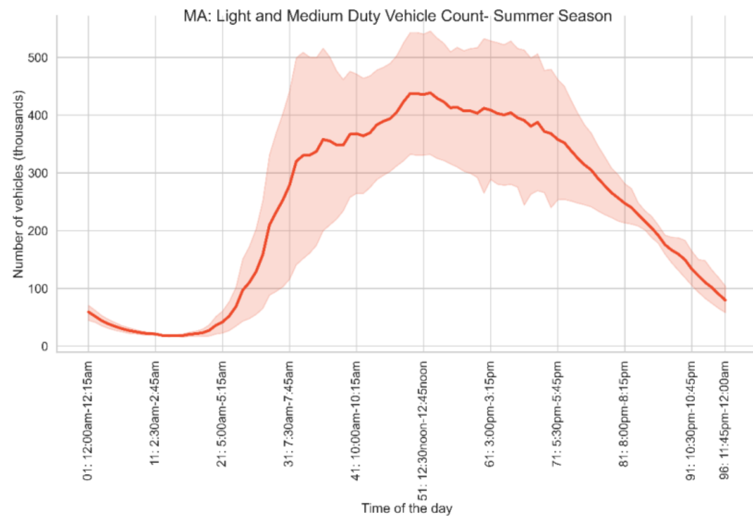


Figure 206: Statewide Vehicle Trip Termination every 15 min

8.3.1. Technology Assumptions

This Section will highlight the key technology assumptions the Company uses for modeling its EV impacts on the system. One key lesson, for the bulk substation capacity, is that the Company has learned that actual charging power of the charging stations is less important than the distances driven and number of vehicles.

8.3.1.1 EV Types based on Vehicle Weight Class

The Federal Highway Administration (FHWA) defines vehicle classification based on the Gross Vehicle Weight Rating (GVWR), which is the maximum vehicle weight, as specified by the manufacturer. The GVWR includes total vehicle weight plus fluids, passengers, and cargo. These classes, 1-8, are used consistently throughout the industry. The classes are shown in the below, including their correlation to the GVWR Categories that underpin the Company's analysis. Table 64 below shows these classifications as outlined by the FHWA.

Table 64: Vehicle Classifications by FHWA

Gross Vehicle Weight Rating- GVWR (lbs.)	Federal Highway Administration (FHWA)	
	Vehicle Class	GVWR Category
<6,000	Class 1: <6,000 lbs.	Light Duty <10,000 lbs.
10,000	Class 2: 6,001-10,000 lbs.	
14,000	Class 3: 10,001-14,000 lbs.	Medium Duty: 10,001-26,000 lbs.
16,000	Class 4: 14,001-16,000 lbs.	
19,500	Class 5: 16,001-19,500 lbs.	
26,000	Class 6: 19,501-26,000 lbs.	
33,000	Class 7: 26,001-33,000 lbs.	Heavy Duty >26,000 lbs.
>33,000	Class 8: >33,000 lbs.	

Based on the above discussion, there are three types of Electric Vehicles (EVs) in the U.S. Market based on the weight classification, including:

1. **Light Duty Vehicles (LDV):** This is the largest and most popular segment of the EV market. Mostly cars, vans, and pickup trucks with a GVWR of 10,000 lbs. or less are included in this category. LDV comprises of Class 1 and 2 of FHWA classifications. Ford Mustang Mach-E, F150 Lightning Pro Pickup truck, etc. are examples of the LDV. Typically, LDV battery sizes are up to 100kWh.
2. **Medium Duty Vehicle (MDV):** This type consists of 4 classes, Class 3-6 of the FHWA classifications making it the biggest vehicle segment among all. Most of the buses and utility vehicles weighing more than 10,000 lbs., but less than 26,000 lbs. are included in this category. Freightliner eM2 is one example of MDV. The MDV battery sizes typically range from 100 kWh to 300kWh.
3. **Heavy Duty Vehicle (HDV):** This type of vehicle covers Class 7 and 8 of the FHWA classification. Most long-haul trucks and heavy load carrying vehicles weighing over 26,000 lbs. are part of this segment. Freightliner e-Cascadia is one example of HDV. The battery sizes are typically over 300 kWh.

8.3.1.2 EV Types based on Fuel Technology

There are broadly four types of electric vehicles (EVs) in the U.S. Market.

1. Battery-powered Electric Vehicle (BEV)

This is the standard electric vehicle (EV) that is becoming more common in the market. They need to be plugged in and charged up to run. EVs stand out from most cars on the market due to the fact EVs lack Internal Combustion Engines (ICE). Instead of gasoline, these vehicles run solely on battery power. The fact EVs run only on battery power is what distinguishes them from hybrids that run on battery power with assistance from internal combustion engines. An example of a BEV is the Tesla Model 3. The states All Options Pathways assume a near complete stock turnover by 2050 to BEV with some residual FCEV vehicles on the Medium and Heavy-Duty Vehicle class.

2. Hybrid Electric Vehicle (HEV)

Hybrid Electric Vehicle (HEVs) run on both an internal combustion engine and an electric motor that uses energy stored in a battery. When it comes to Hybrid vs EV (HEV vs BEV), the difference is that HEV does not need to be plugged in to be charged (instead, the battery charges through regenerative braking). However, gasoline is needed to run the HEV. Regenerative braking stores the kinetic energy used to stop the car charging its battery and help the internal combustion engine accelerate the vehicle. Although they cannot run solely on electric power, they maximize fuel economy by shutting off the internal combustion engine during complete stops. The full hybrid has the battery power to make the car move using electricity alone, but usually only for short distances. An example of an HEV is the Toyota Prius.

3. Plug-in Hybrid Electric Vehicle (PHEV)

Plug in Hybrid Electric Vehicle (PHEVs) expand on the concept of the standard HEVs. They are like hybrid cars in that they can run off battery power but still have an internal combustion engine and take gasoline. However, they can run for longer distances and at higher speeds on electric power than a traditional hybrid car. When they run out of electric range, they can revert to hybrid performance and use gasoline to power themselves. These alternative fuel vehicles do need to be plugged in to charge. An example of a plug-in hybrid is the Toyota RAV4 Prime.

4. Fuel Cell Electric Vehicle (FCEV)

A Fuel Cell Electric Vehicle (FCEV) is an alternative fuel car less common than an EV (electric vehicle). FCEV runs on hydrogen. They are not common in the US (there are very few hydrogen stations to fill up). An example of an FCEV is the Toyota Mirai.

As discussed above, the two types of EVs that need to be plugged in to charge are BEVs (battery electric vehicles) (Battery Electric Vehicle) and PHEVs (Plug in Hybrid Electric Vehicle). Therefore, this document uses the term “EV” to refer to both BEVs and PHEVs, since these vehicles can be recharged from external sources and can operate with zero tailpipe emissions. This document focuses primarily on EVs and does not address HEVs and FCEVs unless otherwise noted.

8.3.1.3 EV Charging Levels

Electric vehicle (EV) chargers are characterized by levels. The levels describe how quickly a charger will recharge an EV’s battery. Theoretically, the higher the output from the charger, the faster the EV battery will recharge. However, charging speed is affected by many factors, including the charger manufacturer, condition, and age; air temperature; vehicle battery capacity; and vehicle age and condition. The standard charger levels are - Level 1 (L1), Level 2 (L2), and Level 3, or Direct Current Fast Charger (DCFC).

1. **Level 1 (L1) Charger:** L1 is the slowest type of charging equipment. L1 chargers plug directly into a standard 120V AC outlet supplying an average power output of 1.3 kW to 2.4 kW. This power output is dependent on the size of the EV battery. A full charge for an empty EV battery can take over 24 hours. L1 charging occurs primarily in residential settings. There are very few L1 chargers built for public use. A majority of L1 chargers come standard with the purchase of an EV.
2. **Level 2 (L2) Charger:** L2 chargers operate at 208 (commercial application) - 240 V (residential application) and output anywhere from 7 kW to 19 kW of AC power. An average EV can be fully charged in 10 hours or less. L2 is the most prevalent type of charger in the United States. L2 chargers have been deployed in many popular public locations, including parking garages, grocery stores, malls, and hotels. L2 chargers are popular at workspaces where employees can leave EVs charging for long durations. Additional installation and infrastructure are necessary for residential L2 ports.
3. **Level 3 or Direct Current Fast Charger (DCFC) Charger:** DCFCs (Direct Current Fast Chargers) are the fastest chargers available with a maximum output range of 50 - 350 kW. DCFCs are designed to fill a BEV battery to 80% in 20-60 minutes, and 100% in 60-90 minutes. The most PHEVs currently on the market do not work with fast chargers.

A tabular summary of different EV charging levels is shown below in Table 65.

Table 65: Common Charging Levels

Category	Level 1	Level 2	DCFC
Connector Type	J1772	J1772	Combined Charging System (CCS)/CHArge de Move (CHAdeMO)/NACS
Voltage	120 V AC	208-240 V AC	400-1000 V DC
Typical Power Output	1.3-2.4 kW	7-19 kW	50-350 kW
Cost Per Charge	$	$$	$$$
Speed	Slow	Medium	Fast
Primary Location	Residential	Residential, Public, Work	Public
0 - 100% charge	24 hrs+	< 10 hrs	20-90 minutes

When the Company models EV charging, its key interests lie in the impact of charging on bulk system equipment, as this equipment has the longest lead times to replacing, meaning long term forecasts are required. Research shows that bulk charging load is primarily impacted by the duration of the charging event relative to an average charging power.[221]

In order to understand the impact of EVs on bulk stations, it must be understood that a doubling of the average charging power would half the average charging duration (coincidence) and therefore the peak would remain the same. As an example, if 1000 vehicles randomly charge at level 2, it might be that due to their average charging duration of 1 hr., 500 charge at the same time, resulting in a peak of 11kW * 500 = 5500kW. If the same pool was charging at 55kW, so 5 times as much, their charging duration would drop to 12 min, which would also drop their charging coincidence to 100. The resulting bulk impact would therefore remain at 5500kW.

This can be explained in detail as follows:

Assuming a modeled time interval of N, which appears *n*-times during a day (example $\lambda_n = 5\text{ min}$) and two events, *Y* and *X*, at a length of λ_y and λ_x, respectively. If each event length is a multiple of λ_n, the relative event lengths to n are $\lambda_y{}'$ and $\lambda_x{}'$ (e.g., a 15 min event has $\lambda_y' = 3$). The chance χ_n of two events being registered simultaneously can now be determined as

$$\chi_n = \frac{\lambda_y' + \lambda_x{}' - 1}{n}$$

With the assumption that there are no other external impacts and entirely random occurrence of the charging events. This concludes that doubling event duration (e.g. through doubling distance driven at same charging power) would increase the chance of simultaneous charging.

Further, a total number of simultaneous charging vehicles χ_n^{Total} would be determined as

$$\chi_n^{\mathrm{Total}} \approx \chi_n * \text{number of vehicles}$$

And the respective system peak load impact P_{Peak} with P_{Mean} the mean charging power

$$P_{\mathrm{Peak}} = \chi_n^{\mathrm{Total}} * P_{\mathrm{Mean}}$$

And

$$P_{\mathrm{Peak}} = \chi_n * \text{number of vehicles} * P_{\mathrm{Mean}}$$

And

$$P_{\mathrm{Peak}} = \frac{\lambda_y' + \lambda_x{}' - 1}{n} * \text{number of vehicles} * P_{\mathrm{Mean}}$$

---

[221] "Impact and Chances of Electric Mobility for the German Low Voltage Distribution Grids." *Sierke Verlag*, www.sierke-verlag.de/produkt/impact-and-chances-of-electric-mobility-for-the-german-low-voltage-distribution-grids/

Yields for P_{Peak} with a simplification assuming $\lambda'_y + \lambda'_x + 1 = \lambda'_y + \lambda'_x$

$$P_{Peak} \approx \frac{\lambda'_y + \lambda_x{}'}{n} * \text{number of vehicles} * P_{Mean}$$

And replace λ' with kWh_{Mean} the mean energy needed to recharge

$$\lambda' \approx \frac{kWh_{Mean}}{P_{Mean}}$$

And insert for P_{Peak}

$$P_{Peak} \approx \frac{1}{n} * \frac{kWh_{Mean}}{P_{Mean}} * \text{number of vehicles} * P_{Mean}$$

Simplify and add a constant $C = \frac{1}{n}$ and cancel out P_{Mean}

$$P_{Peak} \approx C * kWh_{Mean} * \text{number of vehicles}$$

As a result, the peak charging power needed at a bulk substation level for a larger set of vehicles is only impacted by the mean energy required and the number of vehicles charging.

For this purpose, when the Company models its EV impacts on bulk systems (outside of locational charging depots) technology assumptions around battery size or charging power do not play into the evaluation. This has the benefit of making the assessments technology independent. The number of vehicles as well as the mean charging requirement are solely based on the mobility data the company utilizes and reflect actuals, not assumptions.

8.3.1.4 EV Charging Load Profile Modeling

The company uses two different methods to model the EV charging load profiles at the zip code and bulk substation level. The first method uses purchased vehicle mobility data and the second one utilizes the on-board telematics data. These methods are described as follows,

1. **Vehicle mobility data:** Eversource models the EV charging load profile at the zip code and bulk substation level to electrify all three categories LDV, MDV, and HDV, separately using the combination of Massachusetts' 2050 decarbonization roadmap and purchased vehicle mobility data. Vehicles charge upon trip termination with the charging duration based on previous trip length. In other words it is an 'Arrive-and-Charge' model with no consideration for utility or 3rd party charge management. It assumes sufficient charging infrastructure, especially on site and a 100% conversion of ICE/Alternate Fuel (AF) vehicles to EV. This is discussed in Section 5.1.2.6.
2. **Vehicle On-board telematics data:** Medium and heavy-duty EVs use two primary charging models: depot charging and on-route charging. Fleets with medium and heavy-

duty EVs often opt for Level 2 chargers (up to 19kW) for overnight charging at their depots. Fleets with larger vehicles that go longer distances may require DC fast charging at their depots as well as along the routes traveled by their vehicles. As these are often MW level systems, Eversource tracks these charging infrastructures as a spot/step load as described in the Section 5 Intro. The company is also actively collaborating with medium and heavy-duty EV Original Equipment Manufacturers (OEM) to collect the fleets' on-board telematics data. The vehicle telematics data contains the latitude and longitude of the charging sites, daily count of MDV and HDVs, average stop time and average daily miles driven. Based on these attributes, Eversource derived the consumption in kWh and demand in kW assuming a range of 2kWh/mile. This gives an insight into the on-route average charging demand of these big vehicles. However, it lacks the temporal dimension to capture the peak demand and peak time. Using the telematics data and the company's bulk substation GIS mapping, the company projected the EV charging step loads to the nearest bulk substation.

In future, the company plans to use the actual charging pattern from the Electric Vehicle Supply Equipment (EVSE) to model the charging load demand. Medium and heavy-duty EVs use two primary charging models: depot charging and on-route charging. Fleets with medium and heavy-duty EVs often opt for Level 2 chargers (up to 19kW) for overnight charging at their depots. Fleets with larger vehicles that go longer distances may require DC fast charging at their depots as well as along the routes traveled by their vehicles. As these are often MW level systems, Eversource tracks these charging infrastructures as a spot/step load as described in Section 5.

8.3.1.5 EV Depot and Fleet Charging

The reason for the Company tracking depot charging application as step loads for the 10-year forecast lies in their relatively binary adoption by location, the size of the adoption, and the uncertainty of the location, even with existing depots as the 10 year forecast is conducted at a station level. For the 2035-2050 long range assessment, the Company does include MDV and HDV in its model as no station-by-station assessment is conducted and only regional data generated.

a) Due to their size, large charging depots can single handedly cause significant system upgrades to occur. Consequently, including all known depots in the territory would result in essentially every station requiring upgrades. This in turn would not allow for any realistic prioritization of projects. Therefore, the Company tracks these items through step loads to receive customer input on priorities. Locations that have not shown any interest and are therefore not directly tracked in step load are not considered.
b) Tracking depots in step loads also protects rate payers for investments that might not be needed as it is not a given that all depots will electrify as some might choose to work with

biofuels or hydrogen technology. Pre-emptively including all depots therefore has the chance of triggering more need-based upgrades than might actually be required.

c) The Company has found that operators of depots when electrifying often consider a new location as part of the rebuild. This brings a challenge, that depots might move out of a station territory, which makes it hard to understand exactly where they might occur without receiving a direct request from the developer.

The Company is however engaging with OEMs to understand where such depots are located. Figure 208 shows the MDV and HDV charging depot across Eversource's service territory and will adjust its step loads once a firm commitment of capacity needs are submitted, and locations are secure. In future, the company plans to use the actual charging pattern from the Electric Vehicle Supply Equipment (EVSE)/vehicle charging profile history to model the charging load demand as a time-series model.

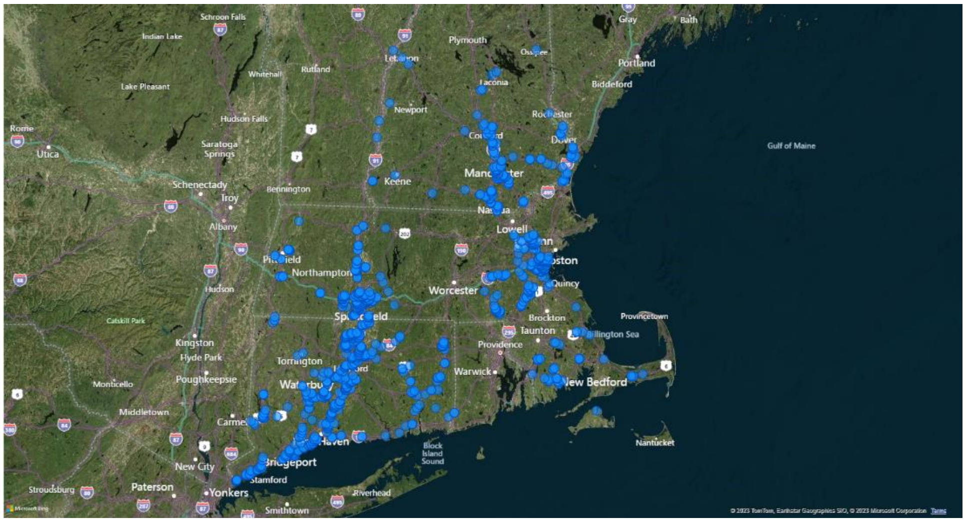


Figure 207: Known MDV and HDV depot locations

<u>Fleet Electrification- Challenges</u>

Massachusetts adopted Advanced Clean Trucks (ACT) in 2021 and Advanced Clean Cars II (ACC II) rules in late 2022. Advanced Clean Trucks (ACT) has an overall goal to develop a self-sustaining zero-emission truck market by requiring vehicle manufacturers to sell zero emission medium-heavy duty vehicles (MHDVs) as an increasing percentage of their annual sales through 2035, ranging from 40-75% of sales depending on vehicle class. On the other hand, ACC II requires auto manufacturers to ensure that every new light-duty car sold in the state is a zero-emission vehicle (ZEV) by 2035. On top of that, Massachusetts is aggressively planning to electrify the buses and ferries to reach the net-zero goal by 2050.

Due to the ACT rule, medium and heavy-duty EVs are taking the center stage along with the light duty EV segment. However, the medium and heavy-duty segment has traditionally been challenging to electrify because of the following reasons:

1. **High energy requirements:** MDV and HDV are big and require more energy to run than LDV. Therefore, the energy requirement is high for both of these two segments. For example, using a class 7 or class 8 vehicle may have a typical battery pack of 315 kWh to 438 kWh. Using a L1 charger of 2kW will take at least a week to fully charge the battery which is completely unacceptable for day-to-day operation. Using an L2 charger of 7.2 kW will require at least 48 hours to fully charge the battery, which might be acceptable for a shorter operational distance. That is why MDV and HDV EVs require separate infrastructure investments from light-duty EVs prioritizing DCFC and Megawatt (MW) level chargers. Currently, in the US, the supporting charging infrastructure is not in place.

2. **Lack of standards:** There is still a lack of consensus on standards for the megawatt (MW) charging systems medium and heavy-duty EVs require. DCFC chargers (350kW) are mature but expensive, and successful fleet electrification is heavily dependent on these, but even this won't be enough to tackle the charging need to tackle large transportation electrification demand.

3. **Cost:** The upfront cost of MHDVs is still higher than the cost of gasoline vehicles, which can be a barrier for businesses that are looking to electrify their fleets. This has, however, continued to become equalized by significantly lower running costs.

As the challenges listed above are overcome, more and more fleets will electrify in the next decade and the Company is working very closely with the operators to ensure that sufficient visibility is available to ensure capacity upgrades are completed as needed.

One such fleet operator is the MBTA bus services that the Company, together with National Grid, depending on the depot location, is working hand in hand with. Understanding early and having very clear timelines and commitments communicated by the MBTA allows the Company to Account for the additional charging need in its forecast.

The Company further closely works with State entities to make the roll out of DC infrastructure along main travel corridors as smooth as possible.

8.3.2. Adoption Propensity Assumptions

By 2050 the state's objectives have almost all vehicles in operation transition to an electrified version (based on the 2050 decarbonization roadmap "All Options" Pathway.) Therefore, the Company's forecast for EV adoption assumes all vehicles within Massachusetts will have adapted to an EV by 2050. Eversource utilizes the 2050 decarbonization roadmap, which is a High Electrification decarbonization pathway with the goal of electrification of more than 90% of vehicles running on fossil fuel. Through the use of the High Electrification pathway, the

Company adopts their yearly EV adoption goals assuming each year is what's needed to see full electrification by 2050.

However, the challenge for the Company with this data is that it does not show, station by station, when and where such a transition will happen. This, however, is critical for the Company to understand for the Company to properly prioritize its capital plans. Therefore, the Company introduced an Adoption Propensity Model. Adoption propensity models are used to determine one's relative likelihood of adoption. In the case of electric vehicles, an individual's likelihood of adopting an electric vehicle is determined relative to their variables, or factors believed to drive electric vehicle adoption.

When applying Adoption Propensity Models to the heat pumps, the Company took the baseline approach that forecasted adoption of electric vehicles is type agnostic. Therefore, the number of electric vehicles predicted year-by-year is considered as a number representing all electric vehicles, not a specific vehicle type. To develop a methodology for electric vehicle adoption, the Company merged customer data and information the Company procures to support its targeted Energy Efficiency program role out) along with customer specific Eversource data. This allowed the Company to create a dataset to determine which individuals use different heating types, and what their socioeconomic factors are that might impact their likelihood to adopt. In conjunction with statistical tests, the Company utilized individuals with business expertise to determine which of the parameters and metrics that the Company has on its customer are key indicators of heating adoption. This resulted in a total of 6 that the Company qualified as the key socio-economic factors that impact the likelihood of electric heating adoption. The identified factors are, in order of their relative impact on the adoption propensity and are based on current incentive designs:

1. **High Income*:*** an individual who falls between the 75th and 99th percentile of income in MA
2. **Single Family:** an individual who lives in a single-family home
3. **High Density Area:** an individual who lives in an area with a population density above the
4. **Behavioral Green:** an individual who thinks and acts green, holds negative attitudes toward products that pollute, incorporate green practices on a regular basis
5. **Has Children:** an individual who has at least one child
6. **Younger Age:** an individual between the age of 18 and 43.

Since this data has been merged with Eversource customer data, the Company assumes that the number of individuals falling into these categories of drivers also represents the totality of the state of Massachusetts. It can be determined from the figure below that only 14.2% of individuals are between the ages of 18 and 43. Roughly 38% of individuals have at least one child, 50% live in high density areas, 12% are considered behavioral green, 57% live in a single-family household, and 25% are considered high income.

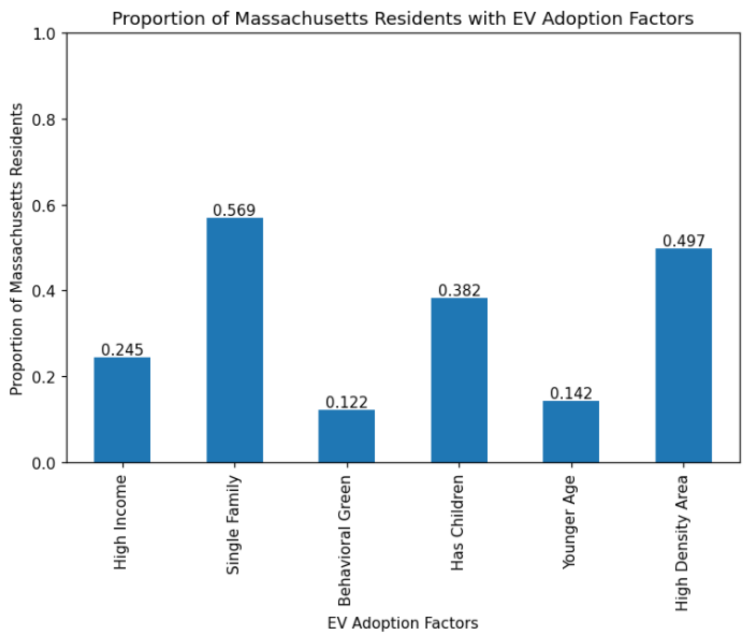


Figure 208: The proportion of Massachusetts residents who fall into each of the EV adoption driver categories

The number representing its ability to drive electric vehicle adoption can also be viewed as a ranking, where living in a single-family home is viewed as the factor with the greatest impact on likelihood to adopt heat pumps and living in a newer building is the smallest impact.

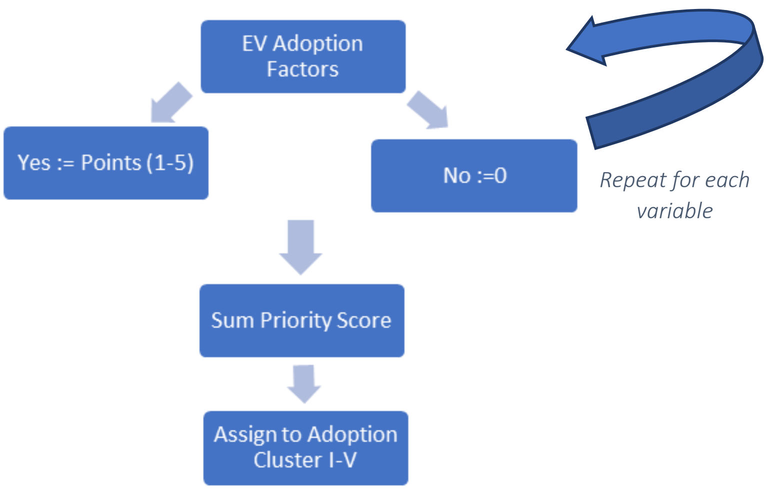


Figure 209: Electric Vehicle Adoption Propensity Model Process

Table 66: Year Each Adoption Cluster Met Corresponding Adoption Percentage

Customer Example	High Income	Single Family Home	High Density Area	Behavioral Green	Has Children	Younger Age	Priority Score
John Doe	6	5	4	3	2	1	21
Jane Doe	6	5	4	3	2	0	20
John Smith	6	5	4	3	0	0	18
Jane Smith	6	5	4	0	0	0	15

Individual level data visibility enables the Company to see if an individual falls into one of these categories or not. If an individual does, they also receive the ranking number, where the higher the ranking, the greater the driver. From there, the Company summed these individuals' scores to determine which individuals had the highest and lowest scores. The Company refers to this score as a priority score. All combinations of these scores were used to determine how likely an individual is to adopt heat pumps. The Company developed adoption clusters depending on the conditions surrounding the data. These clusters were ordered depending on when each cluster is assumed to adopt. Cluster I is assumed to be the fastest adopting group, whereas Cluster VI is assumed to be the slowest adopting group. Therefore, one can assume that the individuals from each cluster will adopt differently with respect to time.

The adoption clusters in order of adoption are Cluster I, Cluster II, Cluster III, Cluster IV, and Cluster V. For Cluster I, the Company considers these individuals to be the first to adopt and will have a priority score between 14 and 21. Cluster II consists of individuals who have a priority score between 10 and 13. Cluster III are those with a priority score between 7 and 9. Cluster IV are individuals are those with a priority score between 4 and 6. Lastly, Cluster V individuals only have a priority score between 0 and 3. From the Figure 221 below, the proportion of individuals from the state of Massachusetts in each adoption cluster. Cluster IV has the highest number of individuals at 32%, Cluster III at 20%, Cluster II at 20%, 19% for Cluster V, and 10% for Cluster I.

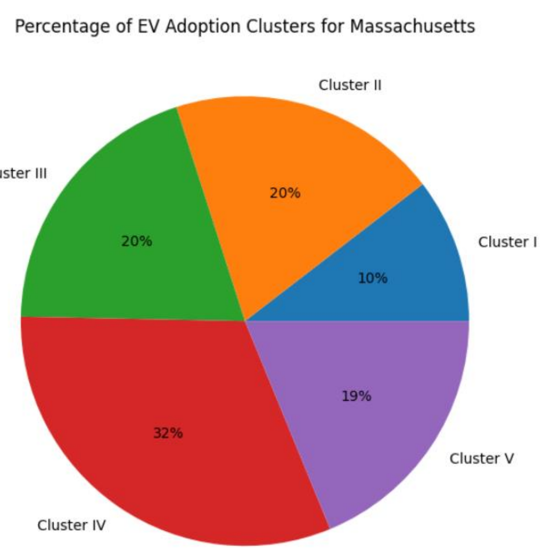


Figure 210: Percentage of Eastern Massachusetts (EMA) individuals who fall into each Electric Vehicle (EV) adoption cluster.

The following Graphs in Figure 212 a-d show the customer cluster split by each Sub-Region for the electric vehicle adoption. There are visible differences between these graphs, especially with the innovators and early adopters with the Metro West Sub-Region leading the charge.

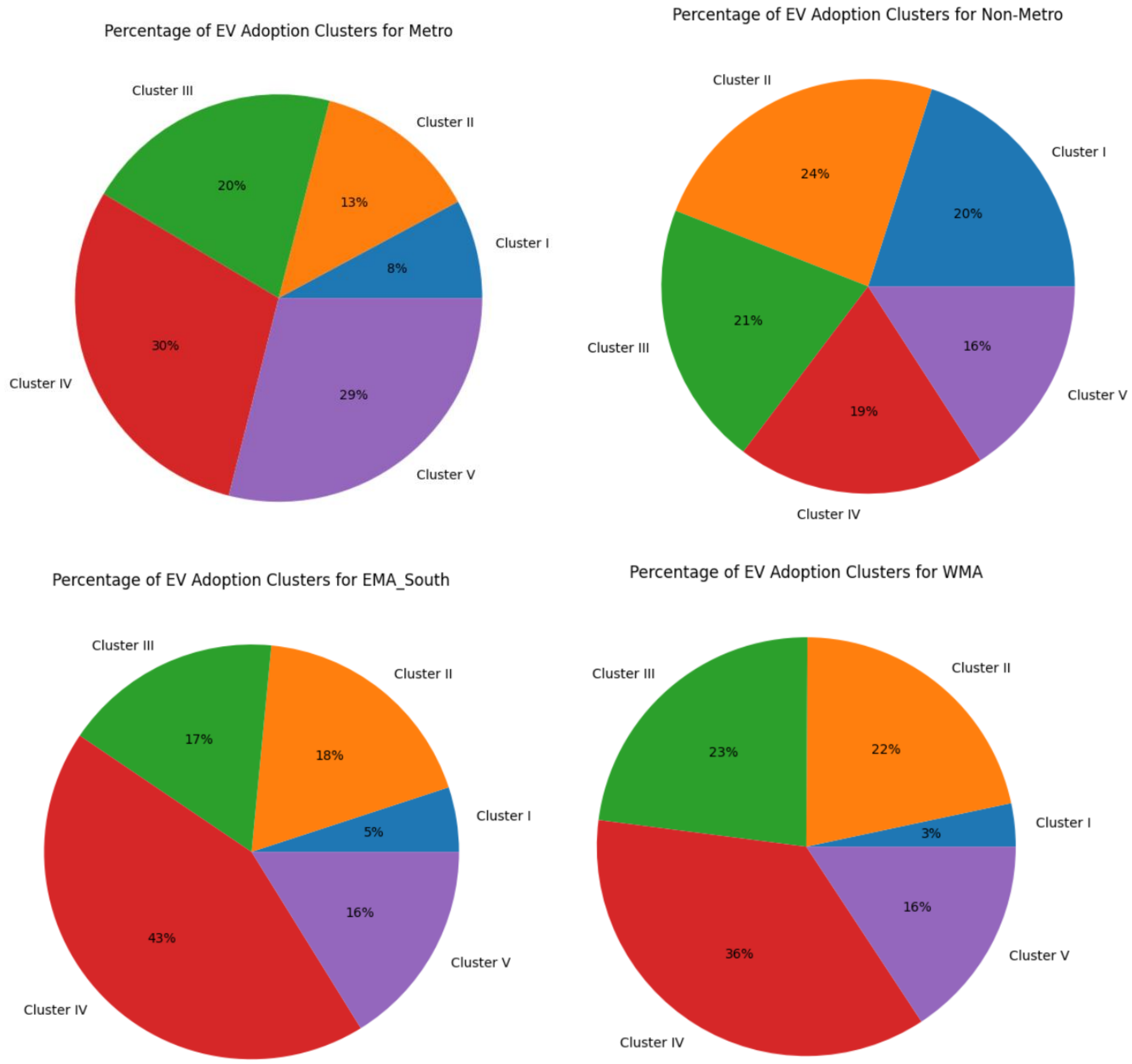


Figure 211: EV Clusters by Sub-Region a) Metro b) Metro West c) Southern, and d) WMA

As a part of the assumptions, the Company believes that individuals who fall into each cluster will adopt differently with respect to time. Therefore, individuals from one cluster may adopt faster than individuals from another cluster. Under this assumption, the Company developed a methodology that assumes individuals from all clusters are adapting at each time point, but some clusters are adopting faster than others. Adoptions from each group are believed to continue until 2050 with nearly 100% adoption from each cluster. This methodology begins by fitting each cluster to a logarithmic growth curve. It can be assumed the logarithmic growth rate is greatest for innovators, and smallest for laggards. These growth curves can be viewed as a probability cumulative function since the highest number reached is 1, representing 100% adoption. From the Figure 223 below, there is a sample from these cumulative density functions with time. The Company assumes that priority of sampling should be given to the adoption cluster with the highest growth rate.

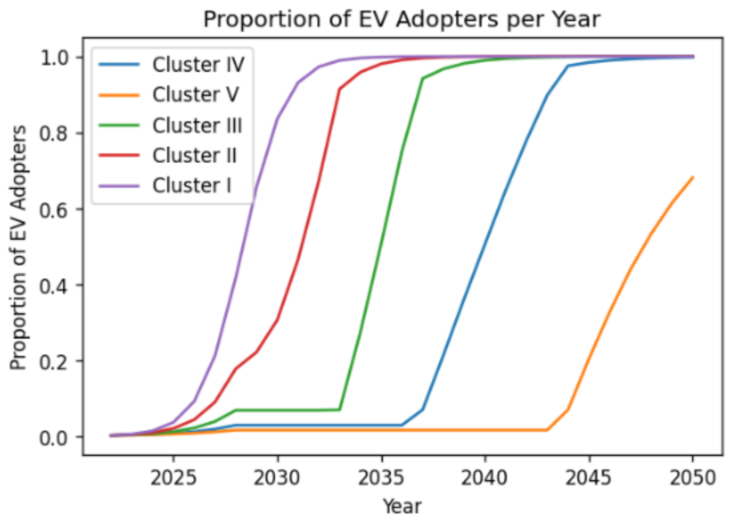


Figure 212: The Proportion of Adopters for Each Adoption Type Relative to Time.

The following Table 67 shows, for each cluster, the year they reach a certain adoption level. Highlighted the 95% adoption level.

Table 67: Year of Cluster Adoption

Adoption Percentage	Cluster I Year	Cluster II Year	Cluster III Year	Cluster IV Year	Cluster V Year
40%	2028	2031	2035	2040	2047
60%	2029	2032	2036	2041	2049
80%	2030	2033	2037	2043	N/A
90%	2031	2033	2037	2044	N/A
95%	2032	2034	2038	2044	N/A

Table 68: Adoption Per Cluster Per Year

Year	Cluster I Adoption	Cluster II Adoption	Cluster III Adoption	Cluster IV Adoption	Cluster V Adoption	Total Adoption
2030	83.6%	30.6%	6.8%	2.9%	1.6%	633,520
2035	99.9%	98.1%	50.6%	2.9%	1.6%	1,145,901
2040	100%	100%	99%	50.6%	1.6%	1,500,113
2045	100%	100%	99.9%	98.4%	20.3%	1,703,044
2050	100%	100%	100%	99.8%	68.1%	1,792,756

8.3.3. Mileage, and Time of Day Assumptions

Mileage driven by vehicles, together with their average consumption, is one of the key contributing factors to EV charging impact on the system as it directly correlates to charging durations with all else being equal. The Company models charging behavior by station based on the traffic pattern analysis, which is based on the mobility data outlined in Chapter 8.3.1. This results in different profiles by station, as some stations see more early morning traffic (inbound commuter heavy), and others receive more afternoon/evening traffic (outbound commuter heavy). In addition, there are stations, such as in the Cape region, that due to their seasonality (vacation hot spots), have entirely different vehicle utilization profiles.

8.3.3.1 Average Miles Driven

Table 69 below highlights, by sub-region, the Company's underlying assumptions of miles driven for each sub-region; the higher the mean distance, the more energy needs to be re-charged per charging cycle, the longer the charging duration, and the more simultaneous charging cycles occur putting stress on the system

Table 69: Mean Distance Driven and Peak Arrival Times by Sub-Region

	EMA North Metro	EMA North Metro West	EMA South	WMA
Mean Distance LDV (mi)	10.50	12.73	13.52	13.28
Peak Arrival Time LDV	5:45PM- 6:00PM	5:45PM- 6:00PM	5:15PM- 5:30PM	5:15PM- 5:30PM
Mean Distance MDV (mi)	11.78	18.44	22.85	25.20
Peak Arrival Time MDV	9:15AM- 9:30AM	8:15AM- 8:30AM	8:00AM- 8:15AM	12:00PM-12:15PM
Mean Distance HDV (mi)	35.44	47.40	51.52	48.26
Peak Arrival Time HDV	10:45AM- 11:00AM	10:30AM- 10:45AM	12:15PM- 12:30PM	7:45PM- 8:00PM

The mean distance driven also varies strongly over time as shown in the following Figures 214 to 219, which depicts the mean distance driven, over time, for the peak arrival in weekday (M-Th) and summer season (Jun-Aug). Since the underlying data is based on recorded trips, time intervals with a low recorded trip count are subject to high volatility in mean distance driven.

Figure 214 shows the mean distance driven for LDVs and highlights a couple of interesting observations. For the Metro Region, there is a significant spike in the early mornings indicating the arrival of all the long-distance commuters who aim to get into the city as early as possible. Metro, on the other hand does not have a high evening commute distance for trips terminating in the region, as people from the Metro Boston Sub-Region appear to not be driving long distances for commutes. Other regions in turn show an uptake of evening commute distances, presumably returning from the Metro – Region. This has impacts on the ability of charge management to effectuate change discussed in Section 9.1.2.

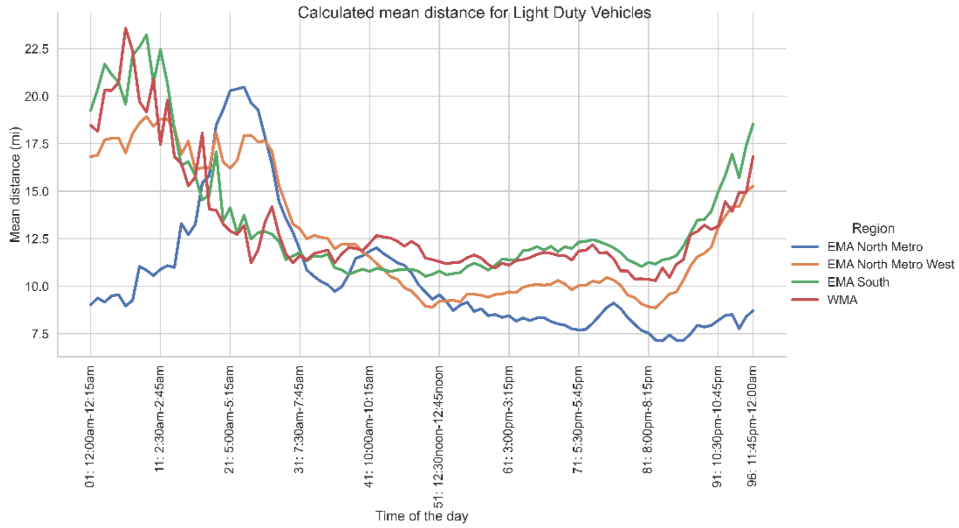


Figure 213: Mean Distance Traveled per LDV terminating a trip by region

For MDV's the travel profiles look very similar across the territory driven by delivery fleets which do not fully terminate a trip (more than 5 min standing time) and return to home base in the evening with the accumulated trip of the day. This shows the fleet behavior and the corresponding expected charging behavior which will focus very much on the evening and night time hours.

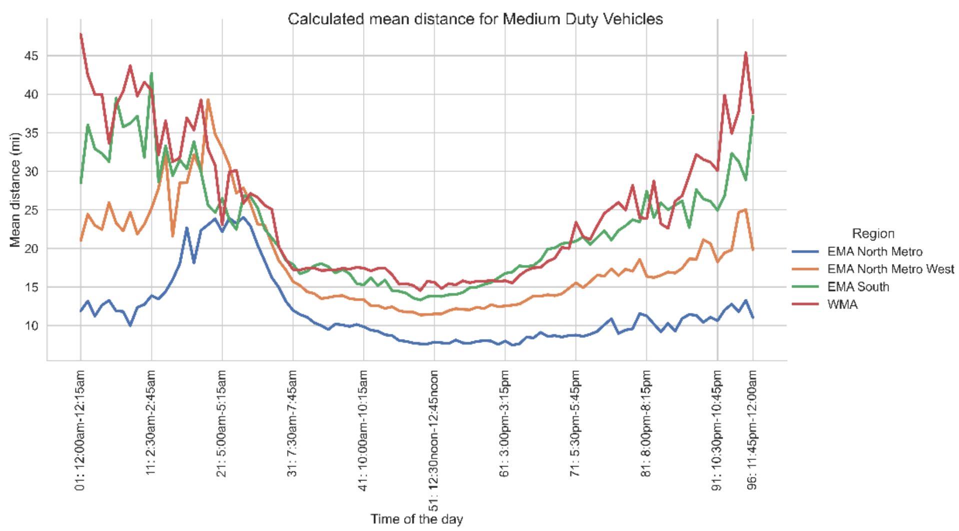


Figure 214: Mean Distance Traveled per MDV terminating a trip by region

For HDV the profile again looks similar throughout the day, but has a deviation in the evening where a substantial and sudden drop in distance driven occurs at 8pm. This is a phenomena the Company has not definitively determined the reason for. One possible explanation is

Massachusetts regulations that require certain trucks to be off the road by 8pm.[222] These regulations may also explain the jumps in arrival seen in Section 8.3.3.2.

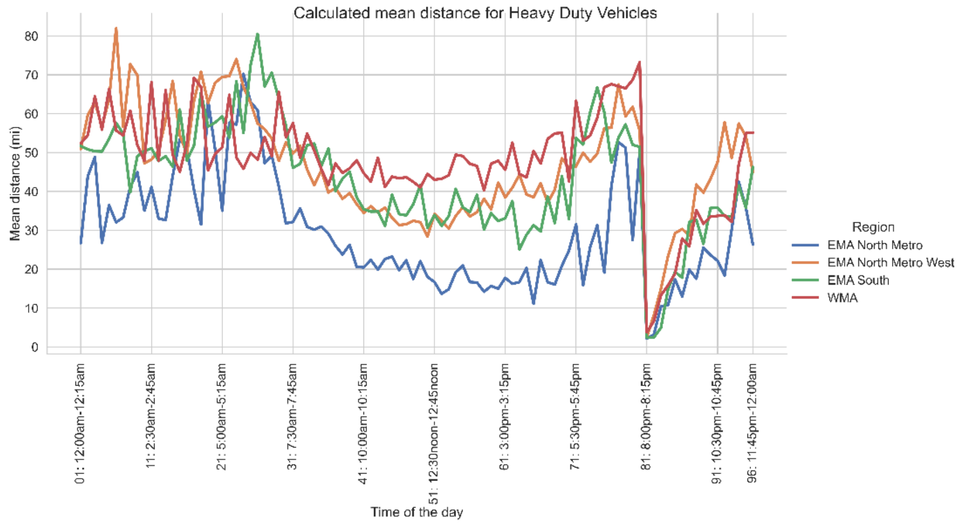


Figure 215: Mean Distance Traveled per HDV terminating a trip by region

The Company also tracks the distribution of distances driven to help inform, in combination with the dwell time data, the possibility of charge management. The following 3 Figures show the histograms of the mileage driven for vehicles arriving during the peak vehicle trip termination hours in each sub-region by vehicle class.

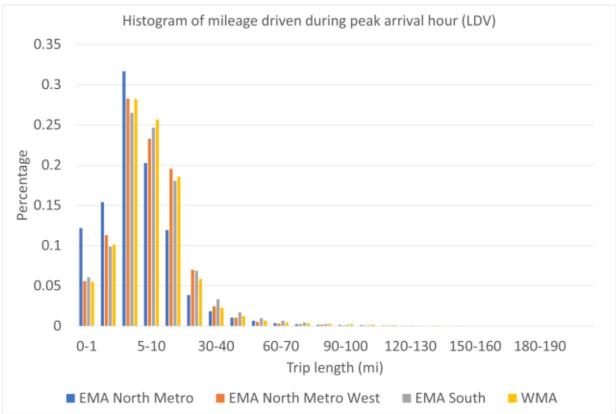


Figure 216: Distribution of Mileage driven during peak hour vs Trip Length for LDV

---

[222] "State Restricted Travel." *Nationwide Express Services*, nationwideexpressservices.weebly.com/uploads/2/9/4/0/2940251/state_restricted_travel_new.pdf

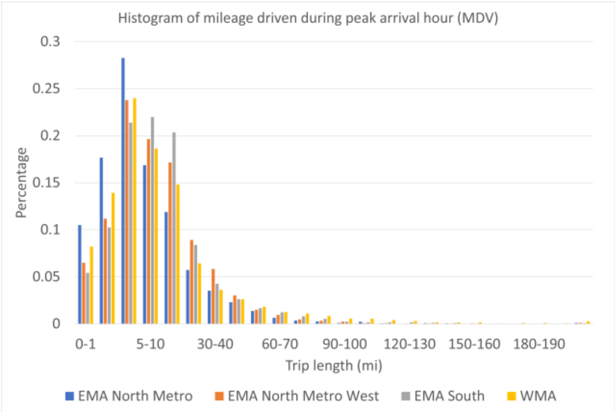


Figure 217: Distribution of Mileage driven during peak hour vs Trip Length for MDV

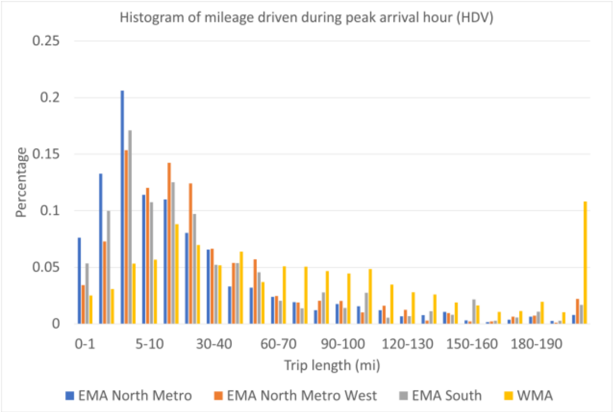


Figure 218: Distribution of Mileage driven during peak hour vs Trip Length for HDV

8.3.3.2 Time of Day Assumptions

The Company utilizes mobility data as outlined in Section 8.3.1 to understand, by station, when the peak impact of EV charging will occur. In order to achieve this, the mobility data is evaluated at a station level. To account for day-to-day variations, as well as seasonal shifts in driving behavior, the vehicle mobility data has day type and seasonal attributes. So, the Company has the capability to add sensitivity analysis accounting for seasonal variation and workday/weekend scenarios in the projected EV load profile. Four seasons are considered for EV load profile modeling:

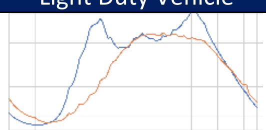
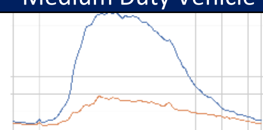
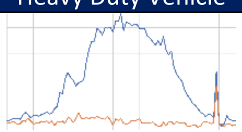
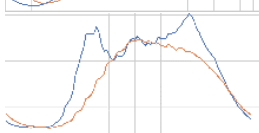
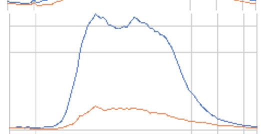
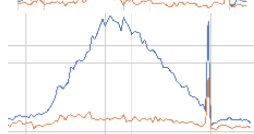
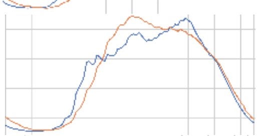
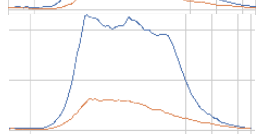
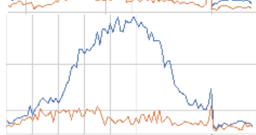
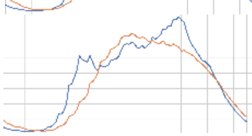
- Summer (Jun-Aug)
- Spring (Mar-May)
- Winter (Nov-Feb) and
- Fall (Sep-Oct)

Four types of days are modeled:

- Weekday (Mon-Thu)
- Friday (F)
- Weekend (Sat-Sun) and
- Holidays (National Holidays)

As long as the Company is expecting the overall system peak to occur in the summer peak, summer season weekdays (Mon-Thu), EV data is utilized to estimate the coincident peak unless otherwise stated. These days show the highest overall vehicular traffic (excluding Friday) and the highest confidence in the data. The following graphs show the number of vehicles arriving for weekdays and weekends for each vehicle class and region, during the summer season. Clearly visible, the different travel patterns between weekdays and weekends, but also, between the regions, the number of vehicles, and their arrival times vary. It should be noted that these represent totals over the respective sub-regions and within each sub-region, each station in itself, and even every zip code can have a different profile. The Company will be modeling each station individually.

Table 70: Arrival Profiles by vehicle type and sub-region

	Light Duty Vehicle	Medium Duty Vehicle	Heavy Duty Vehicle
EMA North Metro			
EMA North Metro West			
EMA South			
WMA			

8.3.3.3 Dwell Time Data

Another data set the Company utilizes to understand how charging might occur, and how charge management might be implemented, is what is termed "dwell time" data. Dwell time data shows how long vehicles tend to stay at a location where they terminated a trip. Very short dwell times, such as a car stopped at the grocery store, do not present an opportunity for charge management. Very long dwell times, such as cars plugged in at home overnight, are ideal for charge management, as there is greater flexibility in when charging can occur, allowing the EDC to direct the car to charge at times that are most beneficial to the grid. Moderate dwell times must be studied carefully; some of these vehicles may be available for charge management, but others may have less flexibility. For example, if vehicles arrive with a very high mean distance driven while having only a moderate dwell time, such as people charging while they are at work after commuting, charge management applicability would be limited, as the car needs to regain a substantial amount of charge over a shorter time. The following graphs show the mean dwell time for a summer weekday by region, and vehicle class, clearly highlighting how, depending on the time of day, and the vehicle type, the dwell duration changes. The value shown represents the mean dwell time for all vehicles at a specific time. Specific effects can be seen in the two metro regions, where the dwell times have a noon hump from the vehicles arriving as part of the morning commute. Similarly, every region shows the nighttime hump of vehicles standing.

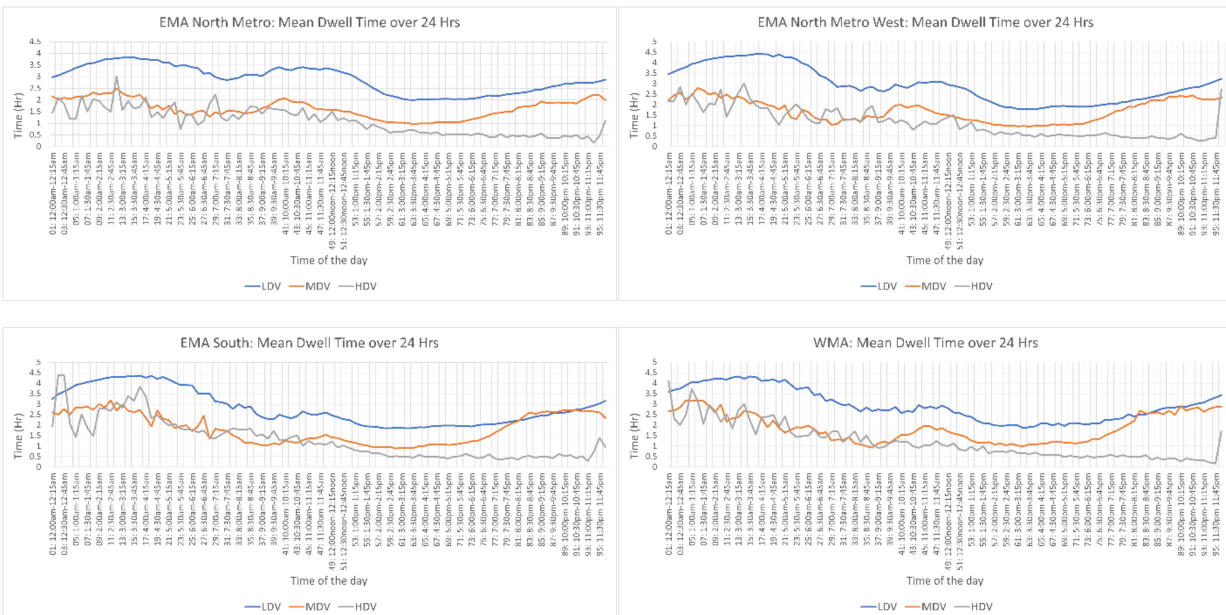


Figure 219: Dwell times by vehicle type and region

8.3.4. Managed charging scenarios – impacts on EV demand

Well-designed managed charging can reduce the contribution of EV charging to overall system peaks, helping minimize grid infrastructure costs. However, since the Company currently does not have a managed charging program, the forecast modeling assumed no change to EV load profiles from charge management. Eversource is actively working with regulators and stakeholders to develop a managed charging program for Massachusetts electric vehicle owners (see Section 9.1.2) and future iterations of the forecast will reflect those programmatic designs, if/as approved by the Department.

8.4. DER: PV/ESS – State incentive driven assumptions and forecasts

Distributed solar and storage play a key role in the Commonwealth's transition to a decarbonized future with the overall state objective being 16.2 GW of ground mounted, and 7.0 GW of rooftop solar by 2050, as well as 2.9 GW of energy storage to assist peak shaving efforts (2050 MA Decarbonization Roadmap). The following Figure 220 shows the Solar Roadmap laid out under the All Options Option mapped against the Current Installed Solar (dark blue) and the Current In-Queue (light blue). Noticeably, the ES territories are already ahead of the roadmap by more than twice the projected amount for Installed, and more than 4 times if In Queue is included.

The hosting capacity values shown are aggregated values of the bulk station hosting capacities. This means e.g. that the Cape CIP D.P.U. 22-55 does not add additional bulk station hosting capacity as no substations are upgraded. The data also excludes stations that have not and will not see any large-scale solar development, such as Metro Boston stations, or stations servicing load centers in Springfield. They are however included with 2 MW of hosting capacity each attributed for potential further rooftop solar.

The red lines show the various build out stages of the system wide hosting capacity at bulk stations not representing any distribution constraints. A result of this that e.g., stations that are part of a group study but receive no upgrades do not contribute to increases.

As it is not possible to do a detailed aggregation of the available hosting capacity due to its iterative nature and distribution constraints, this serves as an indicative proxy and it should be assumed that actual currently available hosting capacity is lower, while enabled capacity by CIPs is higher.

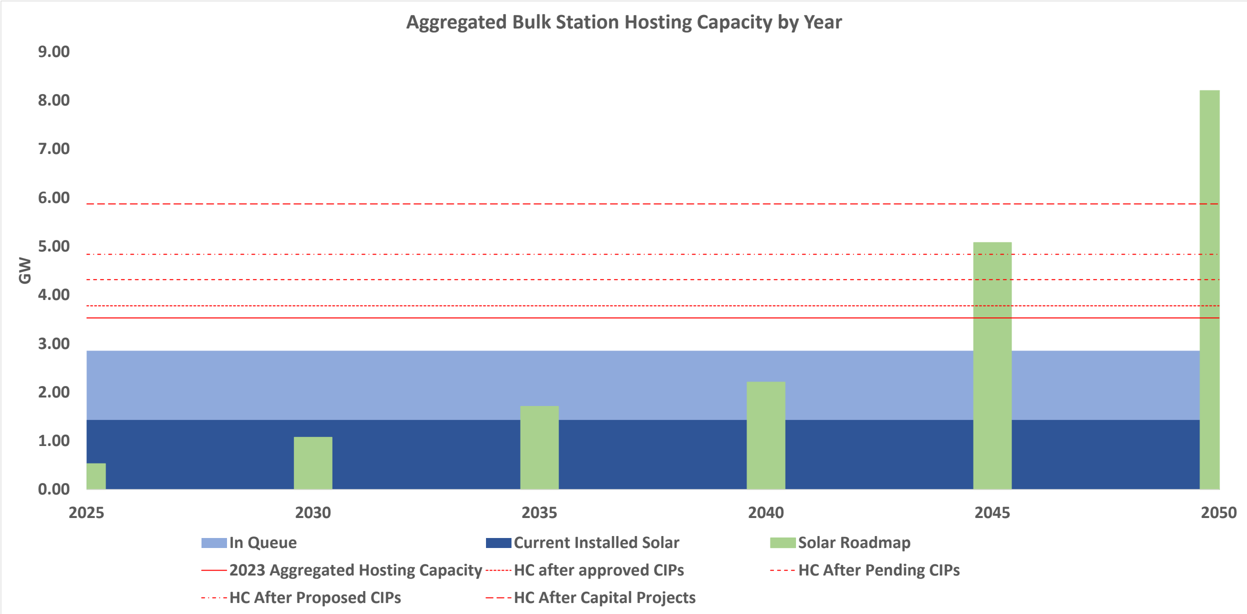


Figure 220: Projected Solar in Eversource MA Territory Driven by State Objectives

The challenge with the projected solar adoption is that, as outlined in Section 4, solar will drive a very regional build out with limited to now overlay between solar and load.

The current forecast as presented in Figure 220 assumes the approved CIP (Marion Fairhaven) as well as all remaining 5 CIPs pending approval will be built. The model then ranks the economic viability of every property in the territory and starts build out across these properties (see Section 5 ground mounted solar methodology). Once a certain station is saturated, any next development in that station would be tagged with upgrade costs making parcels in the region less viable. In the first phase, the model will fill out all remaining hosting capacity (considering both substation and distribution circuit constraints) for regular and CIP stations in the cheap land areas (WMA and Southern Sub-Region). Next, regions where no station upgrades are required but land is expensive move into focus (Metro – West), a trend the Company is already observing now as CIP holds are in effect in other areas. Once all accessible substations are saturated and upgrades would have to be paid for everywhere, the model focuses build out where land is the cheapest (WMA) as shown in Figure 221 below.

It is important to understand that this forecast represents a scenario with given parameters. Once those parameters change, e.g., through more CIP approvals, the forecast will adopt. Given that the key driver of the forecast is, together with property cost, the availability of hosting capacity, it provides a certain opportunity to directing DER by enabling hosting capacity. The Company expects that once the pending CIPs are approved in the EMA South Sub-Region that a major shift of development will take place.

Table 71: Peak Components by Sub-Region

Component		WMA (MW)	EMA-South (MW	EMA-North Metro West (MW)	EMA-North Metro (MW)
Current Solar Hosting Capacity	108	248	313	42[223]	
Hosting Capacity reflective of ESMP 10 Year Plan	421	1170	864	56	
Cumulative Forecasted Change	4,700	2,000	1,300	100	

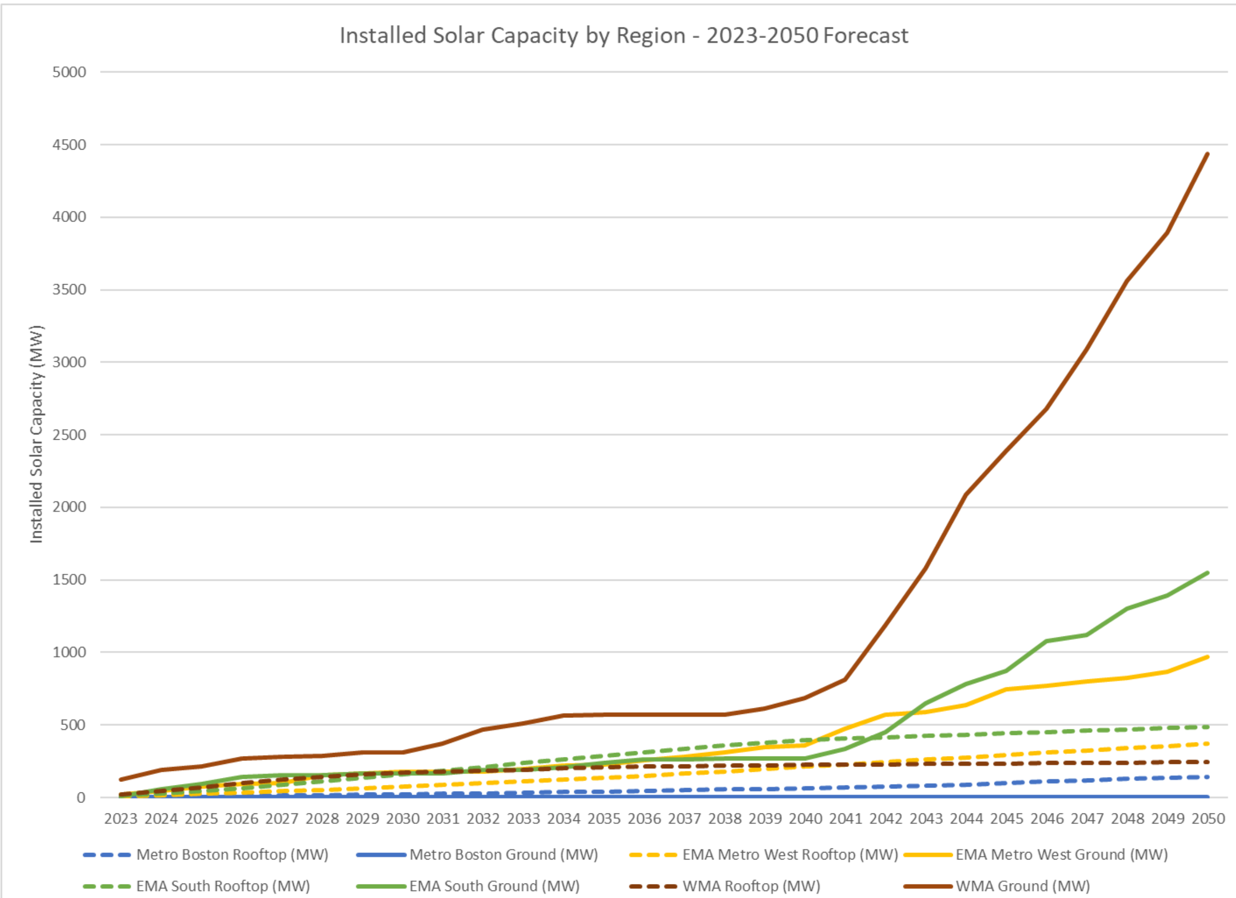


Figure 221: Eversource Installed Solar Capacity by Region – 2023- 2050 Forecast

8.4.1. Technology Assumptions

Solar projects have a nameplate capacity associated for each installation, which is based on the rating of the DC panel. The maximum AC power output is the capacity after adjusting for the AC inverter rating. For behind the meter solar installations, a typical ratio of 1.2 to 1 (DC to AC

223 Set to zero for this consideration for large scale solar.

power) is assumed. For ground mounted installations, the Company assumes a ratio of 1.5 to 1 for the DC panel rating to the AC inverter rating. The time series solar power generated is calculated using specific power calculation models adjusted for weather conditions and based on irradiance data for each substation shown in Section 5.1.2.5. The models take into consideration temperature, humidity, cloud coverage, rain, snow, light intensity, and angle at which the light strikes the panels.

The name plate capacity varies depending on the size of the installation. For ground mount solar projects, a land conversion rate of 4.1 MW/acre is assumed; based on the area of the land technically available for solar (necessary measures to clear and treat the land are assumed complete). For rooftop solar, sites are evaluated based on building classification and parcel land use characteristics. Estimated rooftop panel size considers the average size of installations for historical projects in the customer group.

8.4.2. Adoption Propensity Assumptions

Adoption propensity of solar and storage systems is highly dependent on the type of deployment. Where ground mounted systems are pre-dominantly driven by the availability of cheap, accessible land that is in proximity to distribution infrastructure with sufficient capacity, rooftop systems are driven by the availability of roof space, ownership of the property, and capital to deploy the technology. The Company therefore runs different models for each, using the statewide objectives laid out in the 2050 Massachusetts Decarbonization roadmap (All Options Pathway), Clean Energy, and Climate Plan to ensure annual targets.

8.4.2.1 Rooftop Solar

The state projections for total installed rooftop solar capacity by 2050 (Massachusetts Decarbonization Roadmap) is assumed as the top-level projection. Adoption of rooftop solar in Eversource territory in Massachusetts is assumed to be limited to the total state projection.

The annual solar deployment is determined based on historical trends, the number of potential adopters, and top-level targets. The total number of potential adopters at a system level for each customer type is calculated based on the number of existing customers, new customer growth, and assumptions on the proportion of customers that have access to solar (i.e., live in an area with sufficient exposure of sunlight or housing configuration that allows for solar panels to be installed). Customer type is defined as residential, commercial, or industrial based on the rate code that is applied for the customer. The rate or proportion of customers at a system level that adopts solar in a certain year is estimated by applying an econometric model. The econometric model considers multiple variables and their values in the year of interest and generates a prediction. The model is trained and validated using historical data for the variables of interest. The amount and period of historical data used depends on data availability for a given customer type.

Details on the adoption propensity models for rooftop solar can be found in Section 5.1.2.2 as well as Section 8.1.1 on how the adoption propensity models are tied into the Advanced Forecasting model.

8.4.2.2 Ground Mounted Solar

The adoption of ground mounted solar is heavily driven by economics and policy, assuming that annual deployment is based on state level projections. Projects are forecasted to develop in order of high to low rate of return on investment (ROI) for the customer, the project, and its required capacity is assigned to the associated substation, if capacity is available. Three main factors affect development of ground mount solar projects: cost, infrastructure capacity, and land use constraints. Land use restrictions depend heavily on regulatory guidance. There is also growing resistance in some geographies to ground mount solar making it more difficult to effectively site and permit these projects. Details on ground mounted solar adoption propensity can be found in Section 5.1.2.3 as well as Section 8.1.1 on how the adoption propensity models are tied into the Advanced Forecasting model.

The following table below describes the various sensitivity scenarios considered in the analysis. To allow flexibility for future policy decisions and different land use restrictions, sensitivity analyses are conducted for varying combinations of land use restrictions. In the current base case forecast, all technically available land is assumed to be developable for solar and included in the forecast. This allows for the least constrained analysis that is primarily driven by solar developers and project economics.

Table 72: Ground Mount Solar model scenarios

Scenario	Status	Assumption
Base Case	Current	No CIP fees at any station – developer project bears cost of all upgrades that is triggered Each substation that requires a capacity increase is enabled in 1 year Multiple upgrades allowed
Substation capacity constraint	Sensitivity	No CIP fees at any station – developer project bears cost of all upgrades that is triggered Each substation that requires a capacity increase is enabled in 1 year Limit to 1 - 2 upgrades
Shared upgrade costs	Sensitivity	Stations have associated CIP interconnection fee ($/kW), anticipated capacity upgrade size, and date of upgrade completion Upgrade cost shared (roughly 50/50) between rate payers and project developers
No infrastructure constraint	Sensitivity	Deployment driven purely by project economics All stations have enough hosting capacity
All scenarios	N/A	Parcels generate solar at 4 kW/ acre

Scenario	Status	Assumption
		Parcels that are majority wetland and protected under state register are excluded in its entirety Parcels with existing solar are excluded in its entirety Parcels connect to distribution lines, not transmission

8.4.2.3 BESS Adoption Propensity

The Company considers that in the future, all ground mounted solar installations will be joined with a Battery Energy Storage System (BESS) installation. These BESS installations will not be able to charge from the grid, as such, they do not show up in the Company's Step Loads (as opposed to stand alone storage). Additionally, BESS also does not have the ability to export above the installed solar capacity, and in most cases, are even used to reduce the overall solar export by delaying it to night-time hours after peak shaving.

The significant challenge the Company is facing today is that, while such co-sited storage can be used to firm up solar contribution to peak reduction, the battery dispatch is neither controlled by the EDCs, nor is it happening in load heavy areas with most the solar and solar + storage development happening in WMA and EMA – Southern regions, both regions where solar build out is outpacing load.

The Company is currently not making any assumptions on firm contributions to solar as a peak shaving asset (unless it is a utility owned and operated NWA).

8.4.3. Time of day Assumptions

The Company utilizes year-round solar irradiance models to simulate future solar output (See Section 5.1.1.4 on Weather Adjusted Firm Solar Capacity Model). The year-round irradiance models allow a detailed understanding of when solar sites generate, as well as the "firm" solar capacity assumptions that can be made to allow forecasted solar to offset load increases. The Company reviews solar contribution in two scenarios,

- **Peak Load Forecast:** This is outlined in Section 5.1.1, specifically 5.1.1.4. The Company uses the Firm Solar model to ensure that solar generation that is used to offset peak load can reliably accounted for.
- **Low Load Model:** This model is used for DER interconnections where the limiting criteria is the reserves power flow capability of the power system. Here solar PV, including forecasted solar PV, is modeled at name plate output using the clear sky irradiance profiles. This ensures that the system is not pushed into a condition where low load (spring weekend) meets maximum solar output.

As more and more solar installations go online, the planning peak the company must design its system to gets pushed later and later into the evening for summer peaks. Currently, system peaks occur between 4 and 6pm. The later in the day the coincident peak is, the less incremental benefits can be expected from any new solar installations until the system reaches a point where further solar installations in themselves will no longer reduce the system peak. For the expected winter morning peak, a similar scenario will manifest itself, with an even more significant limitation for solar to contribute to a peak reduction with weather tentatively worse and the sun rising later.

8.5. Offshore Wind Forecasts

Massachusetts leads New England in offshore wind procurements, having contracted 3,241 MW of offshore wind across four projects as of May 2023. In August 2022, Governor Charlie Baker signed House Bill 5060, An Act Driving Clean Energy and Offshore Wind, which amended Section 83C of the Green Communities Act and codified a state goal of procuring 5,600 MW of offshore wind no later than June 30, 2027. This was a significant increase to the 1,600 MW target announced in the 2016 Act to Promote Energy Diversity. House Bill 5060 also allows Massachusetts to coordinate offshore wind solicitations with other New England states and it removed a price cap, which required each new project to offer power at a lower price than its predecessor, if there are fewer than three bidders. On May 2, 2023, the Massachusetts Department of Energy Resources (DOER), in coordination with various Electric Distribution Companies, filed a draft Request for Proposals (RFP) to solicit *up to* 3,600 MW of offshore wind energy with the Massachusetts Department of Public Utilities (DPU). If approved, this would be the state's fourth and largest offshore wind solicitation to date. Proposals can range from 200 MW to 2,400 MW, though the minimum size of the procurement is 400 MW. To be clear, the RFP seeks to procure at least 400 MW and up to 3,600 MW, but not to exceed the maximum amount remaining of the 5,600 MW statutory requirement under Section 83C, taking into account offshore wind contracts still effective at the time bids are due, which is January 31, 2024. The DOER anticipates negotiations around selected projects to begin in June 2024, according to the RFP (Docket No. 23-42).

All of the offshore wind that Massachusetts has procured thus far is proposing to interconnect in the Southeastern Massachusetts and Cape Cod areas. Connecticut's largest project is also proposing to interconnect on Cape Cod. Given the quantity of offshore wind projects that requested interconnection to the transmission system on Cape Cod, the ISO-NE performed two cluster studies to identify the necessary system upgrades. In sum, the *First Cape Cod Resource Integration Study* [224] determined that a new 345 kV line is required to enable 2,800 MW of

[224] "Cape Cod Resource Integration Study Report." *ISO New England*, www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf

offshore wind on Cape Cod. The *Second Cape Cod Resource Integration Study* [225] was canceled when projects withdrew from the queue after preliminary study results indicated several system performances challenges with continued addition of more offshore wind to the Cape Cod area.

The five other New England states combined have procured 1,599 MW of offshore wind as of May 2023. The vast majority of that amount comes from Connecticut and Rhode Island, the latter of which has a pending procurement for an additional 1,000 MW. Bids were due into the ongoing Rhode Island procurement on March 13, 2023 and resulting Power Purchase Agreements are expected to be filed with the Public Utilities Commission for approval around November 2023. The combined total of all New England states offshore wind procurement targets is approximately 9,000 MW. The pathways analysis within the Massachusetts Decarbonization Roadmap forecasted approximately 15 GW of Massachusetts offshore wind by 2050, with New England's offshore wind capacity growing to more than 30 GW by 2050.

Importantly, for New England to procure the levels of offshore wind envisioned in the Massachusetts Decarbonization Roadmap, the US Bureau of Ocean Energy Management (BOEM) will need to auction additional federal offshore wind lease areas since the areas south of Martha's Vineyard are nearly fully subscribed from prior New England and New York procurements. Therefore, it is critical for BOEM to continue progressing with the Gulf of Maine Outer Continental Shelf, which consists of 13,713,825 acres. On August 19, 2022, BOEM published a Request for Interest (RFI) for the Gulf of Maine, which was the first step in BOEM's commercial planning and leasing process. The RFI served to identify the offshore locations that appear most suitable for development, taking into consideration potential impacts to resources and ocean users, and gauge interest in the development of commercial wind energy leases within the RFI Area. More recently, on April 25, 2023, BOEM announced the publication of the Gulf of Maine's Call for Information and Nominations (Call), which opens a 45-day public comment period to assess interest in commercial wind energy development.

8.6. Currently Projected Clean Energy Resource Mix

The 2050 Decarbonization Roadmap outlined by the Commonwealth provides for a variety of future scenarios based on the mix of clean energy resources. The "All Options" pathway in the roadmap is the benchmark scenario and the reference for the High Electrification scenario in the DPU 20-80 Future of Gas study. The electric resource mix from the Massachusetts 2050 Roadmap is provided in the figure below.

For the purpose of the Company's ESMP, the key technologies relevant to the design of the distribution system are represented through the distributed solar capacity projected, both

---

[225] "PAC Update Regarding Second Cape Cod Resource Integration Study." *ISO New England*, www.iso-ne.com/static-assets/documents/2023/01/pac_update_regarding_second_cape_cod_resource_integration_study.

rooftop and ground mounted. Larger generation, such as wind farms, directly connect to the transmission system and are not specifically considered for distribution. For the Basis of the 2035 – 2050 forecast data, the Company is basing, as outlined in Section 8.1 and 8.4 the solar scenario off the "All Options" pathway. By 2050, the roadmap projects 70% of installed solar to be ground mounted and 30% of solar to be rooftop (or approximately 7.0 GW of rooftop solar and 16.2 GW of ground mounted solar) in the Commonwealth.

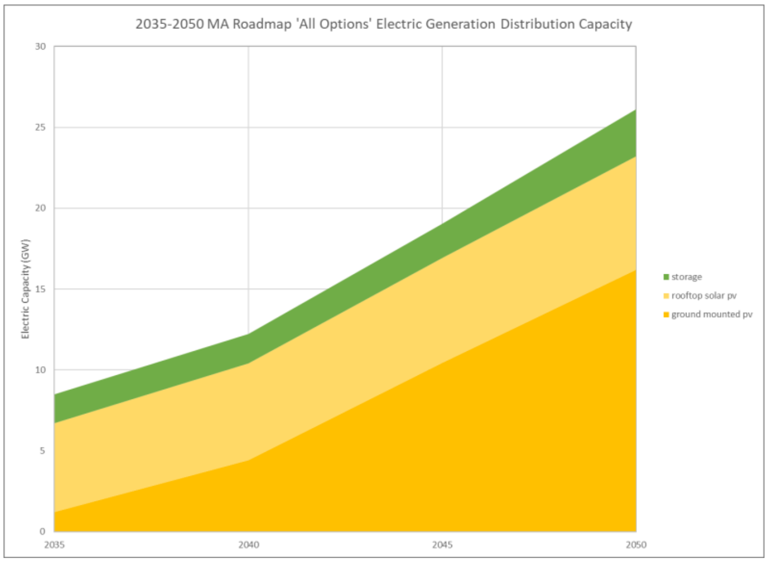


Figure 222: Projected Installed Capacity of Electric Resources in Massachusetts based on the 2050 Roadmap

9.0 2035 - 2050 Solution Set – Building a Decarbonized Future

Section Overview

As noted earlier, the ten-year planned large bulk substations will significantly increase the electrification hosting capacity. Western Massachusetts will be best positioned to enable the full 2050 electrification future at an aggregated bulk station level, followed by Metro West, Southeast and Metro Boston with capacity deficiencies of 2.0 GW, 1.7 GW and 900 MWs, respectively. With the addition of six new bulk substations and upgrades of 11 substations planned beyond 2035, Metro Boston is well positioned to enable the full 2050 electrification future and reducing this aggregated 4.6 GW capacity deficiency down to 3.3 GW (1.7 GW in Metro West and 1.6 GW in Southeast). To close this gap, outside of other solutions, the Company would need to construct 11 additional new substations in the Metro West and 10 additional new substations the Southeast regions.

It is clear that additional solutions beyond large bulk substation additions are needed. These solutions may be different for each sub-region (excluding Western sub-region) where capacity deficiency remains.

- **Metro Boston:** With the addition of two new substations and upgrades to eight substations in this region, Metro Boston is well positioned to enable the full 2050 electrification growth. For instance, conversion of the network steam system that serves downtown Boston to "e-steam" generated by electric boilers served by the transmission system could help reduce the heating electrification demand placed on the distribution system, thereby further improving the available distribution bulk substation headroom.
- **Southeast:** In this sub-region, the vast majority of the 1.6 GW capacity deficiency can be attributed to electric heating – given the larger homes, on a per capita basis, the electric heating demand is substantially higher than in other sub-regions. Given that the Cape area gas heating is serviced by National Grid, closer Gas-Electric coordination with the LDCs across utilities would inform how much of the building space requires heating – and how much of the building space is empty during winter months – and therefore, may not need to be planned for grid electrification capacity despite homeowners converting to air source heat pumps. Further, given that distances between homes are substantial, while network geo-thermal solutions may not be cost effective, single entity ground-Source heat pumps (GSHPs) deployed in this sub-region would be significantly helpful – albeit with higher upfront capital cost. More specifically, if 50% of residential homeowners (assuming year-round occupancy), install GSHPs, the 1.6 GW electric capacity deficiency compresses to 1.1 GW. This in and of itself, reduces the need to construct new bulk substations from ten down to four. To the extent, managed electric vehicle charging could effectuate 20% reduction in EV load, it could potentially further reduce the capacity deficiency to 0.9 GW, potentially driving down the number of new bulk substations from four to three.

- **Metro West:** In Metro West, about 40% of the demand increase beyond 2035 results from Electric Vehicle charging. While it is evident from current academic studies that the majority of EV charging occurs at homes, with policy designs including facilitation of subsidized workplace charging, some of that electric vehicle charging demand could be shifted into Metro Boston to take advantage of the electrification hosting capacity created by the newly constructed bulk substations in this period. Also, because of the significant pool of vehicles plugged in, staggered charging and other managed charging initiatives can then be deployed in downtown areas to optimize demand over the workday time-period. The Company already incorporates this assumption into the load models developed by region which have resulted in the 1.7 GW deficiency in Metro West.[226] Similar to the Southeast, assuming 50% of residential homeowners adopting GSHP, the 1.7 GW capacity deficiency is compressed to 1.2 GW by 2050, which in turn reduces the eleven new bulk substations needed in Metro West region beyond 2035 down to seven. To the extent, managed electric vehicle charging could effectuate 20% reduction in EV load, it could potentially further reduce the capacity deficiency to 0.9 GW, potentially driving down the number of new bulk substations from seven to three.

The Section explores other mechanisms to manage electric demand reductions but finds some specific applications such as Electrification Heating Demand Response as difficult to yield tangible demand reductions sufficient to defer or avoid necessary grid upgrades. The Company is also investigating the potential for more flexible load, through mechanisms such as winter active demand response of process or water heating load as well as vehicle to grid. However, these solution sets are currently in a nascent stage of development, and it is not possible to predict their potential impact on the magnitude of the load peak at this point in time. With the established NWA framework, the Company is well positioned already to combine its front-of-the-meter battery storage with customer sited behind-the-meter DERs that are orchestrated by the Company's distributed energy resource management system (DERMS) platform.

Another critical component of achieving a just transition to a clean energy future is rethinking rate-designs. The Company explores some of the foundational principles of rate-design in this Section. While the Company does not specifically propose new rate designs, the general direction, there may need to be a collective shift away from purely volumetric rates toward demand charge based rate designs for those aspects of service related to delivery to ensure that necessary utility infrastructure investments as well as the Commonwealth's clean energy

[226] Without assuming such programs exist, Electric Vehicle charging demand in Metro West will increase by up to 50%. With the help of residential managed charging programs, especially during coldest days, the Company expects no more than 20% reduction in charging demand. Therefore, if the workplace charging assumptions are rolled back and managed charging is in place, the 1.7 GW capacity deficiency in Metro West would increase by 0.7 GW.

program costs are equitably recovered from the broadest customer segments while ensuring that usage in this electrified future is not being penalized.

Previously, in Section 6, the Company highlighted the five- and ten-year planning solutions primarily driven by forecasted load growth, including step loads, EV and DER adoption in each region, as discussed in Section 5. In this timeframe, heating electrification does not yet have a significant impact on the summer peaks. However, based the long-term electric demand assessment, in alignment with the 2050 Decarbonization Roadmap outlined in Section 8, the Company expects that the winter peak will surpass the summer peak in the 2035 to 2050 timeframe for all regions, and some regions will be winter peaking as early as 2035. This Section discusses the infrastructure, technology and policy needs and deficiencies, and the forward-looking solutions needed to realize a decarbonized future, while maintaining safe, reliable, equitable service for all customers.

9.1. Clean Energy Solutions Including Behind the Meter Incentive Design Scenarios

9.1.1. Buildings: Winter Demand Response Scenarios

In contrast to the ten-year planning horizon, for the 2035-2050 timeframe, electric heating loads will constitute the bulk of the overall peak demand as the system transitions to a winter peaking system. However, as discussed in Section 8.2.4, the nature of the anticipated winter peak demand and the technical performance of heat pumps make demand response (DR) a poor fit for electrified heating loads. The Company continues to monitor developments and affordability of thermal and battery storage technologies that, as well as hybrid heating technologies, which, when paired with heat pumps, could make winter DR a viable solution. Additionally, past winter demand response efforts have had low success achieving reductions from other load types.

The Company previously offered winter electric demand response as part of the 2019-2021 Energy Efficiency Plan. Program participation options included batteries across all customer sectors as well as commercial and industrial (C&I) curtailment, which included allowing customers to switch to an on-site fossil fuel generator.[227] In the 2020-2021 season, only 23 MW of the 87 MW nominated for C&I curtailment performed across the single winter DR event that was called, meaning only 26% of enrolled capacity participated in the event. That is a much lower participation rate than seen with summer electric DR performance, where participation is

---

[227] As of the 2022-2024 Plan, load curtailment that involves switching to on-site generators is no longer allowed in the Mass Save ADR programs.

typically around 70% of nomination. Further, it is likely that a majority of the 23 MW of curtailment that participated was a result of customers switching to fossil fuel generation.

The Company is actively investigating the possibility of other winter demand response offerings, with one consideration being demand response on Hybrid Heating Solutions (See Section 8.1) which allow significantly more electric demand flexibility given their back up fuel sources.

9.1.2. Transport: Electric Vehicle Charging Demand Management Scenarios

Charge management for vehicles remains an area of high importance and growing capability. While there are upsides to charge management, challenges remain to ensuring that its potential is achieved. Managed charging programs that are badly timed or do not randomize activation run the risk of worsening grid conditions. Effective load management techniques also need to consider the charging customer's needs and preferences.

Managed charging programs fall into two categories, Passive and Active. Passive managed charging programs focus on incenting customers to change their own charging behavior. Time-of-Use (TOU) rates or specific incentive design programs that reward off-peak charging are examples of passive managed charging. While passive programs are simple in design and easy to administer, they may not be as effective or robust as active programs. These passive programs are necessarily a bit "blunt" in design, with fairly wide windows of time during which charging is encouraged or discouraged. As a result, they are not effective mechanisms to manage real time locational grid congestion constraints. However, they can be an important participation pathway for customers who may be uncomfortable with active programs.

Active managed charging programs have the capability to directly control charging time, scale, and location in order to achieve a variety of outcomes, such as managing peaks, absorbing excess renewable generation, or supplying some ancillary services. 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, as customers on TOU rates could option into active programs to help them minimize their charging costs without having to think about it.

The potential for managed charging varies by sector and charge type. **Residential at-home charging** is the most promising current application, as most customers plug in when they get home and remain plugged in overnight.[228] This long dwell time means that there is a high amount of flexibility for changing when the charging happens. However, the activation of the start 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., regions with high PV on the system have entirely different load constraints than 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 and of interest to limited customer segments. Given the moderate dwell times and typically repeat users of such charging substations, 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 the impact that these loads have on the overall grid may be on-site batteries that can be charged and discharged in such a way as to flatten the overall load; the company expects these types of solutions to continue to develop over the next decade.

Fleet charging: The Company has begun early engagement with MHDV 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 electrification of MDV and HDV 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 EMS or load balancing software for fleets on their

---

[228] Incorporating Residential Smart Electric Vehicle Charging in Home Energy Management Systems https://www.nrel.gov/docs/fy21osti/78540.pdf

own. However, it is anticipated that electric demand management will be a new concept for many EV fleet customers who are used to managing costs associated with a different fuel resource (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 many 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 X: Electric vehicles 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, all of which serve light duty passenger vehicles. Current V2X functionality falls into three types discussed below.

- **Vehicle-to-Grid (V2G) -** V2G technology is an area 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 MHDV 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. Further, obstacles still remain on utilization cost of batteries, and liabilities for use of the assets.
- **Vehicle-to-Home (V2H) -** In V2H applications, a customer’s EV is used locally 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 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 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. As a general challenge, the time the system would most need to discharge is for the early-morning peak, which directly contradicts customer goals of having fully-charge 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 an unknown at this time.

- **Vehicle-to-Load (V2L) -** V2L technology 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 does, however, and can play an important role in limiting customer inconvenience and dissatisfaction associated with outages of minimal duration.

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.

In summary, managed charging, particularly of personal vehicles charging at home, has potential to help ease grid constraints in the short term, particularly for localized networks with high EV adoption. Once the system becomes winter peaking as a result of electrified heating load, however, electric vehicles are unlikely to play a significant role in contributing to the overall demand of the system, as they will likely have finished charging by the time of the early morning peak (with possible exceptions of fleets with off-hours operating times). Once the larger system is built to accommodate the winter peak, the Company anticipates that the goal of charge management will be to address localized issues. This will be accomplished by a combination of actively managing customers' charging through their participation in a program in addition to price signals reflected in an individual customer's demand charge and/or rates.

9.1.3. Other Load Management Response Scenarios and Associated Preliminary Incentive Designs

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, but programs that were designed to target load shed at the ISO-NE level only cannot serve all 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 new program designs.

9.1.4. Battery Storage Charge Management and Associated Preliminary Incentive Designs

9.1.4.1 Front of the Meter

Large, front of the meter battery storage solutions come in two versions.

a. Stand Alone Storage which is typically deployed as wholesale asset connected to the distribution system or by the EDC as a non-wires alternative (see Section 9.3). If the FTM Storage is a non-wires alternative it is under direct EDC control and the EDC will ensure that the storage does not contribute to a system peak, but rather that it 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. In order to enable wholesale assets to have as much flexibility without driving up system peak or contribute to system upgrades, the Company is starting to interconnect these storage systems using dispatch limiting schedules, see below. In the future, once the DERMS solution the Company has been authorized in DPU 21-80 to procure is in place, such assets would be monitored, and dispatch limited by DERMS.
b. Co-sited with large solar storage solutions aim at reducing interconnection cost of solar sites by conducting peak shaving. These storage solutions absorb generation from solar and discharge to the grid when no solar generation is available, they never charge from the power grid, and they never discharge during peak solar generation. Solar and storage sites, especially Eversource owned, can be considered under NWA dispatch as discussed in Section 9.3.

For front of the meter 3rd party owned, wholesale operating distribution connected storage assets, the Company has developed the dispatch limiting schedules. These schedules provide a maximum charge, and discharge limit for a specific time of day, variable by season, to the battery, allowing the battery to freely operate within that envelope, but never outside of it, and therefore avoid contributing to substation upgrades. Charge limiting schedules are determined upon the interconnection process and remain in effect over the lifetime of the asset acting essentially as a reserved capacity for the storage. The Company will reserve the capacity outlined in the schedule for the battery and consider it for any future interconnection or capacity upgrade study. The following Table 73 shows a sample of such a schedule with values given in percent of installed capacity. Hereby, the percentage values are determined individually for every storage system interconnecting while the time windows and seasons remain fixed.

The time windows for charging and discharging were chosen to align with the current and expected peak load and generation time on the system, as well as to help support participation in the Clean Peak Standard. The Company engaged solar developers through the TSRG and ESIRG working groups to arrive at this consensus.

Table 73: Sample Battery Dispatch Limiting Schedule

Discharge Limiting Schedule	07:00 – 12:00	12:00 – 15:00	15:00 – 19:00	19:00 – 07:00
Winter	75%	50%	75%	100%
Summer	100%	75%	100%	100%
Shoulder	50%	0%	25%	100%
Charge Limiting Schedule	22:00 – 06:00	06:00 – 11:00	11:00 – 15:00	15:00 – 22:00
Winter	75%	50%	25%	75%
Summer	100%	75%	25%	0%
Shoulder	100%	100%	100%	100%

More details on dispatching and controlling front of the meter storage systems can be found in Section 9.3.

9.1.4.2 Behind the Meter

Many customers are pursuing battery storage to meet their own reliability needs, or to manage demand charges. As noted above, current active demand response 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. And with AMI and DERMS fully implemented, the EDCs would be well positioned to use Behind-the-Meter DERs in their operational control, to manage demand on the grid more effectively.

9.2. Aggregate Substation Needs

Major substations are located throughout the state were electrically needed to serve customer load, where there are no substations, the ability to serve increased electric load has the potential to be impaired. Rapidly increasing load makes need for new expanded substation facilities more acute in the geographic location where that load exists. Given the long lead time for these types of projects, and likelihood of permitting and siting challenges, the Company has to plan years ahead to be in a position to serve increased load in the future. In the current operating environment, that means that the Company needs to plan, develop, and build several major infrastructure projects over the next 10 years in order to be ready to serve increased customer load happening in the timeframe of 2035 and 2050[229].

---

[229] Refer to D.P.U 22-22, Exhibit ES-CAH/DPH-1 at 78.

Based on the long-term assessment from Section 8, the existing system from Section 4, as well as the planned build out described in Section 6, Figure 223 below shows the remaining capacity deficit in 2050 when compared to the 2050 Peak demand. The increase on firm capacity from all the planned projects covered in Section 4 and 6, are shown in the Added Firm Capacity by 2035. Additional solution set, that includes substation upgrades and new substations, proposed after 2035 is included as Added Firm Capacity by 2050. As detailed in the following sections, per region, the 2050 solution set includes upgrades to eleven (11) Substations and three new substations that increase the added firm capacity by 1.3 GW. This information is based solely on the bulk substation capacity. Distribution constraints could limit available capacity even further which will require the need for additional distribution line, feeder, and equipment upgrades to match to the enabled substation capacity. It is also based on the base assumptions outlined in Section 8 for the long-term demand assessment, specifically around ASHPs as the key solution driver. These values are consequently open to impacts from policy changes and technology selections. The remaining aggregated bulk substation capacity deficit to meet the 2050 Peak demand yields 2.7 GW. Not included in this consideration are any constraints on the distribution circuit side that will arise from a more than doubling of system load.

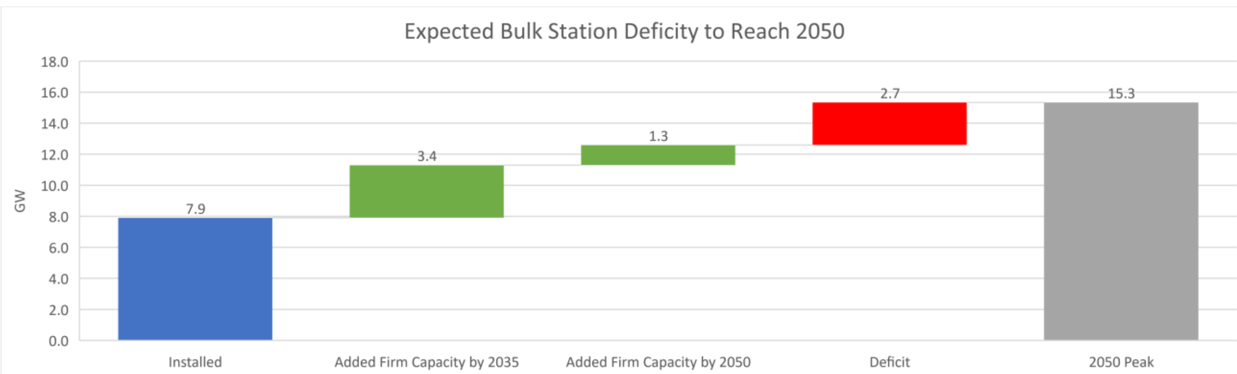


Figure 223: 2050 Bulk Substation Capacity Deficiency – Base Case

However, it must be noted and cannot be ignored that this, and the regional evaluations further down in this Section, are still regional aggregations. This means that it is almost certain that the required additionally installed substation capacity will be significantly more than 2.7 GW due to a handful of reasons:

1. The actual substation deficit is likely higher than 2.7 GW as this number included a 0.6 GW headroom from the WMA Sub-Region. However, that headroom in the WMA Sub-Region is not able to effectuate electrification in the EMA Sub-Regions. As a result, the actual bulk substation need is likely going to be larger than the 2.7 GW, at a minimum by the 0.6 GW to 3.3 GW of bulk station need, which will entirely be focused on the EMA Sub-Regions. Figure 224 below shows the EMA Sub-Regions without WMA, highlighting the 3.3 GW deficit.

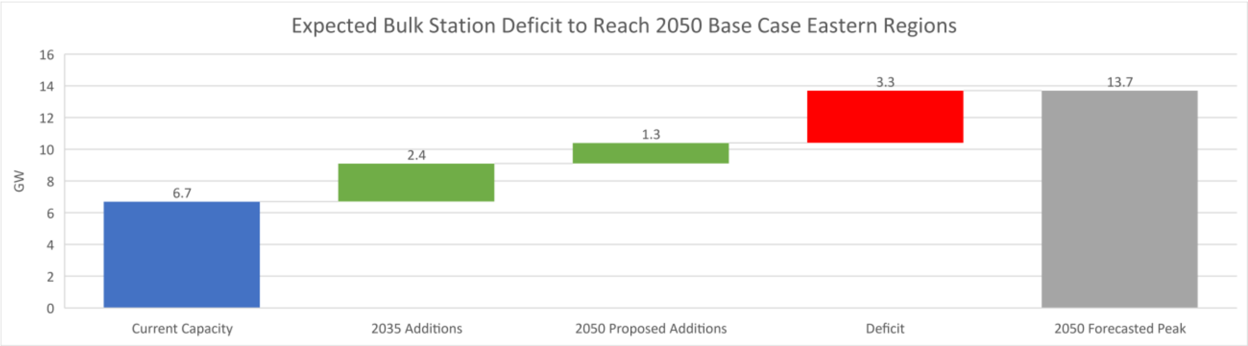


Figure 224: 2050 Bulk Substation Capacity Deficiency – Base Case EMA Sub-Regions only

2. The same effect occurs within individual regions. As an example, in the WMA Sub-Region the available headroom of 0.6 GW (See Section 9.2.4) is developed in the countryside to assist solar development as part of DER Group Studies. However, the load growth will be expected in the Springfield/Amherst region. So even though the entire WMA region, as a whole, has available headroom, it is likely that further capacity additions are required at or near the urban substations as the region electrifies.
3. An additional 2.4 GW (see Figure 225 below) will be required to address the missing solar capacity. This additional capacity is expected, for the most part, be developed in regions where DER developers find it more cost beneficial to site and construct , therefore far away from load centers. The Company expects there to be very little, with some exceptions, overlap of those two build out requirements.

Overall, between all three effects, it is not fully possible to predict the total bulk station capacity required as overlap of benefits between solar and load build out will vary and impacts from mitigations through technology selection needs to be considered. To the extend substations are constructed specifically to address the outstanding capacity deficiency in certain areas that may also reduce the 2.4 GW of remaining solar hosting capacity deficiency, resulting in a potential sub-set of the outstanding capacity. But, considering the base case scenario outlined in Section 8 and the above points, that bulk station deficit is expected in the range of 3.3 GW (100% overlap of load and generation build out) to 5.7 GW (0% overlap of load and generation build out).

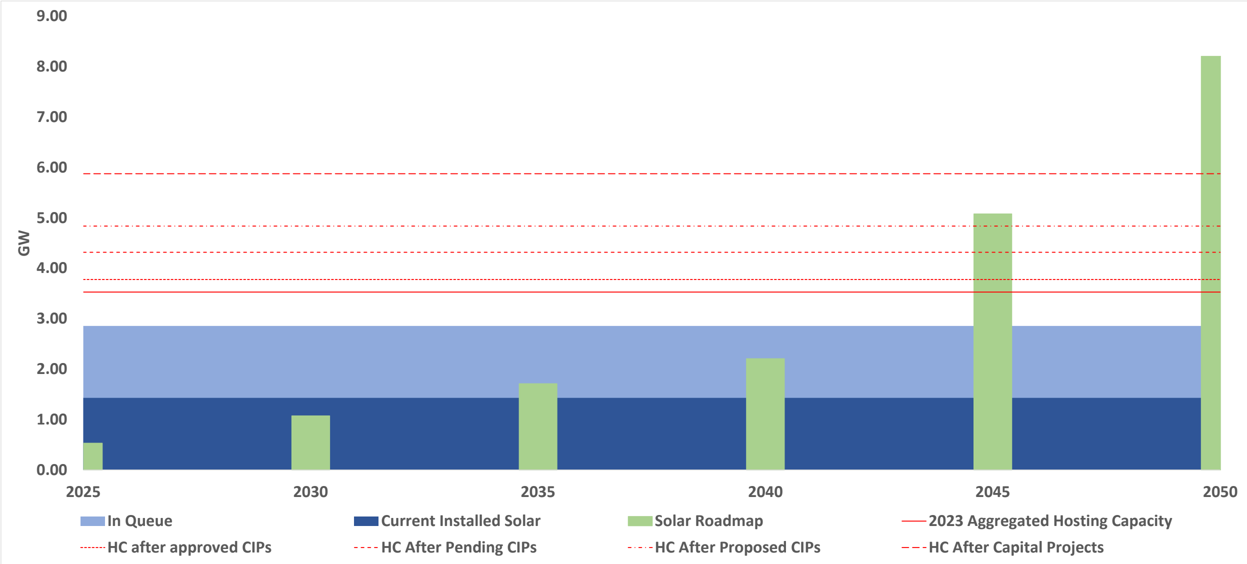


Figure 225: Aggregated Bulk Substation Hosting Capacity Build Out

9.2.1. EMA-North Metro Boston

With a total of 2.0 GW (1.1 GW + 0.9 GW) of aggregated bulk substation capacity proposed in the Metro Sub-Region, only about 400 MW, or the equivalent of 2 full bulk substations is required to fully transition to an ASHP only technology set up. This is due to the significant build out plan the Company is proposing for the next decades in the sub-region. The Metro Boston Sub-Region hereby also poses a unique situation as it is not expecting to see large scale solar development and the load is very close geographically, making it likely that the proposed additions will be able to service the load (not considering any distribution system upgrades). Almost none of the aggregated bulk substation capacity deployed in the Metro Boston Sub-Region will support the solar objectives of the Commonwealth. The only reason which might further drive load is if Boston and the surrounding regions continue their meteoric economic growth past the next 10 years.

The increase on firm capacity from all the EMA-North Metro Boston region planned projects covered in Sections 4 and 6, are shown in the Added Firm Capacity by 2035. Additional solution set proposed after 2035 in this region is included as Added Firm Capacity by 2050. The solution set includes upgrades to eight substations and two new substations that increase the added aggregate bulk substation firm capacity by 0.9 GW. The substation upgrades totaling approximately 0.6 GW out of 0.9 GW of aggregate capacity consist mostly of adding transformers to substations with expansion capabilities – including expandability of new substation placed in service prior to 2035. The new substations totaling approximately 0.3 GW of aggregate firm capacity are proposed for the area of South Boston and Somerville to meet future electrification demand including expected growth in the transportation sector.

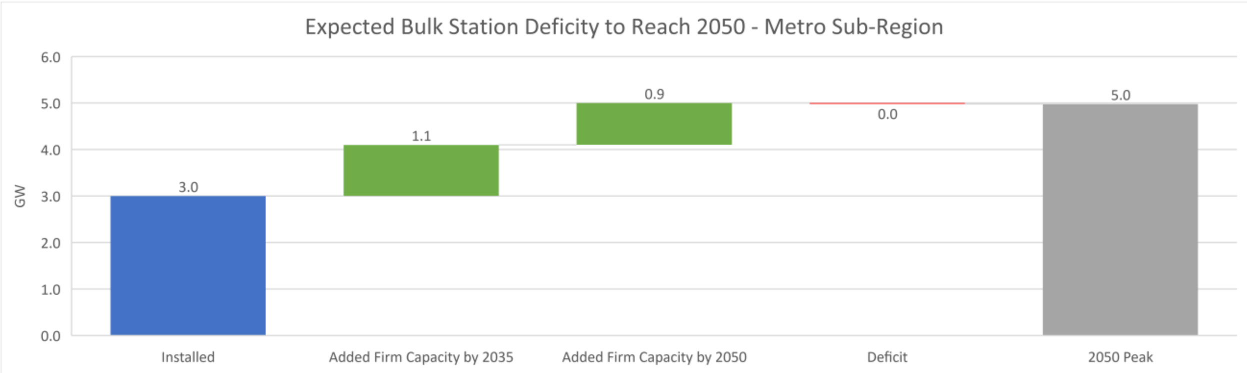


Figure 226: Aggregated Bulk Substation Capacity and Deficit to achieve the 2050 Forecast

The zero-headroom deficit available in this area is an overall sub-region headroom that does not necessarily reflect the local needs; with most of the capacity-driven build out happening in specific neighborhoods and cities within the metro area, the region will likely require capacity-driven updates in the future. For example, as zoning regulations and economic drivers change within the Metro Boston region from 2035 to 2050, the need for additional targeted substation reinforcement will be required to enable those changes. As such, the figure above should not be interpreted as there will never be any new substations or substations upgrades built for load purposes in the Metro Boston Region.

All project solutions expected to be in service by 2034 are included in Section 6. Project solutions expected to be in service beyond 2034, but that are planned to be designed, engineered, and/or start construction prior to 2034 are included below. The two 2 new substations required to meet the deficit in the Metro Boston region fall into this category. None of the eight 8 additional substation upgrades are currently projected to be planned prior to 2034.

- **South Boston Substation** - This project solution is proposing to increase bulk distribution substation capacity in the South Boston neighborhood of the City of Boston where the existing substation is expected to be at capacity in the 20-year planning horizon. The Company is seeking to establish a new 115/14kV distribution substation.
- **Somerville Supply Initiatives Substation** - This project solution is proposing to increase bulk distribution substation capacity in the City of Somerville where the existing substations are expected to be at capacity in the 20-year planning horizon. The Company is looking to establish a new 115/14kV distribution substation.

9.2.2. EMA-North Metro West

The impact on firm capacity from all the EMA-North Metro West region planned and proposed projects covered in Sections 4 and 6, are included in the "Added Firm Capacity by 2035" category in Figure 227 below. Additional solutions planned after 2034 in this region are included as “Added Firm Capacity by 2050”. The solution set includes two new substations that increase the aggregated bulk substation firm capacity by 0.3 GW.

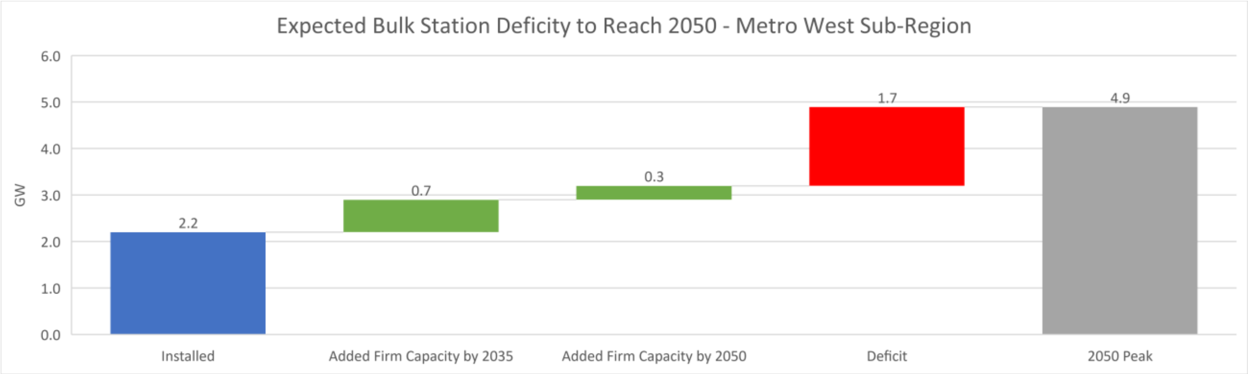


Figure 227: Aggregated Bulk Substation Capacity and Deficit to achieve the 2050 Forecast

Figure 226 below shows the system requirements to meet the total 2050 Peak demand of 4.9 GW in the EMA-North Metro West region. Based on a 2050 plan that includes 23 existing substation, 2 substation upgrades and 6 new substations, a capacity deficit of 1.7 GW will require approximately 11 new substations (with an approximate Firm capacity of 150 MW per substation) and 4 substation upgrades. This will result in a final electric distribution system consisting of 40 substations.

Figure 228: Metro West – Requirements to meet the 2050 Peak Demand

While the Company currently projects in its Section 8 long term solar forecast an additional 2 GW of solar to be developed in the Metro West region, this is mostly based on the constraints in the Southern and WMA Sub-Regions after the full subscription of the approved and pending CIP projects. If all proposed CIPs in the ESMP, as well as future projects are developed in either region, the relatively high property costs in Metro West are likely to redirect development into those regions. While this is not absolute, it can be expected that of the additional 1.7 GW required to achieve the peak load forecast, only a fraction will be able to support the solar objectives outlined in Section 9.2 Figure 230.

All project solutions expected to be in service by 2034 are included in Section 6. Project solutions expected to be in service beyond 2034, but that are planned to be designed, engineered, and/or start construction prior to 2034 are included below. Only two 2 out of the eleven 11 new substations required to meet the 1.7 GW deficit in the Metro West region fall in this category. None of the four 4 additional substation upgrades are currently projected to be planned prior to 2034.

- **Future West Framingham Substation** - This project solution is proposing to increase bulk distribution substation capacity in the Framingham and Ashland areas where the existing substation is expected to be at capacity in the 20-year planning horizon. The Company is looking to establish a new 115/14kV distribution substation near the existing West Framingham 455 substations.
- **Future Newton Substation** - This project solution is proposing to increase bulk distribution substation capacity in the Newton, Waltham, Needham areas where the existing substation is expected to be at capacity in the 20-year planning horizon. The Company is looking to establish a new 115/14kV distribution substation near the existing West Framingham 455 substations.

9.2.3. EMA-South

The impact on firm capacity from all the EMA-South region planned and proposed projects covered in Sections 4 and 6, are shown in the “Added Firm Capacity by 2035” category in Figure 229 below. Additional solutions planned after 2035 in this region are included as “Added Firm Capacity by 2050”. The solution set includes upgrades to one substation that increase the added firm capacity by 0.1 GW.

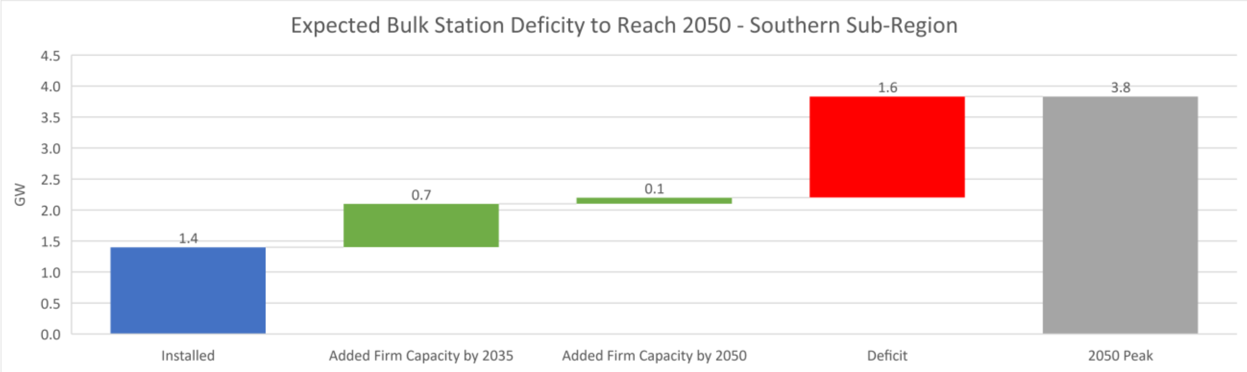


Figure 229: Aggregated Bulk Substation Capacity and Deficit to achieve the 2050 Forecast

Figure 230: Planned System Upgrades vs System Required to Meet 2050 Peak demand**Error! Not a valid bookmark self-reference.**below shows the system requirements to meet the total 2050 Peak demand of 3.8 GW. Based on a 2050 plan that includes 28 existing substation, 7 substation upgrades and 3 new substations, a capacity deficit of 1.6 GW will require approximately 11 new substations (with an approximate Firm capacity of 75MW to 150 MW per substation) and 12 substation upgrades. This will result in a final electric distribution system consisting of 42 substations.

Figure 230: Planned System Upgrades vs System Required to Meet 2050 Peak demand

All project solutions expected to be in service by 2034 are included in Section 6. Project solutions expected to be in service beyond 2034, but that are planned to be designed, engineered, and/or start construction prior to 2034 would be included in this section. However, none of the twelve 12 additional substation upgrades and 11 new substations required to meet the 1.6 GW capacity deficit in the SEMA region are currently projected to be planned prior to 2034.

9.2.4. WMA

The impact on firm capacity from all the EMA-North Metro West region planned and proposed projects covered in Sections 4 and 6, are shown in the "Added Firm Capacity by 2035" category in Figure 231 below. No additional solutions are planned after 2035 in this region, reflected as zero (0) "Added Firm Capacity by 2050", as the aggregated bulk station capacity already shows additional headroom. This will change depending on future CIPs or localized load pockets that might develop. The added firm capacity only includes the solution set planned prior to 2035, including upgrades to ten substations and two new substation that increase the bulk substation firm capacity by 0.9 GW (from 1.3 GW to 2.2 GW) in excess of the 1.6 GW of 2050 Peak demand.

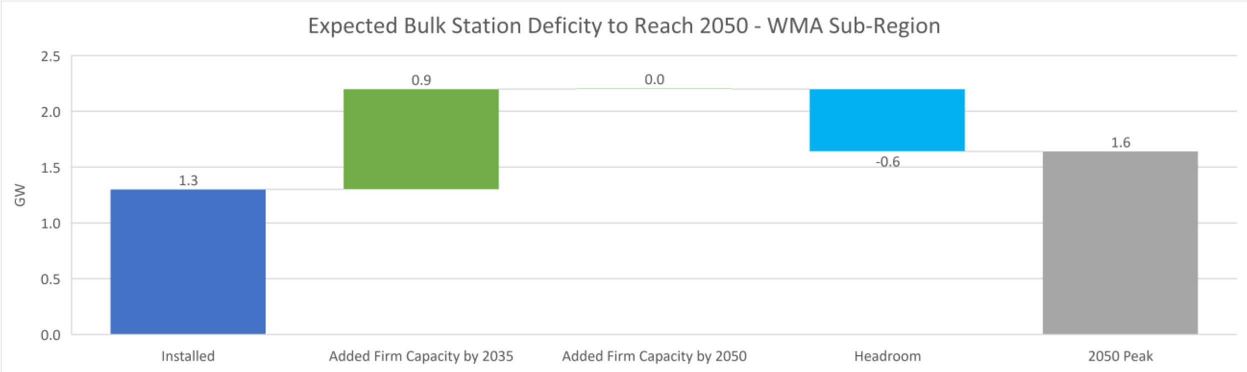


Figure 231: Aggregated Bulk Substation Capacity and Headroom to achieve the 2050 Forecast

The headroom available in Western Mass is an overall sub-region headroom that does not necessarily reflect local needs and constraints. With most of the DER-driven build-out happening in the rural areas, substations in the more urban Springfield/Amherst region will likely require capacity-driven updates in the future. As such, Figure 231 should not be interpreted as proof that there will never be any new substations built for load purposes in the WMA Sub-Region. In fact, based on future solar development and the remaining 2.3 GW of aggregated substation hosting capacity still to be developed, it is entirely possible that the WMA Sub-Region will see both additional substations in the rural areas to enable more DER, as well as substations in the urban areas to support further electrification demand.

All project solutions expected to be in service by 2034 are included in Section 6. Project solutions expected to be in service beyond 2034, but that are planned to be design, engineer, and/or start construction prior to 2034 would be included in this section. However, due to the projected 0.6 GW headroom in WMA none of the projects that will potentially be required to address locational capacity constraints are currently projected to be planned prior to 2034.

9.3. Non-Wires Alternatives – Impact on Substation Deferral

Non-wires alternatives (NWAs) encompass a wide array of solutions from energy efficiency programs, demand response, charge management, or behind the meter residential storage or solar, all the way to utility scale battery storage or solar assets. Essentially, all technologies that directly change the loading of the system can be considered an NWA.

9.3.1. Overview Non-Wires Alternatives

To clarify how the Company thinks about NWAs, a classification into three different categories (Naturally Occurring and Targeted NWAs) must be made.

- As part of the forecast, technologies such as EE and solar PV are forecasted. As detailed in Section 5, the ten-year forecast includes "subtractors" such as EE and solar PV which reduce the forecasted system peak load. Without these subtractors, the system peak in all regions would be significantly higher and capital investments by the Company needed earlier and to a greater extent. These **"naturally occurring" NWAs** are considered by the Company through its forecast and the adjustments made to the forecast.
- As an above and beyond solution **Targeted NWAs** are considered by system planning and deployed by the Company to meet a specific need at a specific location. This occurs when the forecast with, even with the naturally occurring NWAs, is sufficiently high for the Company to trigger a capital project. Every project the Company reviews which is more than $3 million, not related to asset age, and has 3 years until the forecasted need is reviewed for its possibility to be solved with an

NWA. Any NWA solution at this stage is considered an above and beyond the naturally occurring NWA.

- Solutions, especially batteries, can be deployed as **Interconnection NWAs**. These solutions, such as co-sited storage to solar farms, allow for a more cost-effective interconnection of distributed energy resources. These NWAs base their business case on the benefit cost analysis of the developer and do not generate direct value to rate payers, thus receive no value stream other than potentially avoiding paying for some system upgrades from the EDCs. The EDCs do not compensate these NWAs. The Company ensures through specialized hardware that set export (or import limits for e.g., EV chargers) are not exceed and stay withing the requested interconnection limit.

For the Targeted NWA solutions, the Company has published its NWA Framework[230] which outlines in detail how the Company goes about evaluating an NWA for its feasibility to addressing a capacity need. These Targeted NWA Solutions are part of the Company's "toolbelt" as it addresses upcoming system capacity needs in its 10-year planning horizon where every Capital Project that meets certain best practice screening criteria is reviewed of a feasible, targeted NWA.

9.3.2. General Best Practice

NWA projects have the highest chance of successfully being deployed when they address capacity issues with minimal violations that would trigger significant, ideally including transmission, upgrades. The Company has found that best practice for NWAs to be.

- The need is not based on asset condition.
- They have at least 24 months to the capacity need date, ideally 36 months.
- The traditional wires solution is $3 million or more.

Varying versions of these criteria have been used in New England[231] and the Company uses these criteria across its service territory. Once a capital project passes the initial screening, planning engineers conduct a more detailed review of potential NWA solutions. These solutions can encompass one or multiple technologies, including any mix of front and behind of the meter solutions, as well as staged (year by year) roll out. If a technical viable NWA is found, it is evaluated in a Benefit Cost Analysis against the traditional solution.

---

[230] "Eversource NWA Framework Release 2023." *Mass.gov*, www.mass.gov/doc/eversource-nwa-framework-release-2023/download.

[231] https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5080-NGrid-SRP-2021-2023-Three-Year-Plan%2811-20-2020%29V1.pdf

To ensure the best value to the rate payers, the total impact on the revenue requirements is measured for both solutions, the traditional wires solution, as well as the potential NWA. To ensure that the most projects address system constraints and issues can be addressed reliably within the Company's capital plan, it is in the customers interest to have the Company choose the projects with the lowest revenue requirements impact. Since it must be assumed that an NWA can only ever defer, and not permanently replace the traditional project, the value generated by the NWA is that of deferring the traditional solution and the resulting impact on the revenue requirements through the time value of money. This is necessary as at some point, e.g. a substation that would require an upgrade will be so old that it must be rebuilt. At this time, any upgrades to the substation only represent the incremental cost towards the rebuilt, likely making it the most cost-effective solution.

The Company's NWA Framework ensures this by comparing the change in cumulative net present value of the traditional wire solution's revenue requirements with the cumulative net present value of the traditional wire solution's revenue requirements developed for the NWA. Hereby a BCA > 1 would enable the Company to proceed with the proposed NWA. Figure 10 shows the Company's Solution Development Process and how screening for NWAs flows into the process.

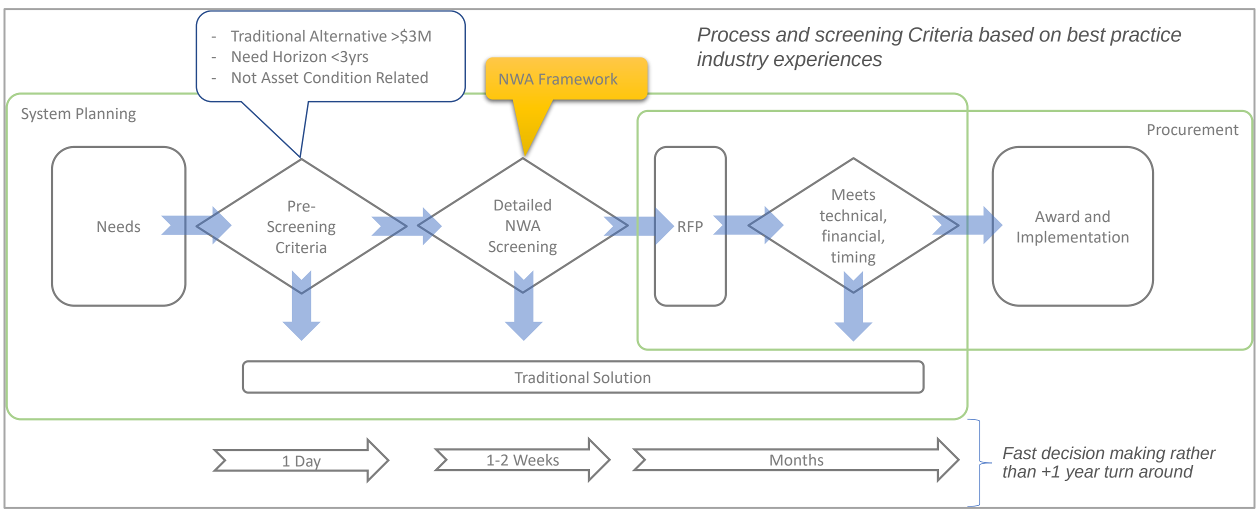


Figure 232: Solution Development Process

To ensure that the NWA Framework stays up to date and represents industry best practices at all times, the Company engages stakeholders on a regular basis.

9.3.3. Challenges with NWA

NWAs are, if deployed to defer capacity projects, a part of the electric power system and therefore subject to the same stringent standards as the rest of the equipment. The Company does not believe that NWAs should be deployed if they reduce quality of service to the customers. With distribution constraints typically very localized, NWAs have a challenge when it comes to guaranteeing this reliability; with typically a small set of NWA resources available to defer a capacity project, little to no de-rating of the solution can be accepted.

Lastly, with a significant increase in electric demand over the next two and a half decades targeted NWA solutions will see fast rising forecasts and capacity deficits shortening the potential timelines of deferral of the traditional solutions. This in turn reduces their overall BCA. It is the Company's experience that that minimal capacity violation projects present the best potential to implement an NWA in order to defer a traditional solution. However, with significant growth happening all over the system, it will be harder to justify targeted NWAs as load ramps up.

9.3.4. Minimum (Technical) Requirements

For NWAs to be considered a reliable solution, the Company's framework, and industry best practice, calls for full operational control, and ideally ownership of the NWA by the EDC. NWAs which are deployed to defer capacity upgrades must provide a 100% availability and performance. This prohibits the NWA from participating in any energy markets or other value generating activity which would require dispatch of the battery as it might create a conflict of interest and/or jeopardize the availability of the resource when needed for distribution system operation. Similarly, ownership of the asset by the EDC ensures that it is continuously maintained and not subject to potentially changing ownership or even being caught in bankruptcy court. It further ensures that a Targeted NWA's performance, or failure thereof, stays within the jurisdictional realm of the Department. The Department, naturally, has jurisdiction over the EDCs, but not of unregulated third-parties who may wish to install an NWA on the distribution system. Allowing unregulated third parties to own NWAs as *distribution assets* would make it nearly impossible for the Department to regulate their performance and cost.

For behind the meter solutions, fleet aggregation might happen through third-party provided solutions, under the pre-requisite that the EDC has dispatch control of aggregated fleets which represent certain feeders or substations. The challenge with aggregated behind the meter solutions is, as discussed in Section 9.1.1, the impact for heating demand is likely to be negligible, while charge management during morning hours will mostly be driven through commercial entities.

9.3.5. Already Included NWA Potential

As outlined in Sections 5 and 8, the Company already considers deferral of capacity needs through NWAs, primarily the deployment of solar, in its forecast. The challenge with solar installations however, is that they are not outputting at anywhere near their peak during the projected highest loads (summer peak evenings, winter peak mornings), as such, their impact is relatively modest with 325 MW of firm peak deferral, which equates to about two bulk substations. The Company also captures, as outlined in Section 5, implicitly any impact of DR on the system peak, but also anticipates that, as discussed in Section 9.1, these impacts will likely shrink in the future.

An unknown quantity to date of peak demand impacts is likely to be gained from intelligent rate design (See Section 9.7.2) which incentives customers to control, much like most commercial customers today, their peak demand.

9.4. System Optimization – Impacts on Electrification Demand

9.4.1. Technology Optimization

Electrified heating will be the largest single driver in system demand over the coming decades with very little flexibility for demand response as outlined in previous Section. Especially critical for electric heating is the very low utilization of just 7% of infrastructure deployed to support such applications (see Section 8.2). Figure 234 below shows the heating demand curve for ASHPs. Very visible the fact that less than 5% of the hours are responsible for more than 50% of the load. These represent the coldest days in the model, specifically those below 10F (see Section 8.2.1 for Technology assumptions). ASHP operate at extremely bad COPs during these conditions. This results in a very low-capacity utilization (<7%) of the system and calls into question the use of ASHPs during the few coldest hours on the system.

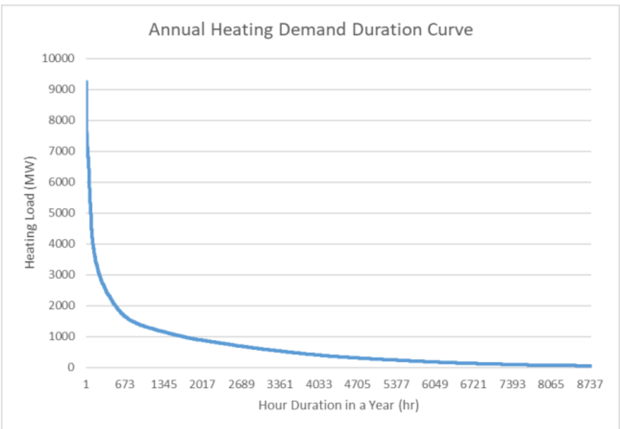


Figure 233: Heating Load Duration Profile for 2050 Base Case

There are several solutions to addressing this issues that ASHP cause in the transition to an electrified future, which all revolve around removing ASHP from utilization during the few coldest days of the year.

1. Ground Source Heat Pumps (GSHP) do not have the issue of their source medium cooling down as much during colder seasons allowing them to retain a much higher average COP (See Section 8.2.1.2 for technical details). GSHPs can be deployed as single entity units or networked together in district systems. The higher average COP also translates directly into a lower overall heating demand on the coldest days. Their challenge is the significantly

higher upfront capital cost, which for individual residential systems, the Company is assuming to range from 1.5x to 2.5x.

2. Hybrid Heating Solutions utilize a backup fuel source that can be burned during extreme cold conditions (See Section 8.2.1.3 for details) and therefore allow the re-dimensioning of ASHPs to smaller units that can operate due to a lower floor temperature at a higher COP. Hybrid Solutions can be fueled by liquified conventional or renewable fuels, or by pipeline supplied fueled, both conventional and renewable. Hybrid solutions can also be utilized in combination with a network of GSHP by providing a fuel backup at a central point and utilizing the medium distribution network to provide heating or cooling as needed.
3. District Solutions utilize centralized heating infrastructure to transport heating or cooling mediums to homes and businesses in the area. The advantage of these systems is, that if done with electric solutions, the single load points can be connected to transmission systems, bypassing distribution build out, or if done with a fuel, they can utilize solutions such as hydrogen as only a single point needs to be supplied, foregoing build out or retention of a separate gas infrastructure. Especially in the Metro Boston Sub-Region such infrastructure already exists.

Specifically, options 2 and 3 allow for the application of decarbonized gas solutions with significant impact on the overall peak system demand of the electric system, allowing an increase in the system utilization, and less distribution and transmission investments. Figure 235 below shows the 2050 Hybrid Heating Scenario which assumes a 100% deployment of ASHPs in combination with a hybrid heating solution cutting in at 10F. Current experience with the deployment of ASHP shows that most customers already retain their conventional heating options as a backup for extremely cold conditions. There is a noticeable drop in overall aggregated substation deficit from 2.7 GW to 1.6 GW.

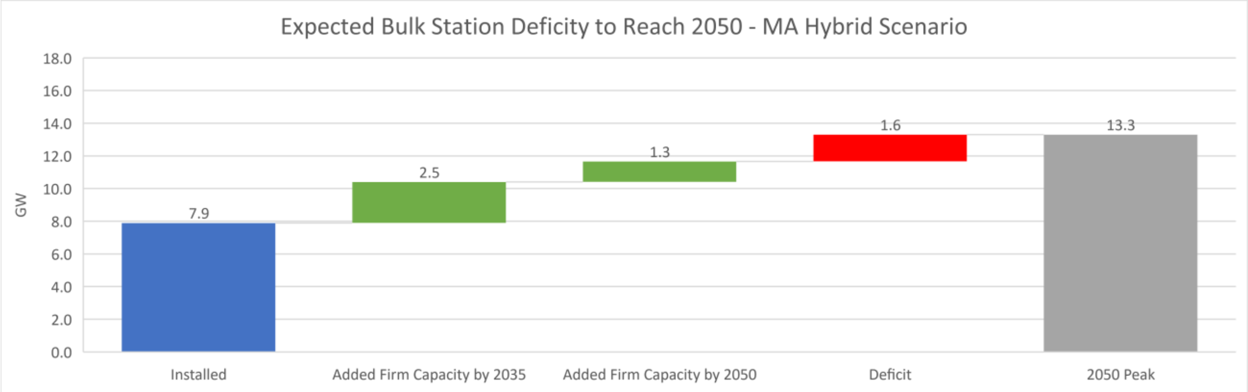


Figure 234:Remaining System Wide Capacity Deficit in the Hybrid Heating Scenario

Especially in high density urban and suburban environments where the amount of distribution infrastructure required would be inverse proportional to the readily available land, such options warrant discussion, especially since district heating solutions are already in place that could potentially utilize either ground source heat pumps, or renewable fuels, to effectively heat large quantities of buildings with a centralized point requiring significantly less distribution infrastructure in the region.

9.4.2. DER and Load Optimization

In an ideal world DER development would happen in the same regions that load manifests itself to allow newly added substation capacity to service two needs, DER integration during day times, and peak loads in the morning or evening. However, due to the extensive land requirements from solar, this is not and will continue to not be the case. Segregation of Load and DER development is in fact likely to increase in the future as less and less cheap land is available closer to load centers and development of DER moves further and further into the countryside. As a result, most stations will have either a very high DER – and very low load utilization, or vice versa, a very low DER – and very high load utilization. This is seen for example today already where new stations in the Metro Boston Sub-Region will likely see only a couple of MW of solar against hundreds of MW of load, and new substations proposed in WMA will never receive any load close to their DER support (this is not the case for rooftop solar).

As shown in Section 9.2, this effect will likely force additional upgrades and investments above and beyond the 5 GW on the base case with very little that can be done in terms of optimizing.

9.4.3. Optimization of DER Hosting Capacity Need

Already today the Company is observing a trend of solar developers requesting interconnection of co-sited solar + storage plants. With the storage asset used for absorbing energy during peak production hours and exporting that energy into the system in later evening hours a valuable service to bulk power markets can be achieved by firming up the solar production. On the distribution side, due to the fact that most solar is where there is relatively little load, those storage assets have little to no value for peak shaving on the distribution system. However, if they are consistently used by developers to interconnect more generation capacity at a lower interconnected capacity (e.g. 5MW solar with 2MW storage requesting 3MW export capacity), a significant drop in the aggregated bulk substation hosting capacity can be achieved. The Company has observed this trend in several installations across the system, but by far not all. In a scenario, where going forward, all solar + storage sites would curtail export capacity towards installed capacity through onsite storage by 40% (5MW → 3MW), the remaining hosting capacity deficit shown in Section 9.2 could be significantly reduced, therefore also reducing the overall need for substation build out.

9.4.4. Optimization of Peak Load Need

With customers adopting more and more electrified technologies into their life (EV, Heating, Induction Stoves) in addition to high load units such as dryers, it will become increasingly more important to incentivize specific behaviors to help minimize the system load (See Section 9.7.2

on potential rate components which might incentivize such behavior and Section 9.3 on NWA approaches for behind the meter applications).

9.5. Alternative Cost-Allocation and Financing Scenarios – Impact on Investments

Based on the analysis in Section 9.2, even after the capacity additions due to new substations and substation upgrades within the ten-year planning horizon (up to 2034), an additional 2.4 GW of aggregate hosting capacity will still be needed to meet the Commonwealth's 2050 objectives for the Company's territory (see Section 9.2). The bulk of this additional hosting capacity will likely be developed in regions with high solar potential, i.e. where land is less expensive, readily available, developable and away from load centers. This tends to be, for the most part, the WMA region and EMA-South. Previously, the Company has submitted Capital Investment (CIP) proposals to the Department with an innovative cost allocation methodology for one DER group in WMA and five DER groups in EMA-South. One CIP has been approved and the other five are still pending approval with the Department. Subsequently, the Company has enhanced its group study approach and cost allocation methodology to account for future planning considerations and has developed plans for seven additional CIPs, two in EMA-North Metro West, one in EMA South and four in WMA. These planned CIPs as well as the cost allocation methodology are described in detail in Section 6. The additional seven Group Studies and CIPs proposed in the ESMP contribute to bringing the bulk system hosting capacity to within 2.4 GW of the state's objectives, as stated above. To close the gap for the remaining 2.4 GW of aggregated bulk station hosting capacity, additional system upgrades will be needed, and the CIP construct is the most viable, economically efficient way to develop and implement these upgrades. However, identifying suitable locations within regions and sizing and siting bulk distribution substation additions or upgrades in an optimal manner, considering transmission, DER and distribution needs is a challenge that requires a focused integrated planning approach.

To identify the areas of the region for development, the Company will initially utilize its ground mounted forecast methodology (See Section 5 and 8 for details) to build adoption rate models for the remaining 2.4 GW of solar after the proposed and planned CIPs. The following Figure 236 shows a map of the currently expected, if not infrastructure constraint, solar build out potential in the Company's territory for the remaining 2.4 GW.

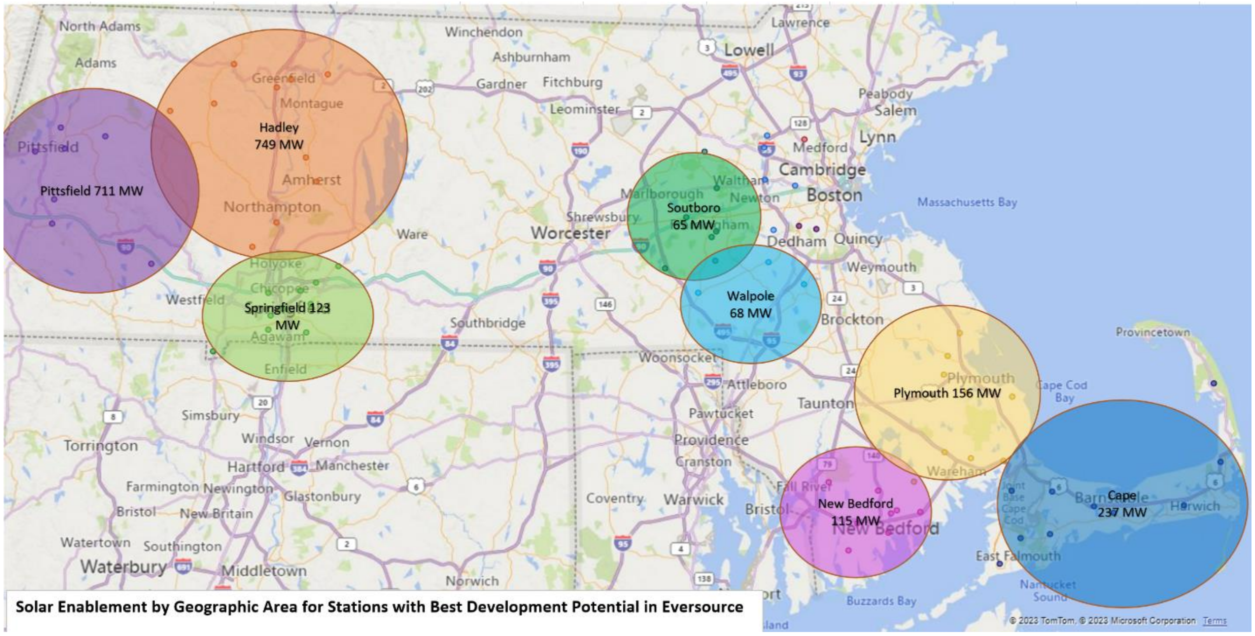


Figure 235: Solar Build Out Potential for the remaining 2.4 GW

In this first step in the integrated planning process, a consolidated ranking of land technical availability solar will be created for use in identifying the regional hot spots in tranches for solar development. Based on these, the cost of infrastructure, regionally specific, and with the inclusion of transmission upgrades, the forecast will show a likely build out path. The regions that are identified through this method to be the most suitable for further solar development, considering land availability, land cost, existing infrastructure, and T&D upgrade costs, will be targeted by the Company for future CIPs proactively to enable development. The Company will also consider electrification enablement to maximize the overlap between enabled solar and enabled electrification. The Department would then need proactively target these regions for development through specifically targeting incentive designs to ensure, especially as the state reaches the saturation, development happens where infrastructure is available.

In order to limit over saturation of solar in a specific region and to not apply a disproportionate burden, the Company will ensure that its Groups are capped in size with the following guidelines.

Once the plausible locations for groups of DER are known, in the next step, the Company would apply its time-tested, analytical, customer-centric approach to expanding the T&D system in an orderly, economic manner. With the groups of forecasted DER demand, the Company would use the Group Study Approach, described in detail in Section 6.1.4.3, to form DER Study Groups in each region based on

1. Clustering of forecasted DER development, size, location.
2. Location/proximity of existing/planned bulk distribution substations and inter-dependency of stations.

3. Load density, electrification growth, reliability needs (length of distribution feeders).
4. Voltage and power quality requirements for the area.
5. Existing or planned transmission infrastructure.

Once DER Study groups are determined, the Company then perform analyses to determine when and where violations in planning criteria and performance requirements would occur.

Based on these analyses, comprehensive distribution solutions are developed for each group to integrate the group DER safely and reliably and accommodate future load growth. Ultimately, the laws of physics and electric service standards dictate whether a service configuration is practical and/or possible. For this reason, the Company strategically places substations near demand centers (load or DER) and defines a service area for each substation based on the ability of distribution feeders, operating at their voltage level, to move power from the source (substation or DER) to loads while maintaining adequate service quality. The number of substations required to meet the demand and their locations depends on a number of factors, but load/demand density or the number of customers and total MW (megawatts) per square mile is one of the primary drivers for the number of substations necessary to serve that level of demand, their size (in terms of number of transformers installed and total capacity), and their proximity to each other. The ultimate solution proactively increases the hosting capacity for additional DER to connect, closing the 2050 gap in tranches. Figure 237 shows, schematically, how the Company is envisioning filling the remaining bulk station aggregated hosting capacity. The actual size and number of Tranches will vary.

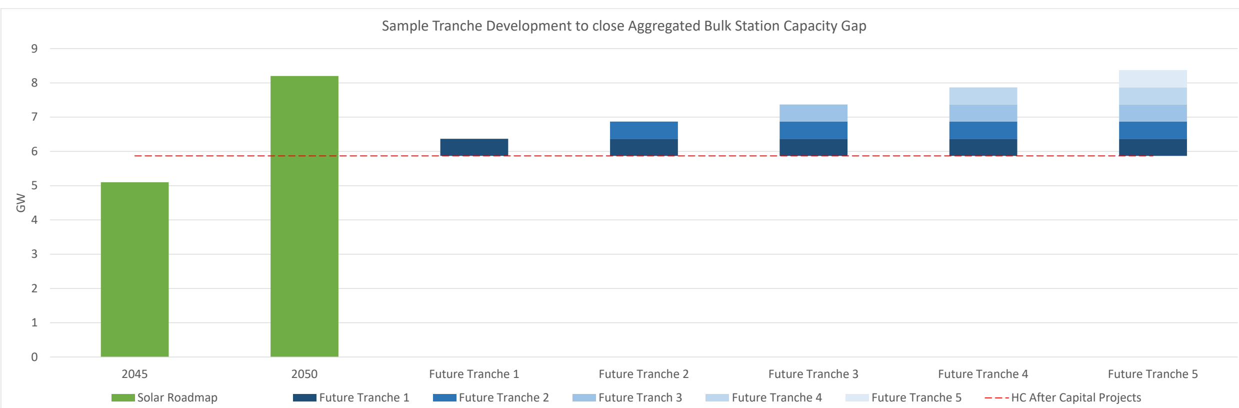


Figure 236: Schematic Build out of CIP Tranches to fill remaining solar gap

The final step in the process requires aggregation of the load and enabled DER capacity to the transmission level and identifying constraints on the transmission system, considering generation sources, retirements and commitments. The result is a comprehensive plan that identifies the need for coordinated distribution and transmission solutions in local areas to support load and DER growth.

Cost allocation for each future group study is expected to follow the same methodology described in Section 6.

9.5.1. CIP 2.0 (Solar) projects and cost allocation

Solar projects are expected, as outlined in Section 6, to continue paying a CIP fee based on their interconnecting capacity in MW.

9.5.2. CIP 3.0 (battery storage) projects and cost allocation

Battery storage systems will, for their export capacity, pay a CIP fee analogous to solar sites based on their maximum export capacity in MW. For the load side under current developments, distribution connected battery storage systems will pay distribution rates based on their peak load which will offset cost to other rate paying customers. The Company currently has no further plans to charge a load CIP of batteries.

9.6. Enabling a Just Transition through Policy, Technology, and Infrastructure Innovation

Eversource is committed to delivering a clean, equitable and affordable energy future for all. Eversource recognizes the critical need to address climate change and are committed to meeting the climate and equity goals established by the Commonwealth. In addition to ensuring that the customers and communities Eversource serves have equitable access to safe and reliable energy service, Eversource is also committed to ensuring the technological and environmental benefits the clean energy transition will bring are felt by all.

As the Company continues to develop future programs that ensure all customers are equitably served, it will commit to the following approaches:

- Outreach to environmental justice stakeholders across the service territory in early stages of program development in order to develop awareness of forthcoming proposals, identify priorities and concerns, and incorporate stakeholder feedback in design of programs;
- Partner with stakeholders to improve understanding of barriers to program participation for disadvantaged populations, and consider both programmatic design as well as necessary policy reforms to address these barriers;
- Collaborate with stakeholders to develop meaningful metrics that support objectives of increased access, engagement, and realization of program benefits in priority communities; and
- Advocate for policy reforms that support the ability of disadvantaged customers to participate in customer programs.

•

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

Eversource recognizes that populations in EJ 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 EJ communities in its clean energy program design and in its community and customer outreach and engagement, as it has done in its EE and EV programs to date.

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

Eversource designs rates that reflect the costs and usage characteristics of each rate class as they have changed over time, and considers precedents and procedures established by the Department of Public Utilities. In designing rates Eversource applies core rate design principles while incorporating public policy directives.

The average long-run cost to customers can be expected to be mitigated to some extent due to the increased sales volumes that will come with electrification. 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 the 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 maintaining and operating the distribution infrastructure, 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 consist of three key design components:

1. <u>Fixed Charges</u>: These rates are a flat fee charged to customers regardless of their electricity usage. Fixed charges typically cover the utility'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. <u>Demand Charges</u>: 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. Energy supply is procured by the utility from a supplier and ultimately reflects the commodity pricing in wholesale markets. Volumetric charges exist in distribution rates as a legacy of unbundling in order to maintain price continuity. They are also used to balance the impact of demand charges based on customer load profiles. Volumetric rates encourage customers to reduce their total usage, but do not incentivize customers to manage their demand.

The revenue requirement recovered by Eversource must be approved by the Department of Public Utilities along with the pricing designed to collect Eversource'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 Electric Sector Modernization 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 (i.e. a reliable electric power system that can deliver clean energy). However, it is only one tool in a strategy that includes energy efficiency and efficient investment in the distribution system.

Electrification of the home and business and the growth of electric vehicles means that more electric energy will be required than ever before. Eversource is taking steps to invest in its distribution system to accommodate this load and the renewable resources that will be introduced to serve future load. Continued load growth and investment must be managed to ensure that customers do not face an exponential growth in the cost to serve them. Cost control is inherent in the regulatory process as all investments made by Eversource cannot be recovered unless they are approved by the Department of Public Utilities and deemed to be just and reasonable. In reviewing and approving rates, the Department has long adhered to commonly accepted ratemaking principles[232]. These are 1) efficiency, 2) simplicity, 3) continuity, 4) fairness, and 5) earnings stability. These five principles remain sound and should continue to be relied on in the evaluation of future rate proposals.

[232] Espoused by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen in Principles of Public Utility Rates.

1. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their 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.

   From the EDC perspective, demand charges reflect the most efficient form of rate design. The primary function of the EDC is to operate and maintain an 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. For this reason, demand charges are most efficient because customers are charged based on their demand at a point in time. Volumetric charges, on the other hand, 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 demand among customers due to various installations ranging from modern appliances to electric vehicles, the Company proposes that demand charges be given greater consideration in the evaluation of future base distribution rate proposals.

2. 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 general 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 the potential 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 some caution should be given to complex rate designs. 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 consider that customers are diverse. For example, the development of the competitive energy supply market offers some 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. An individual residential

customer, on the other hand, does not have such resources or bargaining power. Many do not fully understand energy markets and are vulnerable to exploitation by unscrupulous parties.

3. 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 of 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 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 don't see an immediate advantage are unlikely to elect the rate.

4. 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.

   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.

5. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. Earnings 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 don't 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 leave Eversource under-recovered and ultimately result in increased rates for all other customers. In order 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 earnings stability need to be weighed against each other and cannot be viewed in isolation. Often times, one principle may be emphasized over another in order to achieve an outcome that meets the real world needs of customers, policymakers, and the EDCs. Eversource believes that greater 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

Eversource recognizes that populations in EJ 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 EJ communities in its clean energy program design and in its community and customer outreach and engagement, as it has done in its EE and EV programs to date.

It also warrants discussion on how incentives that are paid to customers are recovered through rates e.g., EE charges or, if incentives are managed through rate design, distribution charges. As the Company moves to an increasingly electrified system, it is important that careful consideration be given to cost allocation and rate design principles to ensure a just transition. It will be important to design rates and allocate costs so as not to shift costs around or over-burden any particular class of customers. The Company is concerned that the transition to an electrified future happens in an equitable and just manner and supports the establishment of the Equity Working Group as part of the GMAC to address concerns.

9.7. New Technology platforms

In all scenarios outlined in Section 8 the Company assumes a natural distribution of load, be it heat pumps or electric vehicles, and discusses in both Sections 8 and 9 how potential load / charge management might be used to mitigate these impacts. It however needs to be clearly understood that load and charge management, if not conducted by the EDC, can have the opposite effect. Distributed resources (Electric vehicles, solar, storage) that are aggregated by 3rd parties (commonly referred to as virtual power plants, or VPPs) and dispatch towards bulk energy markets can have severe impacts on the system. By introducing an external trigger event, such as an ISO price signal, would significantly increase the coincident factor of the aggregated resources. Especially FERC Order 22-22 allows for such aggregation and commitment to energy markets posing a real challenge for the EDCs.

The Company is working towards implementation of what is more commonly known as a Distribution System Operator (DSO) solution which enables the effective linking of the different dispatch requirements between resources participating in energy markets, acting as NWAs, and system constraints the Company had already laid out in MA D.P.U. 21-80. Although specific requirements for FERC Order 2222 implementation remain under consideration, the Company anticipates it will need to address the following operational needs in advance of full implementation. These needs are applicable for all types of DER dispatch, including use of DER assets to address distribution system constraints.

1. The Company must have sufficient information regarding dispatch schedules to conduct operational load forecasts used to inform switching operations, maintenance, or respond to anticipated critical events such heat waves.
2. Dispatch decisions must be informed by an awareness of anticipated system constraints, planned outages, and other events that might limit access to resources before final plans are established. Absent this awareness there may be a need for curtailment of DERs by the EDCs based on real time system conditions.
3. Absent coordinated dispatch for wholesale and distribution use cases, the Company will have no avenue for providing additional incentives for resource dispatch to address real time congested systems, potentially requiring incremental system investments.
4. During critical system events such as N-1 conditions (e.g., outages, faults, storm events), real time communication between aggregators and utilities is essential as system conditions change rapidly, requiring an adjustment of dispatch.

Analysis and communication of grid conditions with the potential to affect DER dispatch may be facilitated by categorization of system constraints based on their level of severity. In its initial planning relative to DER dispatch, the Company has adopted an abstracted version of a grid "traffic light" concept established by a European Association of Energy and Water Industries, BDEW. This nomenclature is based on the definitions of "green", "yellow" and "red" phases as summarized in Figure 238.

Real Time	Immediate risk of system failure caused by **unforeseen** events	Utility control systems DMS and DERMS take control or coordinate with aggregators and DERs to manage constraints
Intra Day / Day Ahead	a) The distribution system is **constrained** requiring dispatch to mediate **or** b) There is **insufficient capacity** for aggregators to call all available resources	Utility provides guidance on dispatch limits
Intra Day / Day Ahead	a) The distribution system **does not require dispatch** to mediate a constraint **and** b) There is **enough capacity** for aggregators to call all their available resources	Aggregators have no limitations

Figure 237: Overview System Conditions and Actions

Although there are many factors related to policies, technology, markets and customer preferences that will shape the future of DER participation as grid assets, it is clear that the demand for maximizing the value of DER for multiple use cases will grow considerably over the next four years.

10.0 Reliable and Resilient Distribution System

Section Overview

In the Company's Resilience Plan, Eversource presents its' first proposed Resilience Planning metric and associated data-driven Resilience Plan focused on vulnerable communities to ultimately reduce storm costs and improve customer service. As part of this report, Eversource also presents at length the results of its recently completed tri-state climate change vulnerability study.

As noted previously, the Climate Mitigation Plans and Climate Adaptation Plans are interlinked from the customer standpoint. An electrified and clean energy enabled distribution infrastructure fails if it is not also designed to protect against extreme events driven by climate change.

Reliability: The Company's Base Reliability programs to replace aging and obsolete overhead, underground and substation equipment, and various programs to address poor performing circuits, serve as the bed rock of any utility programs for Eversource to continue to maintain top quartile reliability in the industry. Utility reliability performance metrics are commonly measured in terms of SAIDI, SAIFI and CAIDI, as shown in Chapter 4. The company commits to maintaining top quartile reliability by establishing industry leading targets and taking a data-driven approach to maintaining and improving reliability performance through a variety of programs listed in detail in Chapter 10.2.

Resilience: The Company apportions a significant part of its Resilience Plan toward a comprehensive review of the Commonwealth's Climate Assessment and Hazard Mitigation and Climate Adaptation Plan (SHMCAP). Eversource identifies a high level of result and methodological approach alignment between SHMCAP and the Company's study, but also identifies several synergistic areas to learn from the Commonwealth's identified vulnerabilities, in terms of both climate hazards relevant to the New England area as well as highly granular vulnerable population linkages to specific climate hazards. In an effort to promote transparency and state-wide awareness on climate change, the Company commits to socializing the granular results of the Company's climate study with the various agencies to commence collaborative planning and a common understanding of shared risks. However, prior to considering future worsening climate conditions, the Company recognizes New England's already increased exposure to storms. New England was hit by three catastrophic storms since 2010 – Tropical Storm Isaias, Hurricane Sandy and Hurricane Irene. New England was also impacted by Winter Storm Alfred, also commonly known as the 2011 Halloween Nor'easter, which arrived just two months after Irene. When looking at 40 years of Storm data, these storms range between 1 in 30-to-50-year events. But shortening the lookback period to the most recent 15 years of storm data, suggests a dramatic compression in catastrophic storm probabilities in the range of 1 in 19-to-23-year events. This substantial compression in storm probabilities when looking at more recent storm history demonstrates that these catastrophic storms are becoming significantly more likely in New England. Within this ESMP, the Company is leading by developing a Resilience metric, to assess location and magnitude of vulnerabilities on the system, associated distribution system outages, but also unique hardening plans to address each damaged circuit at a device level granularity. Chapter 10 also includes the Company's methodology to maximize resilience benefits in the most cost effective manner. Specifically, with the implementation of the ten-year plan, the Company projects a reduction in Storm costs as well as quantifies reduction in customer cost of interruption. Given that these hardening investments would last well beyond thirty years, it is anticipated that these benefits to grow especially considering future worsening climate conditions.

To meaningfully assess future value of resilience, the Company is now assessing the results of its Climate Vulnerability Study similar to the Commonwealth's Climate Assessment and Hazard Mitigation and Climate Adaptation Plan. This study looks at Extreme Temperature Magnitude and Duration, Heavy Precipitation, Drought, Sea Level Rise and Storm Surge out to 2080 under two different Climate Change scenarios (SSP24.5 and SSP8.5). Coined as a middle of the road scenario by United Nations' Intergovernmental Panel on Climate Change, the SSP2-4.5 scenario assume progress toward sustainability is slow, with temperatures rising by 2.7 degrees C by the end of the century with CO2 emissions hovering around current levels before starting to fall mid-century but failing to reach net zero by 2100. By comparison, SSP5-8.5 scenario assumes global economic growth fueled by fossil fuels with a doubling of CO2 emissions by 2050 and with temperatures rising by 4.4 degrees C by the end of the century. Specifically, the upper tail of the daily maximum temperature are projected to increase by 3.6F to 6.7F in Boston by 2050 and the upper tail of the daily average temperature are projected to increase by 3.7F to 7.7F in Boston by 2050. Both the average and maximum temperature projected increase supports a theory that this may be a new normal representation of blue-sky days' performance too. Under SSP2-4.5, the 50th percentile of the annual hottest daily temperature in Boston in 2050 is projected to be 100F, while under SSP5-8.5 the 90th percentile of the annual hottest daily temperature in Boston in 2050 is expected to be 103F. About 5 to 7 heat waves are expected annually by 2050, while the current baseline is about 2 heat waves annually. Additionally, those heat waves are projected to be much more prolonged by 2050. Under SSP2-4.5 50th percentile, the duration of the annual longest heat wave is expected to be 8-15 days in 2050, about double from the current 4-7 days.

While the Eversource climate vulnerable study findings were finalized in June and given the significant downstream changes this study will have on planning, new design standards, new construction standards as well as potentially new equipment designs, the timing of this ESMP filing does not provide the company sufficient time to translate the results of the study into those specific proposed changes. However, given its criticality and the Company's commitment to safe and reliable service and a resilient grid, the company commits to proposing updates to its Distribution Planning and Design standards by the end of 2024. By the end of 2024, the Company plans to translate these Climate vulnerability study results into updates to its Distribution Planning and Equipment Design standards. As a starting point, the Company is proposing at this point in time a high-level impact and mitigations table, associating the studied climate hazards to asset types most affected and to potential mitigations.

10.1. Review of the Commonwealth's Climate Assessment and Hazard Mitigation and Climate Adaptation Plans

The Massachusetts Integrated State Hazard Mitigation and Climate Adaptation Plan (SHMCAP), established in 2018, was designed to integrate hazard mitigation and climate adaptation plans that were formerly performed in isolation in many jurisdictions and Massachusetts government sectors. The plan focuses on using historical data together with forecasts when planning for resilience. The 5-year update of the plan is expected in September 2023 (i.e., after the time that this report was put together).

The SHMCAP focuses on 4 core climate hazards; 1) precipitation, 2) sea level rise, 3) rising temperature, and 4) extreme weather and examines multiple facets under each hazard. For example, precipitation is assessed as inland flooding, drought, and landslides. SHMCAP also assesses two categories of non-climate hazards: earthquakes and human-made attacks. For each hazard and its sub-sections, the following 5 sectors are assessed: populations, government, built environment, natural resources and the environment, and economy. Lastly, SHMCAP goes into discussing the adaptive capacity of the state, the plans for administering state agency and the proposed ways to implement, coordinate, and maintain the plans.

Throughout the SHMCAP document, building resilience, climate change adaptation and hazard mitigation are used almost interchangeably.

The five core goals of SHMCAP are:

1. Integrate programs and build institutional capacity to enhance the state's resilience to natural hazards and climate change, where capacity is defined as the ability to adjust or modify to adapt to changing conditions (in this case due to climate change impacts)
2. Develop forward-looking policies, plans, and regulations to reduce the impacts of natural hazards and climate change
3. Understand vulnerabilities and risks to develop risk-reduction strategies for current and future conditions
4. Invest in performance-based solutions
5. Increase education, awareness, and incentives to act.

The review of SHMCAP that is presented in this Section will focus on the content of the plan that is relevant to EDCs. The Company and its assets fall under the "Built Environment" in terms of the sectors of relevance of SHMCAP. Economic losses in the economy sector include utility restoration costs. As can be seen in Section 10.4 below, the Company has commissioned a study with similar purpose.

Overall, the Company's assessment of SHMCAP is summarized below:

- The climate hazards studied as part of SHMCAP align with the Company's climate vulnerability study. As can be seen in Section 10.3, the Eversource climate study focuses on the four climate hazards of SHMCAP, plus storm surge. Also, the Company's study considers drought and energy demand as separate climate hazards, while the MA report considers it a sub-category of precipitation and temperature respectively.
- The SHMCAP has a lookahead horizon of 2100, while Eversource's climate study goes out to 2080. Some of the State's forecasts are performed in coarser scales spatially, compared to the 6km x 6km downscaled models necessary in the Company's study to identify specific grid vulnerabilities. A sample of the highly spatially granular results from the study are shown in Section 10.4. In Section 10.5, the peaks of the climate science variables shown in these heat maps are related to Area Work Centers (AWCs) with the overall objective to drill down to specific assets with expected impacts (for each climate hazard/ variable).
- SHMCAP performs a single scenario analysis, while the Company's study was performed under two climate change scenarios and assessed various percentiles within each. This report highlights SSP2-4.5 50th percentile and SSP5-8.5 90th percentile.
- SHMCAP views most climate hazards through the lens of their extreme manifestations, while Eversource's study tries to assess extreme events as well as chronic problems, considered the "new normal", showing how a typical blue-sky day differs in the warming climate future from current levels.
- SHMCAP includes a section on warning times for each events/climate hazard. While an important property for response and recovery, the EDCs need to create forecasts that allow them to proactively harden the system. For example, instead of a short-term forecast of an upcoming event and its path, a longer-term forecasted combination of possible event paths and of an event's return period is needed to inform EDCs' resilience plans and associated quantification of long-term benefits. EDCs need to make investments to proactively harden the system as well as reactively expend human capital and resources for event response and recovery. Cost recovery through the rate base requires regulatory approval of the additional spending. Some EDC resilience enhancing projects are multi-year projects, hence may not be fully built if the return period of an event is short.
- Efforts by other entities to harden their systems may have a positive or negative impact on EDC infrastructure and vice versa. For example, state-led coastal flooding mitigation

measures could affect Eversource substations in flood prone areas and reduce the needed elevation of these substation equipment. These impacts are pronounced if one considers that other utilities' or entities' infrastructure may be considered critical customers of the EDC and as such influence the EDC planning priorities and operations.

- SHMCAP has detailed sections on the exposure and vulnerability of disadvantaged and Environmental Justice populations, with details specific to each climate hazard. Since cumulative metrics of disadvantaged or Environmental Justice populations are made up of a variety of disparate inputs, including economic, social and educational metrics, per-climate hazard views may allow for finer understanding of disadvantaged stakeholders. The Company is including Environmental Justice populations' considerations in its resilience plans, as mentioned in Section 10.5, and is looking forward to using specific sensitive population metrics and indices.

In what follows, a more at length review of SHMCAP is provided.

The last two steps of investing in performance-based solutions and incentives to act fall in line and promote the goals of performance-based regulations enacted by the Massachusetts DPU for electric utilities.

With regard to the first climate hazard presented in SHMCAP, precipitation, the Company's assets are mentioned as an impacted part of the built environment. The Company fully agrees that precipitation and potential associated flooding could be impactful to utility owned equipment. The Company, however, considers broader impacts of precipitation, expanding beyond underground assets. Precipitation is oftentimes combined with other phenomena like wind that can impact exposed overhead systems. Moreover, flooding could prohibit or delay the Company's restoration efforts, as is indirectly mentioned in the Transportation section on page 4-28.

SHMCAP discusses the impacts of drought as a sub-section of precipitation. The Company's latest climate vulnerability study supports the conclusion of the report that drought will get worse in the future due to climate change, as mentioned in more detail in Section 10.4. The extreme event assessment in Eversource's study recognizes an additional secondary hazard of drought; that of vegetation impacts from drought followed by a high wind or tropical storm event. Such compound and consecutive events can increase the number of hazard trees that the overhead electric assets are susceptible to.

The last subsection of precipitation, landslide, is recognized in SHMCAP as potentially impactful to utility poles. Additionally, landslides can cause trees to intercept or fall on power lines. Pole integrity programs, including pole inspections, maintenance, and replacements, as well as updated Company Standards to higher class poles with sturdier materials and construction can hedge against such events. A secondary impact of landslide is delaying or blocking restoration due to road closures.

Next, SHMCAP goes into the hazard of sea level rise. The intensity and frequency of flooding events is reportedly increasing recently in Massachusetts and the energy-related built infrastructure impacts are briefly discussed. The Company's substation elevation standards align with the logic of the data presented in SHMCAP, including consideration of transportation access during flooding events also being within the Company's substation design Standards. Coastal erosion is not listed as impactful to energy infrastructure. Tsunamis on the other hand are listed as potentially impacting energy infrastructure but are rare events for Massachusetts. Tsunamis are a 1-in-39 years event for the East Coast of the county based on historical data and a significant tsunami has not hit Massachusetts since 1950.

also expects a warming climate, which is the result of the Company's study as well. Both SHMCAP and Eversource's study determined rising temperatures can be expected. The MA document defines a heat wave as three consecutive days where the maximum daily temperature is above 90F and mentions that urban areas tend to have more heat impacts and uses the term "heat islands". The results of the Company's climate vulnerability study align well with that statement, since the downscaled results show various metrics around temperature peaking in the urban/downtown areas of Eversource territory. In some scenarios and percentiles within those examined in the Eversource study, the ocean has a cooling effect on Boston, mitigating the heat island effect and resulting in peaks of temperatures forecasted in smaller, inland towns in Western Massachusetts. Such heat islands are however not visible in the SHMCAP results since the state is coarsely divided into three sections only.

SHMCAP identifies demand-related concerns with a warmer climate. The Eversource study, approaching the quantification of climate change from an EDC perspective, has a high focus on climate-driven energy demand and as such elevated this to consider it a separate climate hazard. Additionally, a much broader set of EDC planning and operation practices are impacted by higher temperatures, as outlined in Section 10.5.

Wildfires can have a grave impact on T&D lines and assets; however, wildfires are an uncommon phenomenon in Massachusetts.

Invasive species are also not expected to be impactful to EDC infrastructure. An edge case could be invasive species growing around poles or manholes, potentially directly impacting pole structural health or disrupting or delaying manhole access and associated maintenance or restoration activities from the EDC. The types and growth of invasive species are related to climate change, but this hazard was not studied as part of the Company's climate science study.

In the section on extreme events, presented as a separate climate hazard in the MA report, hurricanes, Nor'easters, and tornadoes are studied. All these extreme weather types have acknowledged impacts on energy/EDC infrastructure discussed in the MA report. Tornadoes are identified as the event with the narrowest warning time. Nor'easters are the most frequently occurring natural hazard in Massachusetts, although the report does point out the potentially different year-to-year occurrence pattern due to the heavy stochasticity of these events. The report includes a graph showing the intensification of storms in the Northeast, Figure 239, by means of the precipitation due to snow and rain. The Northeast is exhibiting the highest percent increase in intensity of precipitation across the United States, where the 2001-2012 levels are 71% higher than the 1901-1960 levels. Similar results were obtained by research performed by the Company and researchers at the University of Connecticut for the New England region, as shown in the following Figure 239.

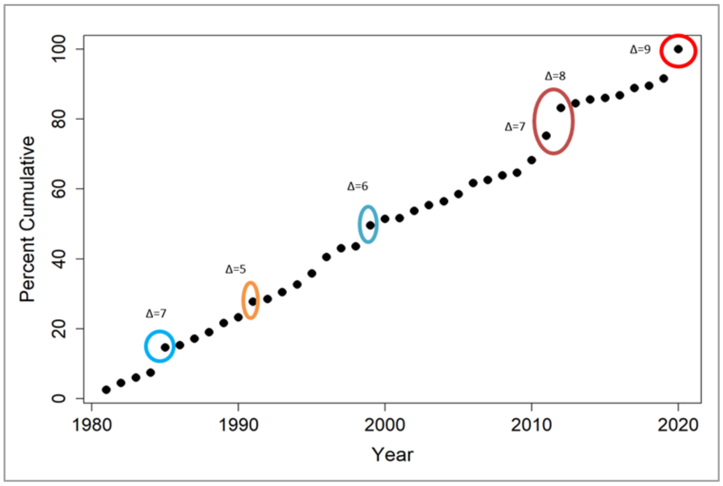


Figure 238: New England Region Cumulative Intensity of Precipitation

In SHMCAP, strong winds and thunderstorms are lumped together under the category of "Other" storms. Eversource's historical outage data indicates that winds and thunderstorms can be a non-negligible driver of outages, hence the Company is currently in the process of forecasting wind as an additional climate hazard.

SHMCAP recognizes that the restoration process of major events may be delayed due to no, limited, or difficult accessibility to outage areas because of inclement weather or blocked transportation access.

SHMCAP has a dedicated chapter on non-climate influenced hazards, that focuses on earthquakes. It is preceded by a section on technological and human-caused hazards. The next SHMCAP Section, Section 6, on the state's programs for climate mitigation and adaptation mention programs outside EDC jurisdiction and control that still influence the level of impact of climate change on the EDC infrastructure. These projects should be coordinated with the EDCs hardening plans to ensure optimality and smooth coordination.

SHMCAP also suggests that an event may have long-term consequences. For example, on page 278 of the report, the possibility of a landslide in later years due to wildfire is mentioned. Also, SHMCAP talks of consecutive phenomena where the sequence of events magnifies their individual impacts. This is well aligned with the extreme phenomena that the Company's climate study is focused on, as discussed in Section 10.4 of this filing.

Section 4 is also concerned with the frequency of occurrences of those events. Otherwise referred to as return period, this is a critical property of the events, used by EDCs, amongst other metrics, to draw the line on the probability of the events they plan against. On page 4-10, a historical analysis of 22 disasters over 63 years is summarized to an expectation of about 1 precipitation-related disaster every three years. Due to the impacts of climate change, which intensifies and increases the frequency of these events, more than 22 disasters are expected over a period of 63 years or more than 1 disaster every three years. For the same reason, some of the 433 flood events mentioned as lower intensity would repeat and intensify to a disaster.

SHMCAP also discusses warning potential and preparation headroom for each climate hazard to plan and implement emergency responses. Tornadoes are identified as the event with the narrowest warning time. For EDCs this is a critical distinction between things the EDC can do to proactively harden and provide in-event response and what the EDC needs to rely on other parties to resolve. For example, the EDCs rely on other parties to get information on potential transportation obstructions. Even assuming full and timely notifications, emergency response is typically headquartered in the EDC's AWCs making options for alternate routes more limited if not deterministic. While an EDC warning time is important and highly relevant to preparedness and pre-staging for events, it is a reactive measure. The EDCs also need to understand the types of major events expected in the long run so that they can inform their planning and appropriately harden the system with the optimal projects at targeted grid locations.

Chapter 7 of SHMCAP identifies 108 actions. Of those 108 actions, the actions involving the EDCs will be administered through DPU, DOER and EOEEA. These actions involving the EDCs span all major climate interactions studied in the report (precipitation, sea level rise, rising temperatures and extreme weather). The action titled "Build energy resiliency" should include the EDCs as partners. Collaboration between the numerous parties involved can produce fruitful results that achieve all stakeholder's goals. A recent demonstration of such collaboration is highlighted in the development of East Cambridge substation.

The action titled "Regional power grid planning and incorporation of climate change data" was listed as a medium priority action. The Company believes this should be elevated to a high priority item. As mentioned above, EDCs need to expand investments to harden the energy infrastructure way in advance as well as respond in the shorter term and during and after events, therefore such planning is critical, making the role of the regulators for approval and cost recovery also crucial.

In terms of stakeholder engagement, the Company applauds the state's efforts to increase inclusivity and collaboration and plans to uphold these efforts. To support this, the Company will be sharing the results of its climate vulnerability study online for interested stakeholders. The Company also published an updated Climate Adaptation and Mitigation Plan in 2023 that discusses similar issues at a higher level and includes sections on stakeholders and equity, etc.

Moreover, the Company is looking forward to working with the state to promote the fifth goal of the States's plan, that of increasing education and awareness. As Section 12 of this report mentions, the Company has and plans to expand its comprehensive labor and workforce development plans, focusing on training existing and new staff on the new normal for the energy sector, as well as engaging pre-college age students and getting them interested in the efforts to mitigate and adapt to climate change.

Last but not least, it is important to note that, while SHMCAP is not targeted just to EDCs, the role of the electric grid will keep becoming more and more critical for various social and economic sectors due to progressing electrification and the proliferation of distributed energy resources and the IoT.

10.2. Distribution Reliability Programs

Eversource has been implementing a variety of programs targeted at improving reliability. The following Table 75 shows the historical spending over the past four years for reliability improving programs. Negative numbers reflect credit from previous years.

Table 74: Historical Spending on Distribution Reliability Programs 2019-2022

Reliability-ED ($M)	2019	2020	2021	2022
4kV Conversion	5.3	3.4	7.6	7.3
Distribution Automation	3.4	3.4	6.1	8.2
Distribution Line Reliability	37.1	44.3	51.8	91.6
Network Reliability	1.2	0.6	18.1	15.8
Poor Performing Circuit Program	3.8	6.3	14.1	10
Reliability - Other	36.7	41.7	31.4	23.1
Split Fiber Main	7.9	0.7	-1.2	0.1
Substation Reliability	23.3	35.3	26.6	49.6
URD/DB Cable Improvements	11.3	14.3	13.4	12.5
Total	130	150	168	218

These programs are briefly described below.

- **<u>4kV Conversion:</u>** This program targets 26 4kV stations for voltage upgrade to 13.8kV. The estimated reliability benefits of upgrading 4kV to 13.8kV is close to 50%. 4kV conversion projects are multi-year projects. So far, the Company has planned the start of the 4kV replacements out to 2026 for 10 out of the 26 stations. Laterals fed off 4kV stations up for voltage conversion need to also be converted.
    - Station 292 was converted to 13.8kV in 2022
    - Stations 322, 321 and PNU 28 will be converted to 13.8kV in 2023
    - Station 293 will be converted to 13.8kV in 2024

- Stations 362 will be converted to 13.8kV in 2025
  - Stations 30, 49, 67, 59 will be converted to 13.8kV in 2026

- **Distribution Automation:** The Company engages in several efforts to increase distribution automation, including remote controls, monitoring and telemetry. A critical distribution automation program is that of Tripsavers. All overhead 65A fuses and larger are to be assessed for replacement with Tripsavers. This is typically lines with more than 5 sections. Further, additional potential locations for Tripsavers within the worst performing circuits are examined. In 2022, 497 Tripsavers were installed in MA, specifically 120 in EMA North Metro, 127 in EMA West, 150 in EMA South and 100 in WMA. Company-wide, trip savers are utilized as fuse replacements and to sectionalize laterals. The Company is also working towards a plan to install reclosers to create backbone zones of 500 customers or less.

- **Distribution Line Reliability:** The core program in this category is pole inspections and pole replacements. The Company has a proactive logic to asset replacements, including poles. As indicated in Section 4 of this report, the Company has commenced an asset health program, where the effective age of poles is calculated. The ultimate goal is to replace assets proactively based on their effective age rather than their clock age. The results of this asset health initiative for poles are shown in Chapter 4. The proactive, condition-based approach is also applied to wires.
- **Network Reliability:** This program refers to proactive replacements of network transformers and network protectors. Specific to network transformers, the Company has determined that there are 86 network transformers whose age is greater than 50 years, 41 network transformers with ages between 45 and 50 years, and another 15 transformers aged 40-45 years. Since the network transformer useful life (otherwise referred to as full depreciation period) is 45 years, the Company is implementing a network transformer replacement plan that would retire network transformers beyond their useful life in a five-year window. This would require close to 25 network transformer replacements annually. Network transformers are an asset type that the Company plans to apply the asset health calculation model to next.

  Similarly, network protectors also have close to 45 years of useful life. The Company has determined that there are 197 network protectors whose age is greater than 50 years, 102 network protectors with age between 45 and 50 years and another 29 network protectors aged 40-45 years. The Company is considering a network protector replacement plan that would soon retire assets beyond their useful life. This would require close to 30 network transformer replacements annually to replace all network transformers whose age exceeds the useful life of 45 years in about 10 years.
- **Poor Performing Circuit Program:** This program focuses on projects to improve the performance in circuits identified as poor performing. Per the Massachusetts Department of Public Utilities, a poor performing circuit is a circuit whose CKAIDI or CKAIFI values for a reporting year is amongst the highest (aka worst) 5% of all of the EDCs active circuits or feeders. A problem circuit is a circuit whose CKAIDI or CKAIFI is

amongst the highest 5% of all of the EDCs active circuits for two consecutive reporting years. A chronic circuit is a problem circuit that appears amongst the worst 5% of the EDCs active circuits for the third reporting year.

The Company maintains outage records and performs analytics to determine the circuit outage durations and frequency to compile the poor performing circuit lists, problem circuit lists and chronic circuit lists. Outage records are maintained with granularity intra-circuit, down to each protection/ isolation zone.

- **Reliability- Other:** The Company is planning targeted circuit ties in radial zones with high customer counts. The focus of the program is zones with more than 500 customers with poor reliability. The program works hand in hand with the parallel efforts of the Company to sectionalize to less than 500 customers per zone according to the Company's Engineering Standards.
- **Split Fiber Main:** Split Fiber Main (SFM) was an economical underground secondary electrical distribution system that was installed between approximately 1910 and 1960 in Boston and surrounding urban communities. This system used a tar-like insulating compound that was heated and poured into the sections of split pipe with cables installed to seal and weather-proof the cables. The split pipes were also covered with creosote-treated wood planking to protect the cables and pipes from damage from potential dig-ups in the future. While this system operated reliably for many years, as the system aged and degraded, faults began to occur and became more common. Electrical faults in this system created gases by the pyrolysis of SFM components, which could escape to soil, sewers, underground conduits and into service pipes leading into homes and businesses. This program was implemented to remove all SFM on the Eversource System and as of the end of 2022, all known SFM has been removed.
- Substation Reliability: Substation Reliability is a set of programs that address and replace obsolete substation equipment that has reached the end of its useful life, ex. Breakers, reclosers, reactors, relays, transformers, switchgear, Motor Operated Disconnects, fencing, ground grid, and annunciators. It also includes new substations, switchgear, monitoring, and other equipment needed to improve substation or distribution system reliability. For instance, the Transformer Reliability program addresses the proactive replacement of aging/unhealthy substation transformers and installing additional transformation at substations with future capacity needs based on forecasted load growth. The mobile transformer fleet is also maintained under this initiative. The Switchgear Replacement Program will address replacing or refurbishing obsolete (typically >50 years old) metal clad switchgear that has reached the end of its useful life, has structural and operational deficiencies, increased maintenance, and/or lacks spare parts. This work is prioritized by switchgear condition, design, and impact to customers of a switchgear failure.
- URD/DB Cable Replacements: This program relates to underground cable and direct buried cable replacements. The Company is focused on proactively replacing underground cable. To this end, the Company is engaging in a very-low frequency (VLF) testing technology to proactively identify and repair potential faults in underground

cables. The process is performed on feeders with 3 or more faults per year, prioritized based on historical frequency of outages. The VLF test is performed (feeder de-energization is required prior to testing and one feeder is tested at a time) and the cable sections and splices that are failing are replaced.

The Company currently engages in an underground switch replacement program. The overarching goal of this program is to have all oil switches replaced by the end of 2026. In EMA, 388 underground oil switches will be replaced. Also, the Company is targeting the replacement of all Elastimold switches by end of 2023.

10.3. Distribution Resiliency Hardening Programs

10.3.1. Data-Analytics Based Resilience Plan

New England has already started seeing the impacts of climate change through the increased frequency and intensity of storm events resulting in elevated all-in SAIDI and all-in CMI[1]. New England was hit by three catastrophic hurricanes since 2010 – Isaias, Sandy and Irene. New England was also subjected to Winter Storm Alfred – also coined the 2011 Halloween Nor'easter arrived just two months after Irene. When looking at 40 years of Storm data, these storms range between 1 in 30- to 50-year events. But shortening the lookback period to more recent 15 years of Storm data, suggests a dramatic compression in catastrophic storm probabilities in the range of 1 in 19- to 23-year events. This substantial compression in storm probabilities when looking at more recent storm history demonstrates that these catastrophic storms are becoming significantly more likely in New England. Increasing transportation and building electrification, the proliferation of renewables and distributed energy resources as well as of the IoT, place the electric grid at the epicenter of various social and economic sectors. As a result, effective EDC resilience planning to enable the grid to withstand outages and reduce the impacts of unavoidable events has become increasingly critical.
This section describes Eversource's current data-driven approach to resilience planning. Chapter 10.5 outlines changes envisioned to this planning process after considering the results of the climate vulnerability study.

The purpose of Eversource's resilience methodology is three-fold:

- Implement a step-change in grid resilience in the state of Massachusetts by proactively hardening the system with cost-optimal, highly targeted projects, making use of its highly granular outage data, and
- Ensure resilience projects result in benefits to Massachusetts' Environmental Justice[2] communities and quantify said benefits
- Create a streamlined, robust, and repeatable planning process that is capable of periodically intaking new outage and circuit data to reflect recent changes.

In Eversource's outage data, each outage event is assigned to an operating device, which is the most upstream (close to feeder head) isolation or protection device that remains open on a sustained outage to isolate the fault (e.g., fuse, switch, circuit breaker, recloser). When a fault occurs, the directly upstream protection device would trip to interrupt fault current. If there are isolation devices downstream, the one directly upstream of the fault will be opened to isolate the fault. At this point, the protection device can reclose. The customers between the protection and isolation device are restored. The operating device is the isolation device. Absent circuit ties or local generation, all customers downstream of the operating device will be interrupted and will continue to be on outage until restoration. The part of the circuit that is between two isolation/ protection devices can be defined as a zone. The following Figure 240 visualizes the protection and isolation processes described above in a zoomed-in part of a distribution circuit.

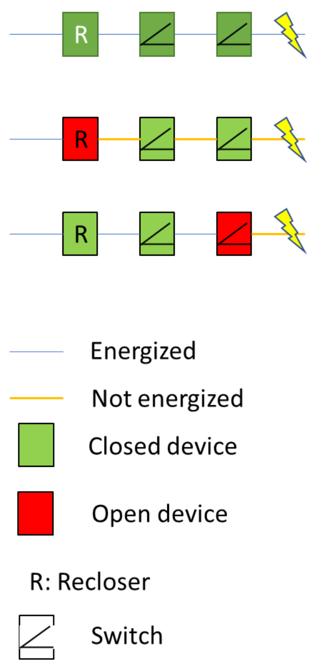


Figure 239: Protection and Isolation Processes a Simplified Part of a Distribution Circuit.

The first important element is targeting actionable grid vulnerabilities. In other words, Eversource's resilience methodology scans the entire system for outage locations and vulnerabilities and focuses specifically on high criticality outages, meaning outages with many customers impacted, long duration outages and multiple outages at the same zone (chronic problems). This comprehensive system scan enables a resilience program that targets high-yield projects first rather than across-the-board, generic, state-wide program implementation. This is based on advanced data analytics using Eversource's highly granular outage data. Emphasizing proactive system hardening has benefits in storm response and restoration, the innately reactive part of resilience.

The second element of Eversource's methodology is data engineering to understand which attributes of outages and of the circuits are important to assign optimal projects. For example, looking at major events, tree-related events dwarf all other outage causes. This means that classifications based on outage cause will not create result variability or in other words, cause codes are not an attribute that can drive decisions on the optimality of resilience solutions.

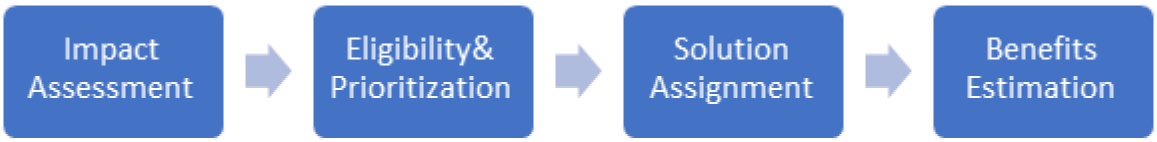


Figure 240: Process Used to Quantify Project Benefits

10.3.1.1 Historical Outage Data

The Company has investigated the outage data during major storms in the past four years (2019-2022). In Eversource's Massachusetts territory, between 2019 and 2022, approximately 1.52B Customer Minutes of Interruption (CMI) are accumulated during Major Exception Days.

Eversource's methodology prioritizes the highest criticality events as actionable events including events with lots of customers impacted, long duration events, and multiple events in the same zone (chronic problems). The most common case of such events are events happening close to the feeder head. Absent circuit ties or local generation, events close to the feeder head result in all downstream customers (a high percentage of the circuit's total customers) being interrupted and remaining on outage until the outage is restored. Such events are more common, where the operating device is a recloser or circuit breaker. In the Massachusetts 2019-2022 major event data, 472M CMI or 31% of the total major event related CMI were on reclosers and breakers. The number of events and CMI during major exception days per year are shown in the following Table 76 narrows this down to the same data where the operating device is a recloser or a breaker.

Table 75: Historical Data from Outages (2019-2022)

Years	Number of Major Events	Total Customer Minutes of Interruption (CMI)	Total Customers Affected (CI)
2019	5,318	284,920,828	519,587
2020	6,640	244,324,968	596,606
2021	6,079	801,862,674	525,732
2022	2,990	188,106,462	412,293
Grand Total	**21,027**	**1,519,214,932**	**2,054,218**

Table 76: Historical Data from recloser Showing Major Outages (2019-2022)

Row Labels	Number of Major Events	Total Customer Minutes of Interruption (CMI)	Total Customers Affected (CI)
2019	308	72,381,992	191,694
2020	468	65,895,578	236,693
2021	277	245,258,408	189,690
2022	269	88,625,603	219,015
Grand Total	**1,322**	**472,161,581**	**837,092**

As the Tables 76 and 77 above show, the average impact of each event (i.e., per event CMI) when looking at the entire system is much lower than the average impact of each recloser or breaker event to CMI. This validates that the logic of focusing on recloser, and breaker events aligns with focusing on high criticality events – or events that result in long duration customer outages.

10.3.1.2 Eligibility Criteria

The 1,322 recloser and breaker-related major events, shown in

Table 76 above, occur on 912 unique zones. Emphasis is placed on the zones with high criticality; either those with multiple events (chronic problems/ repeat offenders) or those with high CMI impacts per event. Filtering to zones with more than 2 events per zone or more than 1,000,000 average CMI per event, the resilience program focuses on 318 zones.

10.3.1.3 Solutions Planning

The Company's resilience plan is using the following rules-based approach to pair resilience projects to those 318 critical impacted zones. As mentioned above, the portfolio of resilience solutions considered are: (i) undergrounding, (ii) aerial cable, (iii) reconductoring to tree wire or spacer cable and (iv) resilience tree work.

Impacted zones are bucketized in three categories or tiers of criticality:

1) First tier is made up of impacted zones with 300,000 CMI per event on average or more
2) Second tier is made up of impacted zones with 150,000 CMI per event on average or more (but less than 300,000 CMI per event)
3) Third tier includes impacted zones with less than 150,000 average CMI per event.

The rules are as follows, also shown visually in the table below.

- First tier zones -> Undergrounding

- Second tier zones -> Aerial cable
- Third tier zones
    - With bare wire -> Reconductoring to tree wire or spacer cable
    - Insulated wire -> Resilience Vegetation Work

The logic of the rules is to pair the highest criticality items with the highest impact solutions. The impact of resilience mitigation is quantified as the impact on the all-in SAIDI. Table 77 below shows the percent SAIDI improvements and per mile costs of each resilience mitigation. These estimates align with industry and literature standards and with currently available Company actuals. Spatial differences (e.g., accessibility and constructability) that can cause costs to vary upwards or downwards potentially significantly are not considered here in this system-scanning exercise.

Table 77: Percent SAIDI Improvements and Per Mile Costs of Resilience Mitigations

Measure	All-in SAIDI Improvement	Cost ($M/mile)
Undergrounding	98%	4.0
Aerial Cable	82%	2.2
Reconductoring (other)	50%	1.1
ETT/ETR	35%	0.1

Undergrounding distribution lines remove all interactions with vegetation and most interactions of electrical assets with weather elements and as such has the highest percentage of SAIDI improvement. This solution has the highest cost amongst the portfolio solutions and is assigned to the most critical grid vulnerabilities with an average of 300,000 CMI per event or more.

Aerial cable also offers high performance improvements, albeit still overhead and with exposure to vegetation and weather elements. Aerial cable comes at approximately 50% less cost than undergrounding, hence is paired with the second highest criticality tier, zones with 150,000 average CMI per event or more.

Reconductoring to tree wire or spacer cable is a hardening solution for those systems that are now utilizing bare wire. Their reliability benefits are lower than underground and aerial at a lower cost per mile.

Resilience tree work is the cheapest solution and can be thought of as the only solution within the mentioned portfolio of solutions that aims at mitigating the cause rather than adapting and hedging against it. Removing hazard trees and trimming to higher than usual clearances has limited reliability benefits compared to the other solutions and is assigned as a resilience solution for last-tier criticality zones that have covered wires already, hence reconductoring to tree or spacer would not constitute a hardening upgrade.

The following flowchart in Figure 242 visualizes the rule-based approach described above.

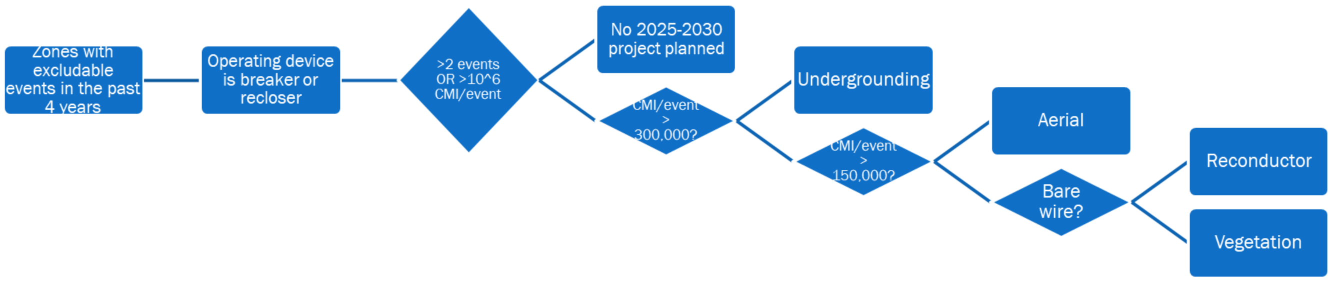


Figure 241: Rules-Based Approach to Solutions Planning Process

10.3.1.4 Results of the Proposed Methodology

Applying this rule-based methodology to Massachusetts major event outage data results in a 21% reduction of all-in SAIDI with projects on 318 zones. Since the focus was on high criticality events, the methodology is expected to result in high undergrounding percentages. Specifically, 49% of the zones or 155 zones are paired with undergrounding. Reconductoring to tree wire or spacer cable is paired with 19% of the zones or 60 zones and is the second most numerous solution type proposed. Vegetation and aerial cable tie in third place with 16% of the projects or approximately 50 zones each.

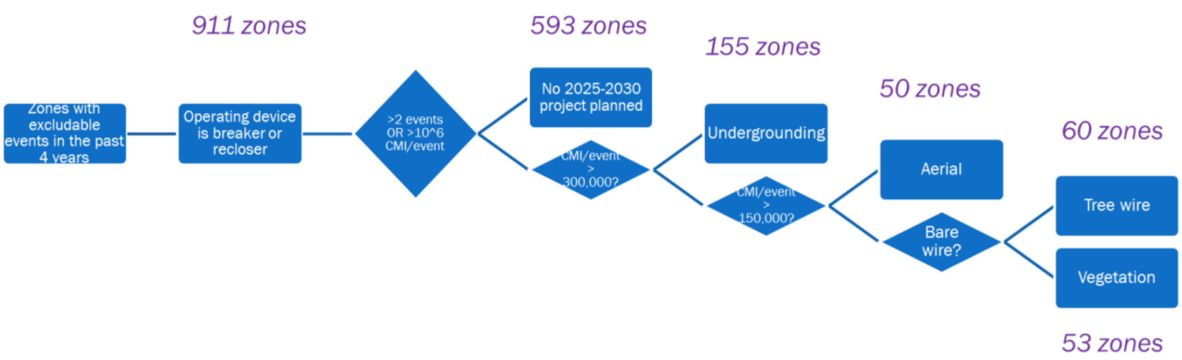


Figure 242: Rules-Based Approach to Solutions Planning Process with Zones

EVERSOURCE

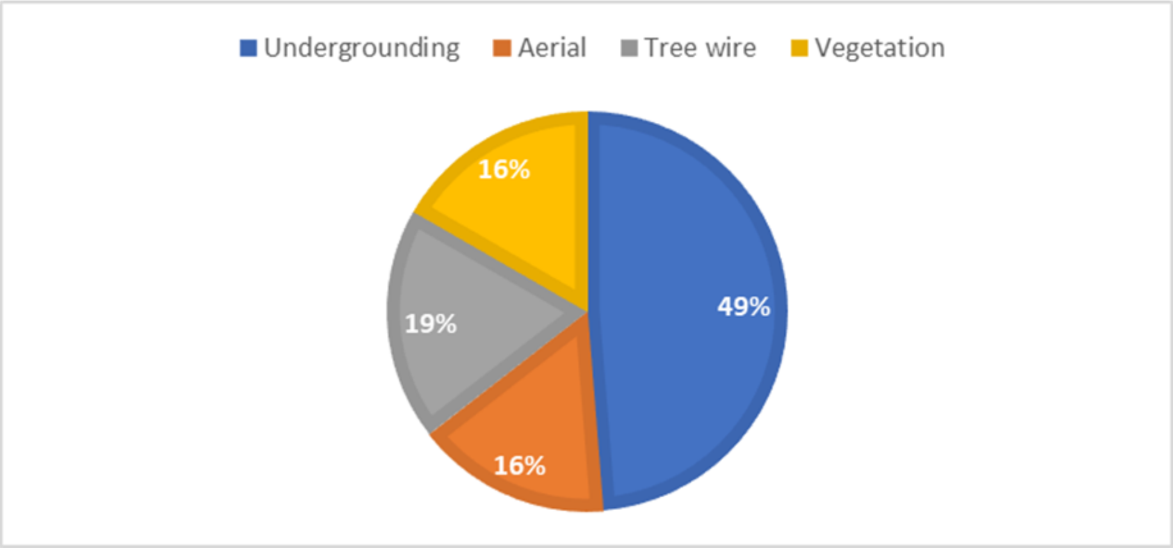


Figure 243: Breakdown of Resilience Projects across Eversource Service Territory

The State's Hazard Assessment and Mitigation Plan, discussed in Section 10.1, places emphasis on the affected communities for each climate hazard.

The results can further be broken down into specific regions; the following Figure 245 show the breakdown of the resilience projects per region. In EMA-North Metro Boston, there are only 9 recloser and breaker zones in the project list. This is expected, due to the high undergrounding present already in this region. In EMA-South, 66% of the zones are paired with undergrounding. This is expected as events in this region are typically high impact SAIDI-wise, due to the system being on the edge of the territory, overhead and mostly radial. Higher percentages of vegetation and reconductoring to tree wire or spacer in EMA-North Metro West and WMA are due to the nature of the outages in these regions being less impactful SAIDI-wise.

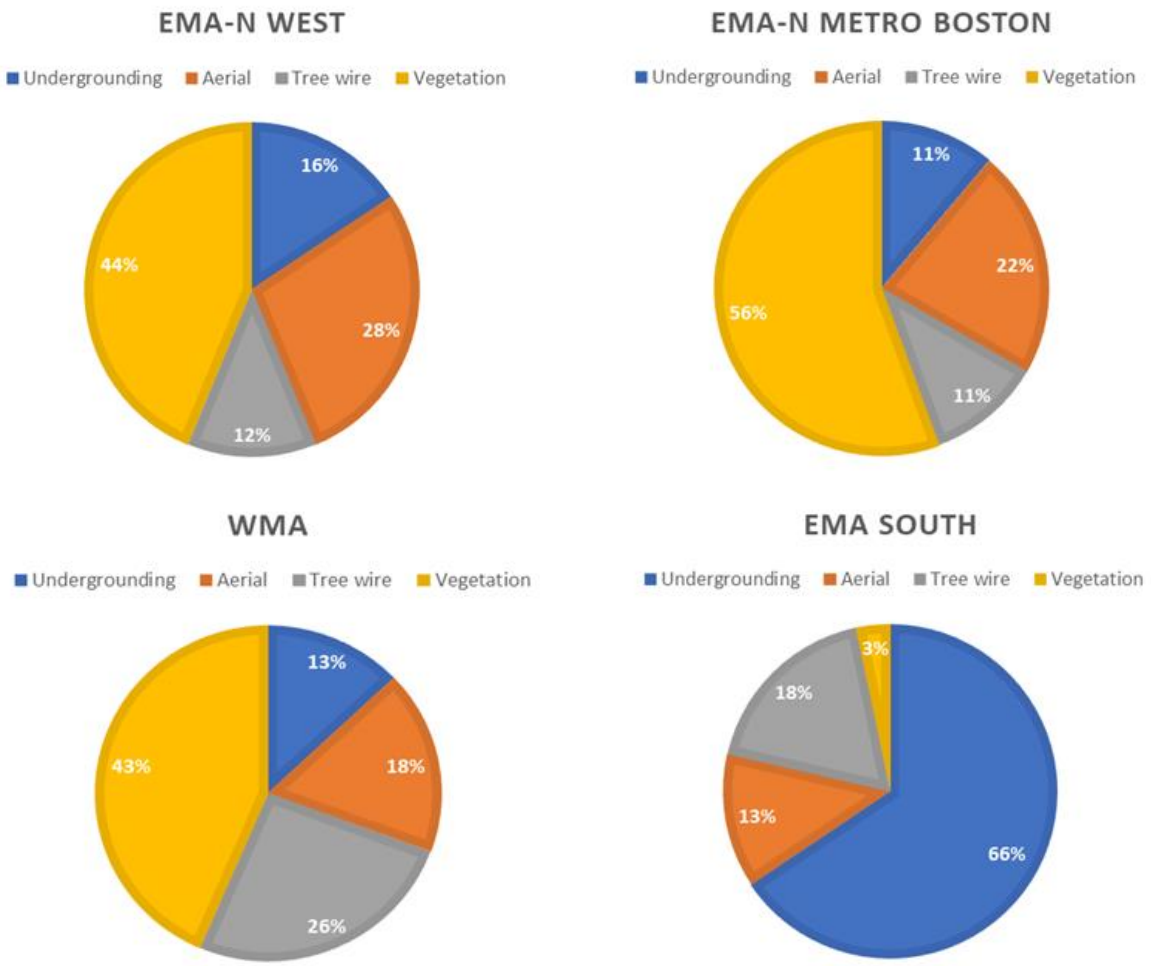


Figure 244: (a-d) Breakdown of Resilience projects by Region

10.3.1.5 Optimal Investment Saturation Point

As a last step, the Eversource resilience methodology considers the optimal investment saturation point for resilience work considering diminishing returns, already a consideration in reliability planning. The 318 resilience projects are ranked based on the delta SAIDI they provide. This metric of delta SAIDI per project can be used to understand the declining rate of SAIDI improvement. The following Figure 246 shows the delta SAIDI on the vertical axis plotted against the running resilience program cost on the horizontal axis. The cutoff point is set as the point where the slope of the curve declines. For this case, the cutoff point is pegged at $450M (red dashed vertical line).

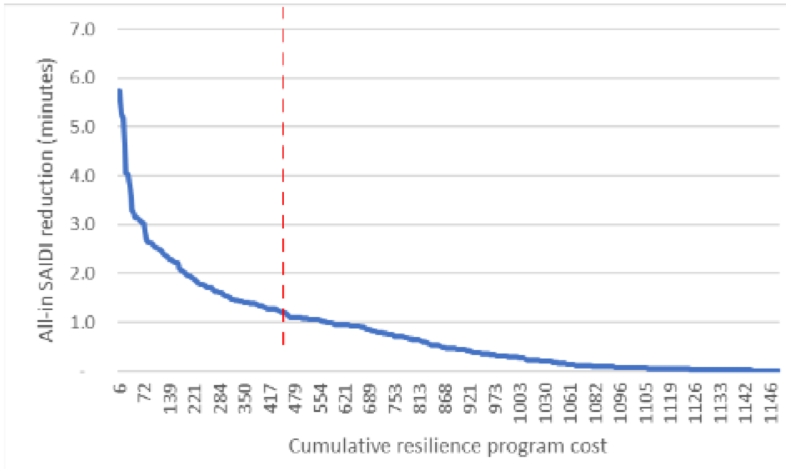


Figure 245: All-in SAIDI Reduction Relative to Resilience Program Costs

The following Figure 247 shows the major event SAIDI on the vertical axis plotted against the running resilience program cost on the horizontal axis. With a $450M 10-year resilience program budget, the SAIDI benefits would reach 14% reduction of all-in SAIDI. In other words, for 39% of the total cost of the 318 projects, Eversource achieves 65% of the SAIDI benefits. The prioritization of this plan will consider the circuit zones that drive the most improvement with majority of customers serves in Environmental Justice communities.

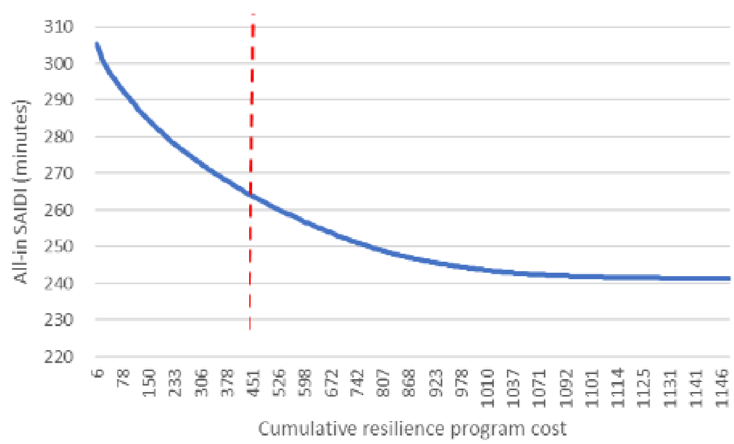


Figure 246: All-in SAIDI relative to resilience program costs, in descending order of higher SAIDI reduction benefits.

10.3.2. Provincetown BESS microgrid

One of the Company's largest recent investments in resilience is the battery energy storage-based microgrid in Provincetown. Faced with the need to provide a backup supply solution to the outer Cape Cod area, the traditional solution would have been to build an additional 13-mile distribution line from Wellfleet to Provincetown. This would have required construction through a substantial portion of the Cape Cod National Seashore with potential environmental impacts and significant cost for customers. As an alternative, Eversource chose to construct a

24.9 MW/38 MWh lithium-ion battery system as the sole source of supply for a microgrid back to the Wellfleet substation. The microgrid was specially designed to size the microgrid island to maximize reliability benefit to customers based on damage location and can back up 5,700 customers. When not required for reliability purposes, the BESS can be used for peak shaving and local voltage support.

Eversource overcame challenges related to technology, design, and testing by collaborating across disciplines as well as with local officials and leveraging diverse skill sets with a problem-solving culture focused on continuous learning over the course of the four-year project. This ground-breaking project is expected to improve reliability for approximately 11,000 customers with automatic restoration of customers in less than one minute. Eversource was recently awarded the 2022 Achievement Award from the Association of the Edison Illuminating Companies for this project.

10.3.3. Substation Elevation

The Company's Standards include directions on substation elevation. These are applicable to existing or new substations in flood-prone areas or coastal areas susceptible to sea level rise. Substation elevation and grading are designed with the goal for the substation to be operational under flood conditions.

The threshold used to determine elevations is the Base Flooding Elevation (BFE) which covers elevation of flooding, including wave height, that has a 1% (1 in 100 years) chance of being equaled or exceeded in any given year as depicted on FEMA's (Federal Emergency Management Agency) Flood Insurance Rate Map (FIRM).

Each critical equipment type can have a specific elevation minimum. New substations are held to higher elevation standards than existing substations. The elevation standards are higher for substations in coastal zones as defined by FEMA. The least stringent elevation standard is for existing substations not in FEMA-defined coastal areas, where the elevation minimum is the BFE.

10.4. Asset Climate Vulnerability Assessment (such as Flood Impacts, Wind Speeds, High Heat Impacts, Ice Accretion, Wildfire and Drought)

The Company has commissioned a climate change vulnerability study covering its tri-state territory (New Hampshire, Massachusetts and Connecticut). As the blue-sky and all-in performance numbers shown in Section 4 above reveal, major storms are already a critical and growing contributor to the overall customer experience. While the impacts of climate change are quantified through the all-in performance metrics shown in Section 4 above, Eversource's climate change vulnerability study aimed at formally quantifying the cause itself.

The quantification of climate change was done through a comprehensive portfolio of forecasted climate science variables that allow us a broad and in-depth description of each climate hazard (temperature, precipitation, sea level rise, and storm surge) through multiple different angles. The following table lists the variables that were forecasted. For example, as the Table below shows, there are 11 different variables utilized to describe the expectation around temperatures. The list also includes indirect effects, like for example the impacts of temperature changes to demand.

Table 78: Climate Hazards and Climate Variables Studied as Part of Eversource's Climate Vulnerability Study.

Hazard	Climate Variables
Extreme Temperature	1. Annual 50th, 90th and 95th percentile daily maximum temperature 2. Annual 5th, 10th, 50th, 90th and 95th percentile daily average temperature 3. Number of days above 90th and 95th percentile daily maximum temperature 4. Number of days above 90th and 95th percentile daily average temperature 5. Frequency of two and three consecutive day heat waves with daily maximum temperature over 90th and 95th percentiles 6. Frequency of two and three consecutive day heat waves with daily average temperature over 90th and 95th percentiles 7. Annual longest heat wave duration over 95th percentile daily maximum temperature 8. Annual longest heat wave duration over 95th percentile daily average temperature 9. Number of days below 5th and 10th percentile daily minimum temperature 10. Annual warmest daily maximum temperature 11. Annual coldest daily minimum temperature
Energy Demand	12. Proxy for May-September Weighted Temperature-Humidity Index (WTHI) 13. October-April Heating Degree Days 14. May-September Cooling Degree Days
Heavy Precipitation	15. Annual maximum 1- and 5-day precipitation 16. Days per year with precipitation exceeding 1, 2, and 3 inches
Drought	17. Annual maximum consecutive dry days
Sea Level Rise	18. Local sea level rise projections under low and high scenarios 19. Sea level rise flooding depth and extent under low and high scenarios
Storm surge	20. Category 1, 2, and 3 hurricane storm surge depth and extent

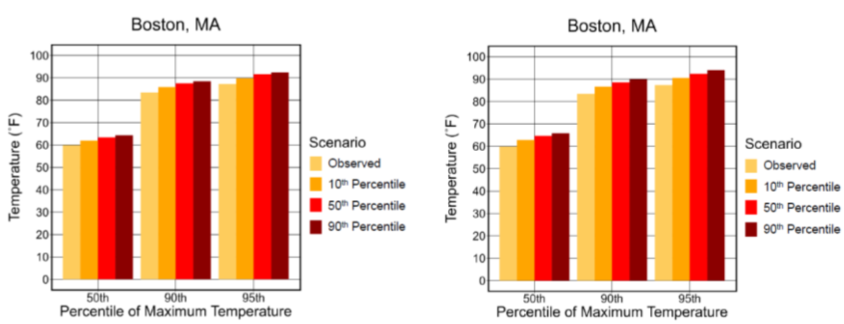
The results of global science models are typically coarse. LOCA2 (Localized Constructed Analogs version 2) CMIP6 (Downscaled Coupled Model Intercomparison Phase 6) datasets downscale results to a granular 6km by 6km grid using to ensure localized issues can properly showcased and addressed. These statistical downscaling models are refreshed periodically; the Company is the first EDC to use their latest version.

Two climate change scenarios were used for the forecasts; the Shared Socioeconomic Pathways (SPP) 2-4.5 and SSP5-8.5. Projections use a common set of 23 LOCA Global Science Models across SSP2-4.5 and SSP5-8.5. The former assumes that at a federal level GHG emissions stay at current levels until 2050 and that start to reduce, but not reaching net zero by 2100. The former (SSP5-8.5) assumes GHG emissions keep increasing and triple by 2075. The forecasts extend out to 2080 with intermediate steps for 2030, 2040 and 2050.

The results for each variable at each timepoint are probability distributions of the forecasted variables, one for each GHG scenario. The Company's study includes calculation of 10th, 25th, 50th, 75th and 90th percentiles for each SPP scenario and each variable. Mathematically, 90th percentile represents the right tail of the probability distributions, where 90% of the samples have a lower value. The 90th percentile of the SSP5-8.5 is highlighted in the upcoming results, as it represents a worst case or a perceived ceiling of the forecast. The results also highlight the 50th percentile of SPP2-4.5, as a more middle-of-the-way scenario to contrast with that worst case. The 50th percentile represents a value that is higher than 50% of the samples.

The climate study concludes that a warming climate should be expected. Quantifying this by temperature, both the average and maximum annual temperature will increase. Specifically, the upper tail of the daily maximum temperature will increase by 3.6F to 6.7F in Boston by 2050 and the upper tail of the daily average temperature will increase by 3.7F to 7.7F in Boston by 2050. Because both the average and maximum temperature are expected to increase, the blue-sky days' performance will be altered too.

The following graphs shows the warming climate by means of how hotter weather today, for example the 90th percentile of the daily maximum temperature, becomes less of a rarity in the new normal of a warmer climate and constitutes a lower percentile by 2050 under both climate science scenarios.



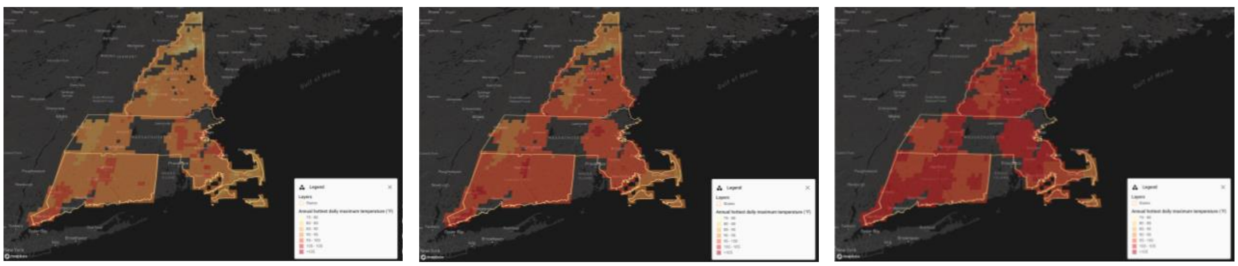
SSP2-4.5 SSP5-8.5

Figure 247: Daily Maximum Temperature in Boston under SSP2-4.5 and SSP2-8.5 Climate Scenarios

The following tri-fold figures are organized as follows: from left to right the historically observed values of the variable, the forecasted value under SSP2-4.5 50th percentile for 2050 and the forecasted value under SPP5-8.5 90th percentile for 2050.

The two-fold pictures show the evolution of a variable across time (years are on the horizontal axis), with SSP2-4.5 shown on the left and SPP5-8.5 shown on the right. The different percentiles within each scenario are plotted in the same graph for comparison.

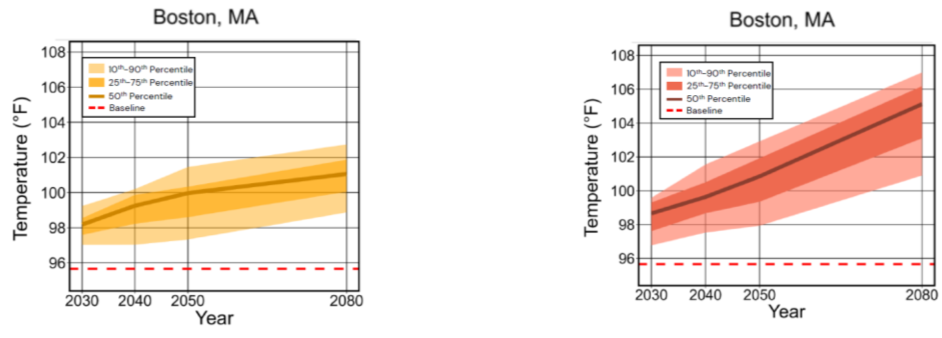
Error! Reference source not found. shows the annual hottest daily temperature. Both SSP2-4.5 50th percentile and SPP5-8.5 90th percentile show the warming impacts in all of the Company's Massachusetts territory. Under SSP2-4.5 50th percentile, Western Massachusetts, most of Cape Cod and the Islands have a similar annual hottest daily temperature to today's values. Under SPP5-8.5 90th percentile it is only the Outer Cape area and the Islands that have a similar annual hottest daily temperature to today's values, while all other Massachusetts areas warm up significantly.



Historical Observed | SSP2-4.5 50th percentile | SPP5-8.5 90th percentile

Figure 248: Annual Hottest Daily Temperature in 2050 Across Service Territory

A view across time of the same variable (annual hottest daily temperature) for Boston is provided in the figure below. Both emission scenarios show a progressive increase of the annual hottest daily temperature from 2030 to 2080. Under SSP2-4.5, the 50th percentile of the annual hottest daily temperature in Boston in 2050 is expected to be 100F, while under SSP5-8.5 the 90th percentile of the annual hottest daily temperature in Boston in 2050 is expected to be 102.9F.

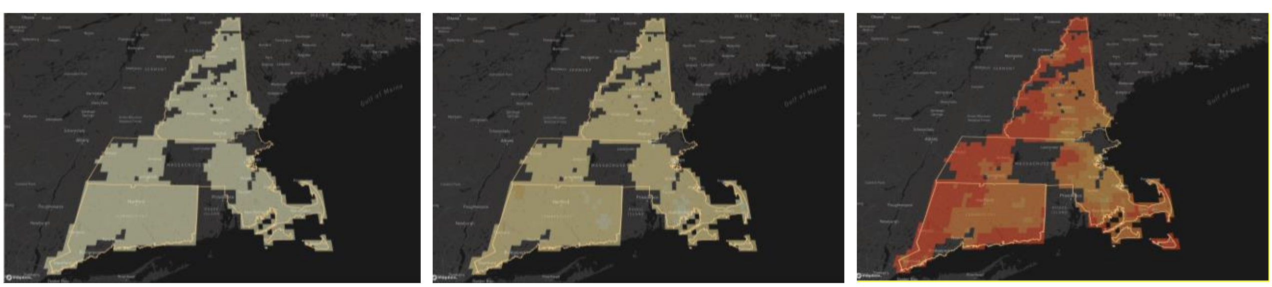


SSP2-4.5

SSP5-8.5

Figure 249: Projected Annual Hottest Daily Temperature for Boston 2030-2080

Another way to quantify the warming climate is through the duration and frequency of heat waves; the Company expects about 5 to 7 heat waves annually by 2050, while the current baseline is 2.2 heat waves annually. Heat waves are expected to be prolonged by 3.4 to as much as 20.4 more days by 2050. Summer demand will increase significantly as a result; cooling degree days are expected to increase by 200 to 974 by 2050 and the Weighted Temperature Humidity Index is projected to increase by 3.1 to 6.3 by 2050 in Boston. On the other hand, the warming climate also creates the expectation that cold extremes will become less intense and less frequent causing the associated heating loads to decline by 2050. **Error! Reference source not found.** shows the annual longest heat wave, defined as the number of days with temperatures above 95th percentile of daily maximum temperature. Under SSP2-4.5 50th percentile, the duration of the annual longest heat wave is expected to be 7.8-15.0 days in 2050, about double from the current 4.4-7 days. Under SPP5-8.5 90th percentile, the annual longest heat wave is forecasted to be 11.7-27.7 days long in 2050, from the current 4.4-7 days.

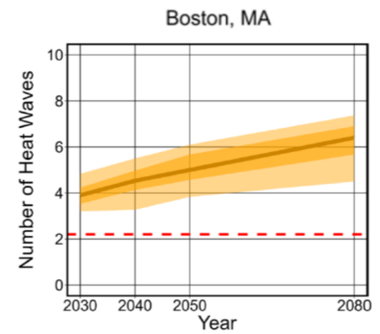


Historical Observed | SSP2-4.5 50th percentile | SPP5-8.5 90th percentile

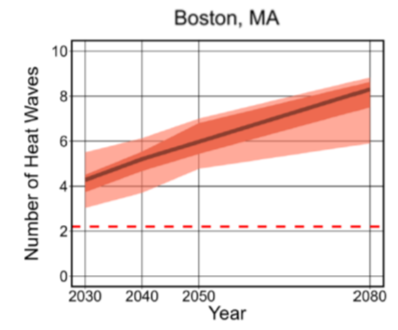
Figure 250: Annal Heat Waves in 2050 across Service Territory

A view across time of the number of the 3-day heat waves for Boston is provided in the Figure 252 below. Both emission scenarios show a progressive increase of the number of 3-day heat waves from 2030 to 2080. Under SSP2-4.5, the 50th percentile of the number of the 3-day heat waves for Boston in 2050 is expected to be 5 3-day long heat waves, while under SSP5-8.5 the

90th percentile of the 3-day heat waves for Boston in 2050 is expected to be 7 3-day long heat waves.



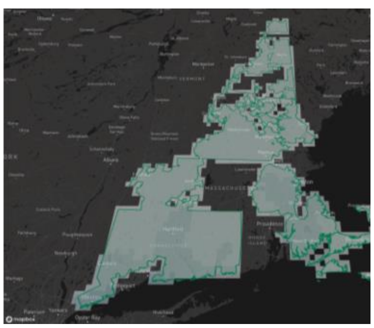
SSP2-4.5



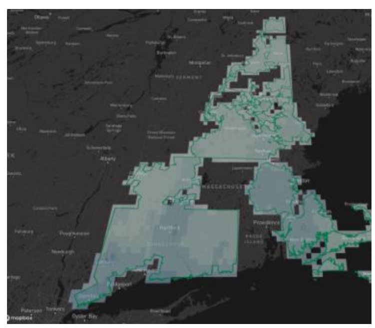
SSP5-8.5

Figure 251: Three Day Heat Waves in Boston 2030-2080

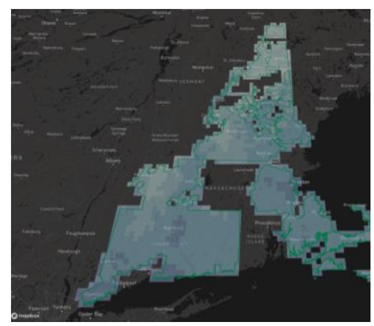
Another means to quantify the expected warming climate is done by means of showing cooling days in the summer months (May-September) and the heating degree days from October to April, shown in Figure 253 and Figure 254 below.



Historical Observed

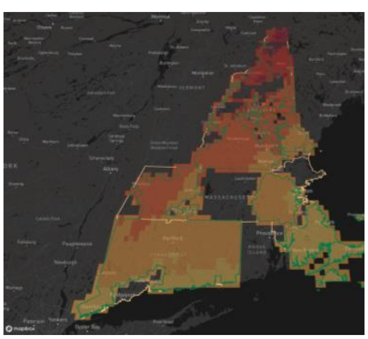


SSP2-4.5 50th percentile

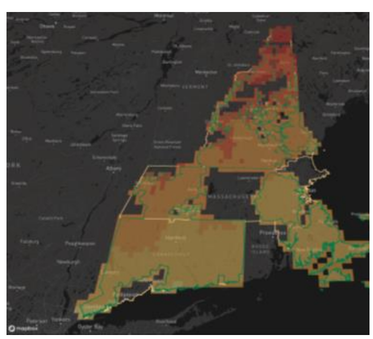


SPP5-8.5 90th percentile

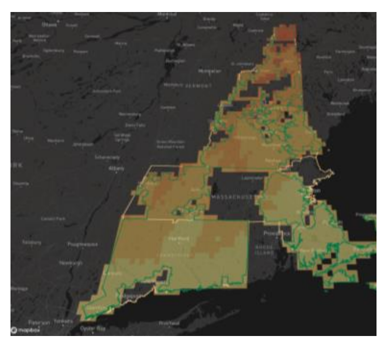
Figure 252: Cooling Days from May to September across Service Territory



Historical Observed



SSP2-4.5 50th percentile



SPP5-8.5 90th percentile

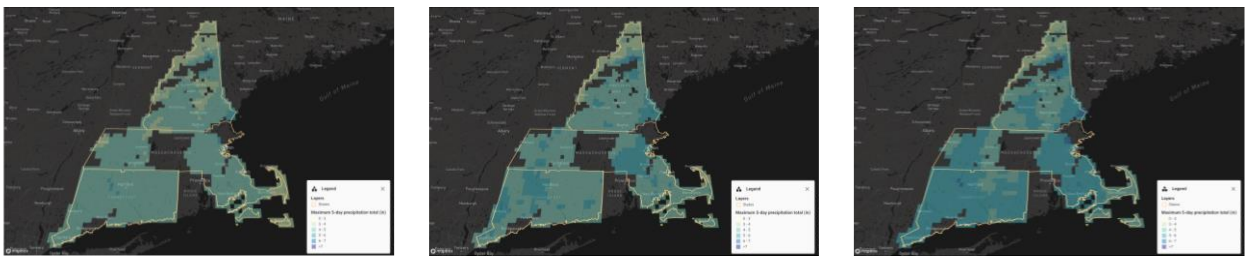
Figure 253: Heating Degree Days from October to April across Service Territory

The following Table 80 shows the summer maximum Weighted Temperature Humidity Index (WTHI) for Boston in 2050.

Table 79: Summer Maximum Weighted Temperature Humidity Index (WTHI) forecasts, Boston, 2050

		SSP2-4.5			SSP5-8.5		
Relative Humidity	Baseline WTHI	10th Percentile	50th Percentile	90th Percentile	10th Percentile	50th Percentile	90th Percentile
50%	83.5	85.0	86.6	88.2	85.5	87.4	88.9
60%	85.1	86.6	88.2	89.9	87.1	89.0	90.6
75%	87.2	88.7	90.3	92.0	89.2	91.1	92.7
90%	88.9	90.5	92.1	93.8	90.9	92.9	94.5

The following Figure 255 shows the 5-day maximum precipitation. Both the results of SSP2-4.5 50th percentile and of SPP5-8.5 90th percentile results reveal progressively worsening and spreading high precipitation.



Historical Observed   SSP2-4.5 50th percentile   SPP5-8.5 90th percentile

Figure 254: Five-Day Maximum Precipitation Across Service Territory

In order to improve the resilience hardening programs, in terms of targeting work to vulnerable areas of the, the assessment of the climate vulnerability should include a forecasting of extreme events. This assessment is typically outside the capabilities of current climate science models.

As part of this study, Eversource examined historical extreme events across its' service territory from 1960 to 2020 for ice storms and 1938 to 2020 for tropical cyclones and based on this history and the forecasted climate change results, formulated two types of plausible major events (also referred to as High Impact Low Probability (HILP) events).

The first event type is a major ice storm followed by a cold snap. Specifically, extrapolating based on historical data, a 2-day ice storm creates an assumed accumulation of 0.5-3 inches of snow in Massachusetts, with about 1.5-3 inches in Boston and about 0.5-1 inch in the Berkshires. The wind gusts are 45mph in Springfield and 60mph in Boston. The preceding cold snap after the ice storm lasts one week and pushes lowest minimum temperatures to -5F in Boston, -15F in Springfield, and to -30F in the Berkshires, while the Cape Cod area minimum temperatures stay above 0F. While a warming climate is predicted, climate change does not preclude the occurrence of cold snaps, particularly through the medium-term. Some evidence shows that complex processes amplified by climate change could worsen some cold snaps, such as polar vortex events. Models also project decreasing frequency (or likelihood) of ice storms, but ice accumulation during the highest-intensity storms could increase.

The second type of major event is a prolonged drought followed by a tropical storm. In this major event, New England experiences a 5-year drought, identified as a 5-year stretch where 75% of the months of each year have less than average precipitation. The drought is exacerbated by multiple prolonged heat waves, during which the daily maximum temperatures peak at around 102F and remain over 95F for seven consecutive days. At the end of the 5-year period and after a 20-day long heat wave, a Category 3 tropical storm makes landfall in Hartford and Western Massachusetts. These sequential phenomena are expected to have compounding effects, resulting in a dire impact on tree health. This type of event is extremely relevant to Eversource territories that have overhead systems exposed to nearby vegetation.

The exact path of these events is hard to estimate, as is the return period of these events. As next steps, Eversource plans to pair forecasted major events with a Monte Carlo simulation for their paths and simulate them with an Outage Prediction Model to measure impact on electric assets.

10.5. Framework to address Climate Vulnerability risks through Resilience Plans

As Section 10.2 indicated, the Company is utilizing its historical records of recent outages during major storms/ resilience events to compile a list of grid vulnerabilities that are the targets of the Company's resilience projects.

The Company plans to utilize the results of the climate change vulnerability study to expand its target set of grid vulnerabilities. Specifically, the geographically granular results can reveal new areas where climate hazards peak (for example where temperature will be the highest (daily maximum or average) or where the highest precipitation is expected). These locations of the peaks of the expected forecasts are going to be the new targets of resilience work upcoming. The timing of the need will also be factored in the pairing of the solution with an appropriate resilience project.

Based on the heat maps shown in the sections above, the following Table 81 shows the Division and Area Work Center (AWC) most impacted by each climate variable (i.e., where the peak of each climate variable is expected to occur).

Table 80: Most Impacted Division per climate Hazard for each Scenario.

Climate Hazard	Variable	Division/ AWC of variable peak (2050, 50th percentile SSP2-4.5)	Division/ AWC of variable peak (2050, 90th percentile SSP5-8.5)
Extreme Temperature	Annual Hottest Daily Maximum Temperature	EMA North-West/ Southborough	EMA North Metro Boston/ All EMA North-West/ All EMA South/ Plymouth EMA South/ New Bedford WMA/ Hadley WMA/ East Springfield
Energy Demand	May – September Cooling Degree Days	-	EMA North Metro Boston/ All EMA North-West/ Southborough EMA North-West/ Waltham
Precipitation	Maximum 5-day Precipitation Total	EMA North Metro Boston/ All EMA North-West/ All	EMA North Metro Boston/ All EMA North-West/ All EMA South/ Plymouth EMA South/ New Bedford WMA/ All
Drought	N/A	N/A	N/A
Sea Level Rise	Sea Level Rise	EMA North Metro Boston/ All EMA South/ Plymouth EMA South/ Yarmouth	EMA North Metro Boston/ All EMA South/ Plymouth EMA South/ Yarmouth
Storm Surge	Storm Surge	EMA North Metro Boston/ All EMA South/ Plymouth EMA South/ Yarmouth	

The critical last step in resilience planning is to pair grid vulnerabilities with the optimal resilience project based on the type of climate science variable that mostly affects the area. The Company has compiled the following causation and affect Table 82 to qualitatively associate climate hazards to grid asset types and to potential mitigations.

Table 81: Associations of Climate Hazards with Affected Asset Types and Potential Mitigations.

Climate Hazard	Affected Asset Type	Potential Mitigations
Extreme Temperature	Transformers Conductors	Upsizing equipment (higher ampacity or nameplate capacity) Ties and other back-ups
Energy Demand	Transformers	Upsizing equipment (higher nameplate capacity) Ties and other back-ups New or accelerated substation additions
Heavy Precipitation	Substations All UG equipment	Substation elevation Water proofing, trenching
Drought	All OH equipment (secondary impact through drought impacts to vegetation)	Enhanced tree trimming & tree removals Higher class poles Reconductoring Undergrounding
Sea Level Rise	Substations All UG equipment	Substation elevation Water proofing, trenching
Storm Surge	All OH equipment	Enhanced tree trimming & tree removals Higher class poles Reconductoring Undergrounding

The Company is currently working on overlaying the results of the climate study shown in the preceding section with the T&D grid maps to understand which individual assets are affected by each climate hazard. The associations tables will be used to optimize mitigations for each climate hazard and asset pair. Since these projects are long-term (probably multi-year), the Company is expecting a need to prioritize projects across time and inform a multi-year resilience plan.

Notwithstanding, the Company is expecting that climate change impacts will create a new normal that will drive change in planning and operations across its entire territory. Thus, the Company is laying the groundwork for the potential re-evaluation of Standards, Operating practices and System Planning as discussed above. As explained below, the Company is expecting a potential new or accelerated need to replace overhead conductors, station and network transformers with higher ampacity and nameplate capacity assets, respectively, as a countermeasure towards increasing ambient temperatures. This need to "upgrade for better" is exacerbated by the secondary effects of climate change (shown in the preceding Section) on the cooling energy demand. System Planning models may require edits to produce cost-efficient solutions with multi-scenario probabilistic inputs such as those returned by the climate science study.

Overhead conductors and station and network transformers are sized and operated based on ambient temperature. Overhead conductor rating is dependent on ambient temperature. The Company's Standards dictate a summer normal, summer emergency, winter normal, and winter emergency ampacity per conductor type and size. The Company expects that both summer and winter ampacities (normal and emergency) would need to be further derated in a warming climate expectation. Table 81 above shows that extreme temperature (as measured through the annual hottest daily maximum temperature) can be a widespread phenomenon by 2050, especially under the 90th percentile SSP5-8.5 scenario, therefore a widespread need for overhead cable ratings update and associated replacements/ upgrades is expected. In urban areas, where cables are mostly underground, Eversource does not expect those conductor ampacities to be in need of derating due to climate-change related ambient temperature change.

The ratings for station transformers and network transformers depend on ambient temperature amongst other factors. In the Company's Standards, the transformer daily peak load standards and ANSI loading limits are expressed as percentages of the transformer's nameplate rating for summer normal, summer emergency, winter normal and winter emergency. These assume a 0C winter ambient and a 25C summer ambient. In a warming climate due to climate change, Eversource expects that those loading factors would need to be derated.

Considerations for transformer operations and sizing during planning shall depend on the loading of the transformer over time. Transformer loss of life is time-coupled, where the hottest spot temperature, which is the critical indicator of the transformer stress and associated loss of life, depends not only on the ambient temperature and the transformer load but also on the pre-existing temperature inside the transformer. In other words, loss of life for a transformer is accelerated when loading is continuously high, in contrast with high loads followed by low load periods that allow the transformer to cool down. This is why the duration of heat waves as well as the maximum daily temperatures alike are both highly influential climate variables for assessing the need to adapt transformer sizing and operating practices in the face of climate change.

The Massachusetts Climate Adaptation and Mitigation Plan, discussed at length in Section 10.1, suggests various secondary impacts possible due to these extreme event manifestations of climate change not considered here as those are low probability and comparatively low criticality. For example, flooding may not impact poles significantly as the base of the pole can be submerged in water for limited time without short- or long-term impacts. However, considering secondary effects of flooding refers to the possibility of the flood waters carrying material potentially damaging to the pole or even pushing objects onto the poles and making dents or increase leaning angles.

Tertiary effects can also be impactful; for example, the efficiency loss of distribution-network connected equipment that further exacerbates demand. A relevant example mentioned above is that of heat pumps and their efficiency being a function of ambient temperatures. Energy demand is already a secondary effect due to higher heating loads because of a warming climate, hence heat pump demand due to efficiency loss is a tertiary effect. Such tertiary impacts are not considered as part of EDC planning or operations unless new manufacturer's standards are published.

11.0 Integrated Gas-Electric Planning

Section Overview

What is Integrated Gas-Electric Planning and why is it needed?

Transitioning from fossil fuel heating to a decarbonized future is a critical component to the decarbonization. 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.

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 gas-electric planning 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. 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 target electrification of heating in ways that avoids 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 decarbonization goals of the Commonwealth. 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 pipeline 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 will be needed in the short term 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

The purpose of integrated planning is to help realize these benefits. Integrated planning will help enable the Commonwealth collectively to

a) Prudently build out the electric system in the right locations at the right time to prepare for conversion of fossil heating to decarbonization 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 like networked geothermal.

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

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

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

2. **Limited-service territory overlap:** To understand the limited degree to which affiliated gas and electric utilities' service territories overlap, it's helpful to look at the share of gas customers served by the affiliated EDC since electricity service is universal. Only 28% of National Grid's gas customers are also National Grid electricity customers. Similarly, approximately 50% of Eversource's gas customers are also Eversource electricity customers. 85% of Unitil's gas pipeline network overlaps with non-Unitil Electric Service territory. Given this level of overlap between National Grid's gas pipeline network with Eversource's electric network and vice-versa, the need for coordinated utility planning on necessary electric investments necessary to ensure gas customers are safely transitioned out of the gas network while ensuring the electric system is prepared to take on the additional electric loading – is critical. More specifically, when a constraint is identified on the gas system, in order to reduce that gas demand with deployment of electrification solutions, another EDC may need to upgrade their electric infrastructure – necessitating a comprehensive data exchange between the LDCs and EDCs regardless of their company affiliation.
3. **Customer adoption:** Electric and gas utilities can transform their capabilities for Integrated Energy Planning (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 by a date certain.
    a. The current approach to demand side electrification incentive programs do not provide for this orderly transition because time-bound, universal adoption of heat pumps, 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 additional incentives be designed in gas-constrained areas or is that a prioritization and an extension of the existing program. If it's the latter, thoughtful consideration needs to be given to achieving the universal adoption of heat pumps 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 electrification hosting capacity is calibrated with electrification deployment. Given that there may be a substantial number of customers currently served by gas, 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 heat pump technology and other energy efficiency technologies and will continue to develop these proposals in the Energy Efficiency Three Year Plans, in concert with the Energy Efficiency

Advisory Council and Equity Working Group members and subject to the approval of the DPU.

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. The preceding chapters 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 electric utilities (i.e., locations where there will be network reinforcement to readily support more electric heat pump 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 would inform the gas planning process and will 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 hosting capacity in each community within the commonwealth. As documented in Chapter 6, resulting from a timely planned execution of the electric investments, each community within the Commonwealth can be ranked based on available electrification hosting capacity. And because of various upgrades implemented in different years within the 10-year period, a community's available electrification hosting capacity may increase over the forecasting period.

11.3. Coordinated Gas-Electric Planning Process

The Commonwealth's utilities have spent time engaging with leading peers across North America and in the UK on integrated energy planning and conducting preliminary internal engineering studies to gather insights on how such planning could work in practice. While some utilities and states or countries are out front, they are all still in a pathfinding mode. No one has figured it all out yet.

Nonetheless, while the ultimate process needs to be fully defined based on pilots, learning, and stakeholder collaboration, several things seem clear about how integrated planning should work:

- 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 DSM 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).
- Where specific gas constraints are identified and electrification hosting capacity is unable to be increased in the required time frame such that electrification of customer loads could resolve the gas constraint, alternative solutions – such as increased adoption of energy efficiency, 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, integrated energy planning will require changes to utility processes, people, and technology. More work is needed to fully detail out what a fully mature capability will require, but some 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 Upgrade Plans by year between EDCs/LDCs with supporting planning analyses, reports, etc.

Joint Utility Planning Working Group

- Establishment of Cross Utility (LDC and EDC) Planning Working Group.
- Working Group meetings ongoing – formal meetings to be established every 2 months with broad stakeholder participation.
- Ultimate objective would be to enable development of coordinated EDC-LDC Long-Range Capital Plan in the long run.

Planning Tools:

- Software tools that translate geographic gas demand with consideration of various weather associated gas demand scenarios into electric system loadings – with embedded assumptions of different electrification technologies.
- Translating those electric loading scenarios through a GIS interface into Distribution Planning models.

People:

- While LDCs and EDCs are staffed to execute on their respective gas and electric plans, assessment of different gas demand scenarios resulting from targeted electrification solutions and executing on coordination process laid out above accounting for drafting annual reports will require incremental FTEs for gas/electric engineering.

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 integrated energy planning 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. Integrated energy planning 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)

As noted earlier, the effectiveness of integrated gas and electric planning will be significantly limited if there is a lack of cross-commodity coordination among peer utilities, including investor-owned utilities and municipalities. Failure to establish appropriate cross-utility collaboration and data sharing frameworks means that the majority of the Commonwealth would not have any integrated gas and electric planning, and thus would not benefit from well-coordinated gas and electric plans.

Thus, establishing a gas and electric coordinated planning working group with representatives from the different Commonwealth electric and gas utilities, MA DOER, AGO, and key affected stakeholders (e.g., environmental, consumer) will be critical.

The working group's objectives should include:

- Develop a shared understanding of the overlapping commodity owners' networks today and their network planning processes.
- Leverage learnings and best practices from other leading utilities in this space (e.g., California, UK, Quebec, Europe).
- Conduct joint gas-electric planning studies to generate learnings and identify near-term opportunities to optimize investments, such as:
  - i. Exchange of gas and electric distribution constraints
  - ii. Conduct and share planning studies to resolve constraints
  - iii. Detail 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 changed needed in processes, technology, people, and data.
- Agree on a prioritized roadmap to develop such capabilities (i.e., what are low hanging fruits 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 energy efficiency program process should align with integrated energy planning.
- Assess future regulatory decisions as well as identify additional policy and regulatory enablers for IEP.
- Explore how best to provide transparency and opportunities for input to various stakeholders.

11.6. Next Steps

Pending GMAC review of the stated objectives, proposed process, and approval of necessary investments in People, Process, and Technologies necessary to execute on the process, the EDCs would proceed with establishment of the Joint Planning Working Groups and report out to GMAC on a quarterly basis.

12.0 Workforce, Economic, and Health Benefits

Section Overview

Eversource is poised to invest in providing a more flexible and resilient electric distribution grid to support and enable a just transition to a cleaner energy future. As grid capacity increases to host more renewable energy generation, the demand for skilled workers in the related industries increases, driving significant direct and indirect employment opportunities. Implemented thoughtfully, these investments will result in new, well-paying, sustainable jobs in the clean energy sector, benefiting communities across Massachusetts. The Company's on-going commitment to new employee training and current employee upskill programs will continue to empower its workforce, enabling employees to adapt to the constantly evolving technology environment. Investments in building and maintaining the distribution grid have both direct and indirect implications economic development in Massachusetts. Direct investment in infrastructure will drive spending on traditional solutions in poles, wires, switches, meters, and substation equipment, including the labor required to build, maintain, and operate the distribution grid. Indirectly, a more flexible and resilient electric system will spur investment in customer-driven clean energy solutions. Every investment in grid modernization will result in positive economic benefits to the Commonwealth. The sustained expenditure and the creation of new good paying jobs in various industries are poised to enrich the region by establishing essential connections with the local economy, creating a multitude of touchpoints that contribute to the overall economic well-being of the area. Delivering health benefits to Massachusetts residents is a major goal of the Company as reflected in the ESMP. Recognizing the affordability concerns among Eversource customers, Eversource supports a series of Energy Efficiency programs. Those programs also help customers to manage energy burdens, providing consumer energy education, supporting a robust energy efficiency workforce, and improving the health and comfort of homes and businesses. The programs also yield considerable non-energy-related benefits, such as improved health outcomes, by directly improving the physical conditions of homes. For instance, improving home insulation increases comfort and reduces thermal stress of the occupants.

12.1. Overview of Key Impact Areas

The Company's ESMP investments in infrastructure and technology will yield significant and tangible benefits to the state's workforce, economy, and the health of its residents. The key to unlocking these benefits is a comprehensive approach to ensuring that investment decisions are made considering the need to support a strong Massachusetts economy where all residents have access to good jobs and live in a pollution-free environment, where the benefits of clean energy are widely dispersed, all while recognizing historical inequities with respect to environmental justice.

As described in Sections 6 and 7, Eversource is poised to invest over $6 billion in the next five years to provide a more flexible and resilient electric distribution grid to support and enable a just transition to a cleaner energy future. As grid capacity increases to host more renewable energy generation, the demand for skilled workers in the related industries increases, driving significant direct and indirect employment opportunities. Implemented thoughtfully, these investments will result in new, well-paying, sustainable jobs in the clean energy sector, benefiting communities across Massachusetts. Those employment opportunities will include manufacturing, construction, engineering, maintenance, installation, grid operations, energy efficiency, consultancy, electric transportation, and research and development.

In the coming years, the Company will expand job creation efforts to meet the needs of the grid of the future. The Company's on-going commitment to new employee training and current employee upskill programs will continue to empower its workforce, enabling employees to adapt to the constantly evolving technology environment. As a result, the direct impact of such investment will upskill its workforce to help serve the current and future needs of customers. Further, growth and investment in these clean energy industries will result in significant indirect job creation in industries such as solar, battery energy storage, offshore wind, and electrification of heating.

Investments in building and maintaining the distribution grid have both direct and indirect implications for local and the overall economic development in Massachusetts. Direct investment in infrastructure will drive spending on traditional solutions in poles, wires, switches, meters, and substation equipment, including the labor required to build, maintain, and operate the distribution grid. Indirectly, a more flexible and resilient electric system will spur investment in customer-driven clean energy solutions. The Company's investments in advanced metering infrastructure, for example, will enable third-party innovation by empowering customers with greater access to usage information and understanding of ways to reduce bill impacts with energy efficiency and demand response.

A key promise of clean energy is to improve health outcomes through decarbonization and reduction of air and water pollution. Recognizing the disproportionate health effect of pollution on environmental justice communities requires a targeted emphasis on reducing environmental burdens in those areas. The Company's investment plan includes innovative approaches to reduce the environmental impact of electric delivery in local communities Further, the Company's plan involves direct input and feedback from affected stakeholders and communities to ensure environmental justice communities receive program benefits, discussed in Section 3. Reducing energy consumption and peak loads lessens the environmental impacts of energy generation. The Company's comprehensive approach to energy efficiency, demand response, and reduction in line losses through VVO, all reduce the region's greenhouse gas emissions.

12.2. Jobs Training and Impacts to Disadvantaged Communities[233]

The transition to a cleaner electricity grid will require a significant increase across various sectors in the Massachusetts workforce. According to the Massachusetts Clean Energy Center, to meet the need of a net zero grid by 2030, the state will need 1,440 additional electricians, 800 solar photovoltaic installers, 600 line-installers and repairers, 550 construction laborers, and 540 general and operation managers.[234]

Employing over 9,000 professionals supporting safe and reliable energy delivery, Eversource has extensive experience hiring, training, and retaining the workforce needed to engineer, design, build, maintain and operate the grid of the future. Given the unprecedented need for further investment in the distribution system, the Company recognizes the need to enhance all aspects of its workforce development activities.

Supporting the comprehensive, analytics-based planning and design described in this ESMP requires employees with advanced skills that will support engineering and design of the distribution grid. In recent years, the Company has made impressive gains in recruitment of talent with greater focus on a data analytics background. Revamping its approach to system planning, for example, over the past five years, the Company has increased the number of engineers by over five-fold. This revamped approach has resulted in creating teams dedicated to DER interconnection, advanced forecasting analytics, and other advanced occupations. Increasingly, engineering and designing the grid of the future will require sophisticated understanding of the principles of system protection and control. To address this need, the Company has initiated targeted recruitment and training initiatives dedicated to this specialized and in-demand skill set, see Section 12.3.

The growth in workforce demand will also affect the Company's field workforce. The Company's craft workers are dedicated to building and maintaining distribution infrastructure on a planned and emergency basis. An example of job profiles and enhanced competencies includes overhead and underground field operations workers and the need for highly specialized skill sets in field and communications engineers responsible for programming and maintaining electronic equipment required for all automated protection and control operations.

---

[233] "Disadvantaged Communities" is understood as "Environmental Justice Communities" as defined in Section 3.
[234] Massachusetts Clean Energy Center, *Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment,* July 2023, p. 30
https://www.masscec.com/sites/default/files/documents/Powering%20the%20Future_A%20Massachusetts%20Clean%20Energy%20Workforce%20Needs%20Assessment_Final.pdf

The increasing complexity of the distribution system will also drive expanded scope for professionals who staff the Company's 24/7 system operation system dedicated to ensuring safe and reliable power delivery. This need will increase with the added emphasis on dispatch and optimization of DER as grid assets. In recent years, the Company has restructured its system operations function to create a new Grid Management organization staffed by engineers supporting operators ensuring technology and resources are available to support optimal decision making. The need for engineering support of the Company's control room operations will grow significantly over time with technology-enabled transition to the integration of DER into grid operations.

Across the Company, the need to augment the workforce, ensuring emphasis on new and emerging skill sets is undeniable. Eversource has taken steps to address this matter by developing a proactive recruiting strategy to attract experienced workers in highly technical and emerging roles. Eversource actively provides opportunities for employees of all backgrounds, across race, gender, ethnicity, culture, age, disability, and veteran status. Eversource takes a holistic approach to talent development and acquisition by leveraging its Diversity and Inclusion Council and Business Resource Groups; academic institutions at the middle, high school, community, and four-year college levels; and external strategic partners and community-based organizations to broaden the reach to as many targeted alliances as possible.

Eversource has a strong track record in clean-energy workforce development programs. In 2004 Eversource initiated the Electric Power Utility Technology program, in partnership with the Utility Workers Union of America Local 369 and Bunker Hill Community College in Boston. The program was designed to build a diverse pipeline of technical talent for critical positions in electric operations. Since the creation of the program, 18 students per year have received classroom education and real-world training in the field with Eversource crews. Additionally, Eversource provides partial tuition funding for students through paid internships and a stipend.

In 2021, Eversource initiated the Clean Energy Pathways, a workforce development initiative. This program seeks to boost the energy efficiency workforce and increase access to opportunities for individuals historically underrepresented in the industry, including women, people of color, LGBTQI+ people and first generation and/or multilingual individuals residing in environmental justice communities. The program's target is to train 120 interns between 2021 and 2024.

On March 15, 2023, the Company applied to the U.S. Department of Energy Grid Resiliency and Innovation Partnership (GRIP) program as part of the Smart Grid Grants funded by the Infrastructure Investment and Jobs Act (IIJA). If successful, the Company plans to create a pipeline for clean energy jobs, in partnership with the Berkshire Community College, MassHire, the Berkshire Workforce Board, and other local agencies. In partnership with labor unions, the program will provide job training and employment opportunities for workers who are affiliated with a union. The application includes a community engagement plan which is designed to lead to the signing of a community benefit agreement.

The Company strives to solidify its position as an industry leader in training tomorrow's grid workforce, drawing from the experience gained through these established programs. The Company's job training efforts are in line with one of its Four Core Equity Strategies, which includes increasing "engagement with underserved and environmental justice communities through greater collaboration." As such, the Company is committed to continue to create and expand job training programs in partnership with local agencies and with environmental justice community to best address the needs of the grid and of the residents. Thereof, Eversource is committed to expanding and creating new programs that will fulfill the needs of the grid of the future in an equitable way.

12.3. Workforce Training (with Action Plans) – Barriers for Building the Workforce Needed to Build and Operate the Grid of the Future

Eversource is proud of the employees who work in the field to serve Eversource customers across New England. The Company's electric and natural gas field workforce consists of talented, committed employees who work on diverse types of equipment in challenging situations delivering reliable and superior customer service. The Eversource Operations Training philosophy is simple: Support and develop a highly skilled, incident-free, and customer-focused team of employees by providing experienced and newly hired workers with an engaging, comprehensive training curriculum that blends classroom instruction with scenario-based learning and allows field workers an opportunity to practice in an environment where risk has no impact.

The Company's Electric Operations Training department develops, supports, and implements training for employees in the Overhead, Underground, Stations, Field Communications and Engineering teams including progression, refresher, and supervisor training. The training team uses a progressive approach to learning by utilizing interactive training opportunities in the classroom, labs, training yards, and field training with an objective to build technical proficiency and critical thinking skills. In all activities, Operations Training aligns best practices for safety, standards, and customer service in curriculum and training.

One of the challenges of workforce training is the need to incorporate new technologies and work methods into training materials as they are developed. The Electric Operations Training department works closely with electric distribution standards engineering to ensure all workers are trained on new equipment and procedures as they are introduced. In total, the Company has trained over 50 employees working out of the Springfield area work center on either field device operation and installation and/or control room operations. As a result, the Company has developed an efficient, well-informed workforce set up to expand the program cost-effectively, including ongoing measurement and verification of program results under different operating conditions.

Eversource also supports employees seeking advanced academic degrees to support their professional duties. For example, the Company has established a partnership with the Worcester Polytechnic Institute (WPI) to offer WPI programs to Eversource employees on site and online. The partnership includes the opportunity for Eversource engineers to receive a master's degree in power systems engineering. This summer, the inaugural Masters in Power Engineering cohort of Masters in Power saw fifteen Eversource employees graduate.

Eversource is committed to continue creating developmental programs for its own workforce with a particular focus on protection and control, digital communications, and relay operations which are the skillsets which will be more in demand with modernization.

12.4. Location Economic Development Impacts

Every investment in grid modernization will result in positive economic benefits to the Commonwealth. In order to highlight these benefits, the Company has used the Bureau of Economic Analysis ("BEA") Regional Input-Output Modeling System II ("RIMS II") approach to estimate the economic impact based on a capital multiplier specific to the region.[235] The BEA is a United States government agency responsible for the creation of official economic statistics, which provide a comprehensive and up-to-date picture of the United States economy to assist businesses, policy makers, and citizens. The economic impact calculation was based on regional economy-wide impacts of the BEA RIMS II approach and is summarized in the following table.

[235] "*RIMS II Input-Output Model User Guide*." Bureau of Economic Analysis, https://www.bea.gov/sites/default/files/methodologies/RIMSII_User_Guide.pdf.

Table 82: Economic and Employment Impacts of ESMP Investments based on RIMS II Methodology

Summary	
Economic Impact of Final Demand	**$M**
Incremental Benefit (2025-2030)	$1,483
Incremental Benefit (2030-2035)	$1,464
Incremental Benefit (2025-2035)	**$2,948**
Employment Impact of Final Demand	**# Jobs**
Incremental Jobs Impact (2025-2030)	11,162
Incremental Jobs Impact (2030-2035)	11,514
Total Incremental Jobs Impact (2025-2035)	**23,176**

The RIMS II methodology relies on the annual expenditure of program capital, accompanied by an associated economic benefit. Based on this comprehensive modeling, the Company anticipates that capital grid investments, as outlined in the Section 7.1, will yield considerable returns for the overall economy and specifically for the Commonwealth economy. Over the span of 2025-2030, these incremental benefits are projected to aggregate to a total of nearly $1,5 billion. The model also highlights that these incremental benefits are poised to reach nearly $3 billion within the extended timeframe of 2025-2035. The state of Massachusetts will receive a significant portion of these benefits over this timeframe.

Further, these investments are expected to foster the creation of jobs within the state, directly and indirectly. The sustained expenditure and the creation of new good paying jobs in various industries are poised to enrich the region by establishing essential connections with the local economy, creating a multitude of touchpoints that contribute to the overall economic well-being of the area.

Additionally, a key objective of this ESMP is the removal of barriers to the growth of Massachusetts' green economy. As a major clean energy infrastructure initiative, delivering new technology and capabilities to over one million customers, the proposed ESMP will have a positive impact on the state's green economy. The investments resulting from the ESMP are expected to result in significant direct and indirect green job creation over a 20-year period. In addition to benefits associated directly with the Company's plan, Eversource expects the creation of numerous other business opportunities across multiple industries.

The RIMS II Type I multipliers estimate job creation by employing economic multipliers that take into account the direct and indirect employment impacts of economic activity. For direct jobs, the model forecasts the positions directly created as a result of a specific project or investment, like those at a newly built substation. For indirect jobs, the model takes into account the positions created in related industries due to the initial investment, such as third-party entities supplying materials or services to the construction of the substation.5 The RIMS II model forecasts that ESMP investments will generate over 11,000 jobs from 2025 to 2030. Additionally, the model anticipates the creation of more than 23,000 jobs during the extended period of 2025 to 2035 as a result of ESMP investments (see Table 79).

The direct and indirect impacts of these calculations reflect a broad perspective of the impact of the direct economic activity and the associated rounds of spending in the economy associated with these investments. It is important to note that these calculated job creation figures include both full-time and part-time positions and are not equivalent to full-time equivalent (FTE) positions.

According to the RIMS II model, the number of jobs created represents the total change in the job counts across all industries for every additional $1 million of output delivered to final demand. These job creation figures are calculated by multiplying the annual investment by the respective industry's employment ratio at the state level, in this case the Electric Power Generation, Transmission, and Distribution category.

12.5. Health Benefits

Delivering health benefits to Massachusetts residents is a major goal of the Company as reflected in the ESMP. Eversource has established an Equity and Environmental Justice team to progress the frameworks and mindset developed by the Eversource Pro-Equity Advisory Team (PEAT), including the Equity Guidelines. These principles support the idea that all people and communities have the right to equal environmental protection and the right to live, work and play in healthy and safe communities. The Eversource Environmental Management System (based on ISO 14001) guides us in the Company's pursuit to protect the environment and that includes minimizing emissions and addressing climate change through the Company's carbon neutrality goal. Given the established links between climate change, greenhouse gas emissions, air quality, and health; the Company is focused on reducing greenhouse gas emissions in the Commonwealth.[6] Further, environmental justice communities have long been experiencing higher rates of asthma in Massachusetts which are linked to air pollution and low indoor air quality.[7] By decreasing emissions in the transportation system (especially in urban areas), reducing emissions from electric generation, and tackling asthma triggers through energy efficiency programs, the implementation of Eversource's ESMP will be a step toward improved air quality within the environmental justice communities of the Commonwealth.

To facilitate success in reaching the Commonwealth's emissions reduction targets, the Company is focusing on the electrification of the transportation sector, which remains the largest contributor to GHG emissions in Massachusetts (see section 5.1.2.6).

Beyond transportation electrification, the ESMP plan provides multiple opportunities to support cost-effective reductions in carbon emissions. For instance, AMI reduces the amount of CO_2 that is emitted through generation due to the reduction in energy use through the target CVR/VVO and Remote Disconnect "Soft-Close" energy reduction benefits, specifically. For every kilowatt-hour reduced, there is a societal benefit for the associated carbon that is avoided which can be quantified. Enhanced VVO (with AMI) is expected to lower overall energy consumption within the service territory, and soft-close related energy will be avoided through the remote disconnect process. Non-quantified benefits include reduced emissions from fewer truck rolls for meter reading and "no-trouble found" responses and the benefit of reduced NO_x and SO_x emitted through generation and truck rolls.

Recognizing the affordability concerns among customers, Eversource supports a series of Energy Efficiency programs. Those programs also help customers to manage energy burdens, providing consumer energy education, supporting a robust energy efficiency workforce, and improving the health and comfort of homes and businesses. The programs also yield considerable non-energy-related benefits, such as improved health outcomes, by directly improving the physical conditions of homes. For instance, improving home insulation increases comfort and reduces thermal stress of the occupants.

When performed comprehensively, weatherization can reduce several asthma triggers such as mold, cockroaches, mice, dust, other particulate matter, and by-product of combustion from gas cooking stoves and portable unvented heaters.[8] Weatherization also increases the safety of occupants through the testing of carbon monoxide (CO) in homes with combustion appliances, the repair and replacement of gas furnaces, and the installation of CO monitors and smoke detectors. Switching to heat-pumps, which can heat and cool homes, is increasingly recognized as a critical tool to avoiding the detrimental effects of thermal stress.

The energy efficiency programs need to meet multiple objectives and outcomes including meeting electric savings targets, natural gas savings targets, demand reduction targets, and greenhouse gas reduction goals. As such, those programs are an essential tool in helping to meet the Commonwealth's climate goals.

In addition, as a stand-alone technology the solar power Eversource produces reduces air pollution by displacing the need for power generation on the grid. To date, the Company has constructed 22 solar generation facilities totaling 70 MW of solar capacity in Massachusetts. Total solar generation from these facilities in 2022 was over 82,000 MWh, equivalent to saving over 20,000 metric tons of carbon dioxide equivalent based on current e-GRID factors for New England.

Further, the Company is constantly investing in new technologies to reduce emissions in the grid. For example, Eversource partnered with manufacturers to develop new types of breakers without SF_6, known to be the most potent greenhouse gas.

Finally, improvements in electric reliability will benefit customers who depend on electricity for their medical devices, such as breathing machines, power wheelchairs and scooters, oxygen, and home dialysis equipment. Additionally, there is ample literature on outages disproportionately impacting environmental justice communities.9 In its IIJA application, see section 12.2, the Company proposed to deploy a microgrid in the environmental justice community of Pittsfield which would be backed by battery storage systems. In this proposal, the community would decide which critical facilities need to be protected by the microgrid in case of an outage. Consequently, improving reliability will be a step in addressing environmental and health inequities.

Eversource is fully committed to helping achieve the Commonwealth's climate goals. Eversource strives to work in an equitable way, with all stakeholders, to create a healthy environment for all. For instance, reducing emissions from electric generation and transportation will have direct and positive impacts on public health. Being fully aware that environmental justice communities have been historically and disproportionately impacted by pollution-related health issues, Eversource will continue to find ways to engage with these communities in a meaningful way. To maintain its leadership in decarbonization, Eversource will continue to innovate and invest in new grid technologies.

13.0 Conclusion

13.1. Next Steps

Eversource is committed to being a catalyst for an equitable clean energy future. This ESMP presents the Company's comprehensive roadmap to enabling the environmental, health, and economic benefits of decarbonization and climate change mitigation for all Massachusetts communities, with a focus on delivering positive outcomes in historically marginalized communities. Eversource has crafted this ESMP with a detailed, realistic, and actionable plan for the next five- and ten-year periods and a longer-term vision for the steps that will be needed to meet decarbonization targets by 2050.

In the period following the submission of this ESMP 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 findings and recommendations.

Eversource is committed to at least two stakeholder workshops in the fall of 2023 as part of the ESMP filing process. The Company believes generally that the public engagement process should be robust and that proactively soliciting feedback is critical. In addition to the initial stakeholder workshops, to further inform Eversource's engagement efforts around proposed projects from Section 6, Eversource is proposing the development of a new Community Engagement Stakeholder Advisory Group ("CESAG"). The goal of the new advisory group is to develop a Community Engagement Framework ("Framework") that can be applied to Section 6 ESMP projects before they are brought before the DPU and the Energy Facilities Siting Board (EFSB). The composition of the CESAG would be agreed upon by members of the GMAC, and recommendations from the fall ESMP workshops. The CESAG is described in Section 3.

As discussed below, Eversource, in collaboration with other EDCs, will propose ESMP metrics and a reporting template for stakeholder review and comment prior to submitting the ESMP to the Department in January. These metrics and reporting template will be designed to support transparency and accommodate mid-term modifications based on GMAC and stakeholder feedback prior to submission of the Company's next ESMP in 2028.

Finally, the Company is working to refine its customer benefit analysis to include a quantitative and qualitative net benefits assessment, including a quantification of the greenhouse gas emissions reductions resulting from the Company's investments included in the ESMP. This net benefits assessment will be included in the Company's filing with the Department in January 2024.

13.2. Process to Support Updates to ESMP Throughout the Five-Year Cycle

The Climate Law, Section 92B (e) requires the EDCs to submit two reports per year to the Department and the Joint Committee on Telecommunications, Utilities, and Energy on the deployment of approved investments in accordance with any performance metrics included in the approved plans.

To ensure all ESMP reports are valuable, actionable, and support transparency with the GMAC, stakeholders, regulators and policy makers, the EDCs support development of a common reporting template. At a minimum, the template would include provisions for the EDCs to report on progress in implementation, stakeholder engagement, and benefit realization. As described in Section 13.3, the EDCs also support adoption of common performance metrics. Results relative to these metrics are to be included in ESMP reports.

The EDCs recommend bi-annual reporting as follows:

- April 1, for the prior year plan period providing a comprehensive report on ESMP progress, including results relative to performance metrics. (Replacing the current Grid Modernization Plan Annual Report)
- October 1, for the six months of the current year, January through June, to provide a higher-level interim review of year-to-date progress.

This process would involve a review of the prior two bi-annual reports and an assessment and recommendation from the Company or joint EDC's regarding elements of the ESMP or specific investments. The EDCs expectation is that this review cycle will help to refine and improve the ESMP and the ability to move forward in supporting the state's clean energy future in a cost effective and efficient manner.

13.3. Reporting and Metrics Requirements with Common EDC Table

The EDCs fully support the creation of metrics to measure progress and performance of the ESMP investments in relation to the ESMP objectives. The EDCs are performance-focused and aspire to provide safe, reliable, and cost-effective service to all customers every single day. Consistent reporting and metric measures for the ESMP will provide transparency into the performance on the approved ESMPs and provide opportunities to adjust for improvements as the plans are implemented.

The EDCs note that they have already committed to metrics in other areas and there are many filed and publicly available metrics across several open or active dockets at the Department. There are several existing frameworks and reporting constructs that should initially be considered and leveraged for any suitable and transferable metrics.

The EDCs have reviewed the metrics that are currently approved or are in process of consideration by the Department and have classified those investment categories considered to be applicable to the ESMP and those that are not applicable to ESMP.

The following investment categories have existing or pending metrics that are directly applicable to the ESMP objectives. Metrics existing or proposed in these areas could be incorporated into the ESMP reporting template with necessary revisions.

- Grid Modernization
- Electric Vehicles
- AMI / Time Varying Rates
- Interconnection Timelines

The following investment categories have existing or pending metrics that are not applicable to the ESMP given that they are either, specific to an EDC, have a separate existing stakeholder process in place, or are not directly applicable to the ESMP objectives.

- Energy Efficiency
- CIP
- Service Quality
- Performance-Based Multi-Year Rate Plan

The EDCs view the existing set of metrics as an optimum starting point to develop the overall comprehensive set of metrics to measure ESMP investments and outcomes in relation to the ESMP objectives. This starting point can be supplemented with additional metrics that track the ESMPs implementation once approved by the Department.

In addition to including existing metrics into the ESMP reporting template as described above, the EDCs are working to develop new, ESMP-specific, metrics designed to ensure full transparency with respect to all ESMP expected outcomes. The EDCs are planning the following process to develop a full metric recommendation for inclusion in each Company's ESMP filing to the Department in January.

- EDCs propose ESMP metrics (new and existing/proposed) by October 1, 2023.
- Conduct collaborative stakeholder sessions to gather feedback on EDC proposed metrics.
- Final recommendation of ESMP metrics, incorporating stakeholder feedback is presented to the Department in January.

The EDCs propose to deliver both infrastructure and performance metrics, which will include both statewide as well as company-specific metrics, tied to each Company's ESMP goals. Infrastructure metrics track the implementation of approved technologies and systems, and performance metrics measure progress towards the ESMP outcomes.

In developing metrics associated with each goal and outcome as this proceeding moves forward, it is imperative that such metrics follow the following principles:

(1) be susceptible to objective and transparent measurement;

(2) have an established baseline against which performance can be measured;

(3) measure "performance" that is within the EDC's control[1]; and

(4) must also consider whether there are conditions precedent for any metrics that need to be factored into their use or measurement. Metrics that lack these foundational elements could result in unintended consequences of penalizing a utility for performance that is not actually substandard, nor a product of the utility's own efforts.

Additional areas of consideration for creating metrics include:

- Legislative compliance – meet the expectations laid out in the Climate Act.
- State Goals and Policy Delivery – focus on achievement of State policy goals.
- Customer Value – creates/demonstrates value for customers, balancing the burden across customer demographics.
- Inter-Metric Consistency – consider performance metrics holistically, avoiding a metrics paradox, where achievement of one metric necessarily means giving up or failing on others.

The EDCs have developed an initial view of both the statewide and company-specific metrics. The purpose of these ESMP metrics is to record and report information, both internally and to the Department, to GMAC and to the TUE. Infrastructure metrics track a Company's deployment and investments in ESMP projects and technologies. Examples of existing infrastructure metrics include, number of AMI meters installed, number of feeder monitors installed, and milestones for approved technologies and projects.

The EDCs will propose additional performance metrics to track the benefits resulting from the Company's ESMP implementation. Examples of performance metrics include those that measure achievement of specific proposed outcomes, such as energy and demand savings resulting from Volt VAR Optimization.

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Council and other stakeholders throughout the ESMP plan period with discussion and updates supported through the bi-annual reporting. The table below summarizes the categories of metrics the EDCs are working to develop.

Table 83: ESMP Metric Categories

Category	Description
Implementation	Delivery of ESMP investments relative to established milestones
Resiliency	Customers benefitting from resiliency investment and improvements in relevant outage statistics
Electrification and DER Hosting Capacity	Amount of Electrification and DER capacity enabled on the distribution system
Use of DER as a Grid Asset	Amount of capacity enabling Grid Services and Flexible Load
Stakeholder Outreach	Specific engagements with stakeholders including those in EJ, disadvantaged or underserved communities

As noted above, the metrics categories above are expected to have specific metrics that are a combination of the existing metrics discussed above and new metrics created through a stakeholder engagement process related to developing the appropriate metrics for the ESMPs.

13.4. Process to Report to DPU and Joint Committee on Telecom, Utilities and Energy

The EDCs expect an ongoing collaboration with the Grid Modernization Advisory Council throughout the ESMP plan period with discussion and updates supported through the bi-annual reporting. In addition to the GMAC, the bi-annual reports will be provided to the Telecommunications, Utilities and Energy (TUE) working group. As described in 13.2, the EDCs believe the proper timeframe for the bi-annual reporting would 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 overall bi-annual reporting efforts.

14.0 Appendix

14.1. Supporting materials

14.1.1. City Electrification Hosting Capacity (kW per Capita)

City	Region	Population	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Acton	MetroWest	24,021	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	1.2
Acushnet	SEMA	10,559	1.5	1.5	1.5	1.5	3.1	3.1	3.0	3.0	3.0	3.0
Agawam	WMA	28,692	0.9	0.9	1.5	1.5	2.7	2.7	2.7	2.7	2.7	2.7
Amherst	WMA	39,263	0.4	0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8
Aquinnah	SEMA	439	6.0	6.0	5.9	5.8	5.8	5.8	5.7	5.7	5.7	5.6
Arlington	MetroWest	46,308	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ashfield	WMA	1,695	2.1	1.9	4.5	4.6	4.6	4.6	10.9	10.9	10.9	10.9
Ashland	MetroWest	18,832	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1
Barnstable	SEMA	48,916	-0.9	-0.9	-0.9	-0.9	-0.9	0.1	0.1	0.1	0.1	0.1
Becket	WMA	1,931	3.7	3.7	3.7	3.8	5.9	5.9	5.9	6.0	6.0	6.0
Bedford	MetroWest	14,383	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Bernardston	WMA	2,102	1.5	1.5	1.5	1.5	8.7	8.7	15.2	15.2	15.2	15.3
Blandford	WMA	1,215	1.1	1.1	1.1	1.2	4.5	4.5	4.5	4.5	4.5	4.5
Boston	MetroBoston	675,647	0.5	0.6	0.5	0.5	0.5	0.6	0.6	0.6	1.0	1.0
Bourne	SEMA	20,452	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Brewster	SEMA	10,318	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
Brookline	MetroBoston	63,191	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Buckland	WMA	1,816	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.8
Burlington	MetroWest	26,377	-0.1	-0.2	0.3	0.3	1.2	0.6	0.6	0.6	0.6	0.6
Cambridge	MetroBoston	118,403	0.6	0.3	0.6	0.4	1.9	1.9	1.9	1.9	1.9	1.7
Canton	MetroWest	24,370	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Carlisle	MetroWest	5,237	1.5	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4
Carver	SEMA	11,645	-0.1	-0.1	-0.1	-0.1	1.7	1.7	1.7	1.7	1.7	1.8
Chatham	SEMA	6,594	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Chelsea	MetroBoston	40,787	0.0	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2
Chesterfield	WMA	1,186	-0.2	-0.5	3.3	3.3	3.3	3.3	12.3	12.3	12.3	12.3
Chilmark	SEMA	1,212	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.0
Colrain	WMA	1,606	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Conway	WMA	1,761	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Cummington	WMA	829	-0.3	-0.7	4.7	4.7	4.7	4.7	17.6	17.6	17.6	17.6
Dalton	WMA	6,330	1.3	0.9	2.2	2.2	6.2	6.2	6.2	6.2	6.2	6.2
Dartmouth	SEMA	33,783	0.5	0.5	0.5	0.6	2.1	2.1	2.1	2.1	2.1	2.1
Dedham	MetroWest	25,364	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Deerfield	WMA	5,090	0.9	0.9	0.9	0.9	0.9	1.0	3.6	3.7	3.7	3.7
Dennis	SEMA	14,674	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dover	MetroWest	5,923	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
Duxbury	SEMA	16,090	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Eastham	SEMA	5,752	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2

City	Region	Population	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Easthampton	WMA	16,211	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Edgartown	SEMA	5,168	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Fairhaven	SEMA	15,924	1.1	1.1	1.1	1.1	2.2	2.2	2.2	2.2	2.2	2.2
Falmouth	SEMA	32,517	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Framingham	MetroWest	72,362	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.1	0.1	0.1
Freetown	SEMA	9,206	1.3	1.3	1.3	1.3	7.9	7.9	16.1	16.1	16.1	16.2
Gill	WMA	1,551	0.8	0.8	0.8	0.8	10.5	10.5	10.5	10.5	10.5	10.5
Granville	WMA	1,538	4.4	4.4	4.4	4.5	25.5	25.6	25.6	25.6	25.6	25.7
Greenfield	WMA	17,768	0.3	0.3	0.3	0.3	0.3	0.3	1.0	1.1	1.1	1.1
Hadley	WMA	5,325	3.0	3.0	3.0	3.0	3.1	3.1	5.6	5.7	5.7	5.7
Harwich	SEMA	13,440	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.7
Hatfield	WMA	3,352	0.6	0.6	0.5	0.6	0.6	0.6	4.6	4.7	4.7	4.7
Hinsdale	WMA	1,919	2.2	1.2	1.2	1.2	14.2	14.3	14.3	14.3	14.3	14.3
Holliston	MetroWest	14,996	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.7	0.7	0.7
Hopkinton	MetroWest	18,758	1.4	1.4	1.4	1.4	1.4	1.5	1.5	2.0	2.0	2.0
Kingston	SEMA	13,708	1.6	1.6	1.6	1.7	3.2	3.2	3.2	3.2	3.2	3.2
Lanesborough	WMA	3,038	4.0	4.0	6.6	6.6	6.7	6.7	6.7	6.7	6.7	6.8
Lee	WMA	5,788	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Leverett	WMA	1,865	1.0	1.0	1.0	1.1	1.1	1.1	8.4	8.4	8.4	8.4
Lexington	MetroWest	34,454	0.3	0.2	0.6	0.6	1.3	0.8	0.8	0.8	0.8	0.8
Leyden	WMA	734	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1	4.1	4.1
Lincoln	MetroWest	7,014	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Longmeadow	WMA	15,853	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Ludlow	WMA	21,002	0.4	0.4	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3
Marion	SEMA	5,347	-1.4	-1.4	-1.2	-1.2	11.7	11.8	11.8	11.8	11.8	11.9
Marshfield	SEMA	25,825	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Mashpee	SEMA	15,060	-1.0	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0
Mattapoisett	SEMA	6,508	-1.4	-1.4	-1.3	-1.3	4.5	4.5	4.5	4.5	4.5	4.5
Maynard	MetroWest	10,746	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	2.6
Medfield	MetroWest	12,799	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Medway	MetroWest	13,115	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9	0.9	0.9
Middlefield	WMA	385	4.6	-1.7	10.1	10.1	85.7	85.8	113.6	113.6	113.7	113.8
Millis	MetroWest	8,460	4.2	4.2	4.3	4.3	4.4	4.5	4.6	5.7	5.8	5.9
Milton	MetroBoston	28,630	0.5	0.5	0.5	0.5	0.5	3.1	3.1	3.1	3.1	3.1
Montague	WMA	8,580	0.4	0.4	0.4	0.4	0.5	0.5	2.1	2.1	2.1	2.1
Montgomery	WMA	819	1.6	1.6	1.7	1.7	6.7	6.7	6.7	6.7	6.7	6.7
Natick	MetroWest	37,006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2
Needham	MetroWest	32,091	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.3	1.2
New Ashford	WMA	250	15.0	15.1	46.7	46.7	46.8	46.9	46.9	47.0	47.0	47.1
New Bedford	SEMA	101,079	1.0	1.0	1.0	1.0	1.2	1.2	1.9	2.0	2.0	2.0
Newton	MetroWest	88,923	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Norfolk	MetroWest	11,662	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Northfield	WMA	2,866	0.4	0.4	0.4	0.4	5.7	5.7	5.7	5.7	5.7	5.7
Oak Bluffs	SEMA	5,341	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Orleans	SEMA	6,307	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1	-0.1	-0.1	-0.2

City	Region	Population	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Otis	WMA	1,634	0.8	0.8	0.9	0.9	3.4	3.4	3.4	3.4	3.4	3.4
Pelham	WMA	1,280	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.2
Peru	WMA	814	0.8	-1.7	-1.7	-1.7	29.0	29.0	29.0	29.1	29.1	29.1
Pittsfield	WMA	43,927	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Plainfield	WMA	633	-0.4	-0.9	6.1	6.1	6.1	6.1	23.1	23.1	23.1	23.1
Plymouth	SEMA	61,217	0.2	0.3	0.2	0.3	0.6	0.6	0.6	0.6	0.6	0.6
Plympton	SEMA	2,930	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Provincetown	SEMA	3,664	2.7	2.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Richmond	WMA	1,407	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.5	3.5	3.5
Rochester	SEMA	5,717	0.3	0.3	0.4	0.4	5.9	5.9	5.9	5.9	5.9	6.0
Sandisfield	WMA	989	1.4	1.4	1.4	1.4	5.6	5.6	5.6	5.6	5.6	5.6
Sandwich	SEMA	20,259	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Savoy	WMA	645	1.1	-2.2	-2.2	-2.1	36.6	36.6	36.7	36.7	36.7	36.7
Sharon	MetroWest	18,575	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Shelburne	WMA	1,884	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
Sherborn	MetroWest	4,401	-0.9	-0.9	-0.9	-0.8	-0.7	-0.6	-0.6	1.5	1.6	1.7
Somerville	MetroBoston	81,045	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.7	1.7
Southampton	WMA	6,224	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1
Southwick	WMA	9,232	0.7	0.7	0.7	0.7	4.3	4.3	4.3	4.3	4.3	4.3
Springfield	WMA	155,929	1.0	1.0	1.0	1.2	1.2	1.7	1.7	1.7	1.7	1.7
Stoneham	MetroWest	23,244	0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Sudbury	MetroWest	18,934	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.1	1.5
Sunderland	WMA	3,663	0.5	0.5	0.5	0.5	0.5	0.5	4.3	4.3	4.3	4.3
Tisbury	SEMA	4,815	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Tolland	WMA	471	2.9	2.9	3.0	3.0	11.7	11.7	11.7	11.7	11.7	11.7
Truro	SEMA	2,454	4.0	4.1	4.0	3.9	3.9	3.9	3.9	3.9	4.0	3.9
Tyringham	WMA	427	13.5	13.6	13.6	13.7	13.9	13.9	14.0	14.1	14.2	14.3
Walpole	MetroWest	26,383	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
Waltham	MetroWest	65,218	0.3	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5
Wareham	SEMA	23,303	1.2	1.2	1.3	1.4	8.5	8.5	8.5	8.6	8.6	8.6
Washington	WMA	494	11.4	7.2	7.4	7.5	66.4	66.5	66.6	66.6	66.7	66.8
Watertown	MetroWest	35,329	1.6	1.6	1.5	1.2	1.2	1.2	1.9	1.9	1.9	1.7
Wayland	MetroWest	13,943	-0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.6	0.6	0.6
Wellfleet	SEMA	3,566	2.8	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
West Springfield	WMA	28,835	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
West Tisbury	SEMA	3,555	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Westhampton	WMA	1,622	0.8	0.8	0.9	0.9	3.4	3.4	3.4	3.4	3.4	3.4
Weston	MetroWest	11,851	-0.2	-0.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
Westwood	MetroWest	16,266	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5
Whately	WMA	1,607	1.2	1.2	1.1	1.2	1.2	1.2	9.7	9.7	9.7	9.7
Winchester	MetroWest	22,970	-0.1	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Windsor	WMA	831	-0.3	-0.7	4.7	4.7	4.7	4.7	17.6	17.6	17.6	17.6
Woburn	MetroWest	40,876	0.2	0.0	0.3	0.3	0.9	0.5	0.5	0.5	0.5	0.5
Worthington	WMA	1,193	-0.2	-0.5	3.2	3.3	3.3	3.3	12.2	12.2	12.2	12.2
Yarmouth	SEMA	25,023	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

14.2. Glossary

Terms are defined for readers in the section and context in which the terms are used.