EVERSOURCE

New Hampshire Distribution Solutions Plan

Ensuring Safe, Reliable, and Resilient Electric Service for All Customers

June 2024

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1.0 Executive Summary

1.1. Objectives of the Distribution Solutions Plan

Eversource is committed to providing safe, reliable, and resilient electric service to New Hampshire customers. This Distribution Solutions Plan (DSP) details the Company's roadmap to advancing this mission over the next five years, addressing challenges such as aging infrastructure and increasing storm activity, while continuing to address areas of expected load growth. The DSP provides an overview of the Company's planned capital investments, as well as transparency into the process used by the Company to balance multiple objectives and design criteria to develop and prioritize solutions to address the urgent needs of the electric distribution system. Solutions identified as priorities are those add the greatest value in support of the following key themes.

Address aging infrastructure to maintain reliability. Much of the infrastructure used today to deliver electric power to customers has been in service for 50 years or more. Implementing high quality inspection and maintenance procedures, the Company has enabled this equipment to work reliably over time. Over time, however, the risk of failure increases. The Company must increase resources dedicated to programs to replace the highest risk equipment as determined by engineering analysis.

Support increasing loads. In many areas of New Hampshire there are pockets of load growth driven by multiple factors. As described in this DSP, the Company has rigorous methodologies to forecast where loads will emerge and model the ability of existing infrastructure to address the growth in demand. In cases where system upgrades are needed, rigorous planning methods are used to ensure projects are designed and implemented in the timeframe required to meet the need at a reasonable cost to all customers.

Maintain safe and reliable service. In recent years, the Company has made investments that have improved the reliability of service to customers. Technologies such as distribution automation and improved standards have reduced the frequency and duration of outage events for customers. Opportunities remain, however, to build on these gains at a measured pace, based on engineering assessment prioritizing the highest value upgrades.

Harden the system for extreme weather. The current distribution system is increasingly vulnerable to disruption resulting from extreme weather. Targeted resiliency programs, such as undergrounding and reconductoring have the potential to avoid long duration events for many customers. The Company conducts extensive analysis of system hardening options to ensure the highest possible resiliency value at the lowest possible cost.

1.2. DSP Overview

1.2.1. Chapter 2: Current state of the Distribution System

In addition to providing background on the Company's electric distribution system generally, the DSP provides insight into the current capacity challenges, reliability experience and distributed energy resource (DER) penetration for each of five operating regions.

1. **Central Region** – *Manchester area and lower Contoocook Valley communities.*
2. **Eastern Region** – *Portsmouth and the Seacoast region*.
3. **Northern Region** – *Lakes, White Mountains, and Great North Woods regions*.
4. **Southern Region** – *Nashua, Derry, and Milford areas.*
5. **Western Region** – *Monadnock and Dartmouth-Lake Sunapee regions.*

1.2.2. Chapter 3: Distribution Planning Process

The key objectives of the bottoms-up integrated transmission and distribution planning process are to (1) build sufficient capacity to meet instantaneous demand; (2) satisfy power quality/voltage requirement within applicable limits; (3) provide adequate availability to meet customer requirements; and (4) deliver power with required frequency. In addition to an overview of the steps of the planning process and a discussion of planning criteria, this chapter details the steps taken to develop, prioritize and implement the highest value solutions to address identified capacity shortfalls. In addition, the chapter discusses the tools processes used to assess the condition of distribution assets, including field monitoring and testing. Also provided are details on the analytics-based risk assessment approach used to prioritize asset replacements such that assets are replaced on a more cost-effective planned and programmatic basis, avoiding customer disruption, and added costs associated with asset failure. Finally, the chapter includes a description of the tools, processes, standards, and criteria used to identify and prioritize opportunities to improve system resiliency.

1.2.3. Chapter 4: Electric Demand Forecast

To ensure that there is always sufficient capacity on the system, the Company plans its infrastructure ten years into the future, thus allowing sufficient time for necessary work to be completed before a certain need is realized. Eversource's advanced forecasting and modeling capabilities allow for granular analysis, understanding load growth and projection of impacts on the local distribution system. This chapter details the process used to generate the five- and ten-year load forecast reflecting expected changes in economic development, large new customer additions or "step loads", energy efficiency, distributed generation, and electrification of transportation and heating. The most recent available forecast across the system shows that step load additions, driven directly by economic development in the region, are responsible for 49 MW of the forecasted load increase from 2024-2033. Load forecast results are provided for each of the five planning regions, reflecting regional differences in load and generation trends.

1.2.4. Chapter 5: Planning Solutions

In accordance with the forecasting, planning and prioritization processes outlined in Chapters 3 and 4, the Company has developed a plan of specific solutions required to address emerging challenges facing the distribution system to support safe, reliable, and resilient electric delivery to customers. As outlined in this chapter, the plan is designed to maximize the value of investments by employing an analytics-based, risk adjusted methodology to select projects for implementation.

The plan identifies specific solutions aimed at addressing capacity constraints for both substation and distribution line equipment. Over the next decade, the capacity and reliability substation projects will add a total of 660 MW of transformer capacity, an increase of 17% over the existing 3.9 GW installed base. Results are provided for each of the five planning regions. The following are selected highlights.

- **Central Region.** No bulk substation capacity projects are identified in the next five years. Current and future capacity projects are planned to support overloaded step and distribution station transformers when financially viable. Eversource has close collaboration with the heavy industrial area of Manchester Airport and Hooksett with a goal to ensure adequate circuit capacity to serve both residential and commercial loads and support electrification growth.
- **Eastern Region.** Three substation capacity projects are identified for implementation in the next five years. These include a planned project to rebuild the Dover substation and two projects currently in the conceptual stages to address capacity needs in Portsmouth at the Cutts Street substation and in Rollinsford at the Salmon Falls substation. At the circuit level, Eversource needs to continue the expansion of its circuits in Portsmouth downtown area, which is in a revitalization process, with new 12 KV load. Other large towns in the Eastern region have historic 4.16 kV systems which are in the process of conversion, such as Dover where it is near completion of a conversion to 12 kV. Other towns in the region have growth where the overloaded steps require the conversion of the 4.16 kV system to 34.5 kV.
- **Northern Region.** No bulk substation capacity projects are identified in the next five years. At the circuit level, the Company has identified as a concern the fact that the Northern region has limited reactive (motor) load support capability as it has long, radial lines, and large motors at ski resorts at the end of these long lines affect the voltage quality and stability of the system.

- **Southern Region.** One bulk substation capacity project is identified at the South Milford substation. This project is currently in the conceptual phase and solution options are provided in this section. The NH Southern region is similar to the Central region as its load has a linear steady 1% to 2% growth with pockets of new commercial and residential load growth as migration from Massachusetts continues along the I93 corridor. Current distribution line capacity projects are due to overloaded step transformers or overloaded distribution substation transformers (4.16 kV or 12.47 kV).
- **Western Region.** No bulk substation capacity projects are identified in the next five years. The Western town areas are pockets of 4.16 kV systems which are feed from overhead step transformers. These transformers are at or near overload condition and the downtown system is near its end of life, when typically, voltage conversion is required to provide additional load serving capability.

Substation Reliability. As with capacity, Chapter 5 identifies reliability needs by region. With respect to substation reliability, Eversource designs its bulk substations to sustain any single contingency event with no load loss. For each region, the section lists the bulk distribution substations that have been identified in New Hampshire as not meeting the Company's current design criteria. The single contingency events that are planned for include loss of a bulk power transformer, loss of a distribution bus section, and bus tie breaker failure.

Substation Asset Condition. Also detailed are substation asset condition project opportunities. Eversource regularly evaluates the condition of its substations with the goals of maintaining the reliability of and minimizing risk to the system, maximizing the life of distribution assets, minimizing costs, and maintaining a safe operating environment. Eversource collects data on the condition of its assets through various asset inspections (including field monitoring and testing). Eversource also considers other factors when evaluating the overall condition of equipment and the need for its replacement. The factors considered include age and estimated useful life, asset physical condition, equipment obsolescence, failure history, design standards, safety, and spare part availability. Program descriptions are provided for the categories of General Modernization, Transformers, Load Tap Changer Automation, Switchgear, and Substation Security.

Circuit Reliability. Chapter 5 includes a description of the areas of opportunity to cost-effectively address circuit reliability. The Eversource team evaluates and develops cost-effective projects and programs to improve circuit reliability on a continual basis. Over the next several years, the improvement in available fault current, line segmentation, and the creation of circuit ties will support the reliability of Eversource's system both in a blue and grey sky days.

Resiliency. Increasing storm frequency and intensity represent a growing risk to the electric distribution grid. A detailed engineering analysis of the increasing probability of major storms and an assessment of the ways in which distribution assets are vulnerable to extreme weather form the foundation of an analytics-based approach to targeting projects that will provide the greatest reduction in "all-in" outage duration for the associated cost (i.e., including the customer outage minutes for large events traditionally excluded from reliability metrics). This analysis results in a proposed program of resiliency upgrades consisting of, undergrounding, arial cable, reconductoring and vegetation management. The prioritized opportunities are provided by category for each planning region.

Volt-VAR Optimization and Grid Modernization. In addition to traditional solutions to challenges facing the distribution system, new technologies create the opportunity for further gains. In this chapter, the Company outlines how the use of new equipment to better manage voltage and reactive power on the distribution system can create economic and environmental benefit. This program, referred to a Volt-VAR optimization (VVO), uses distribution line technology and centralized management through the Company's existing distribution management system (DMS) to flatten and lower the voltage profile, reducing energy consumption and demand traditionally lost in the delivery of power from the source to the customer, providing a positive benefit-to-cost ratio for customers. Another opportunity to invest in a distributed energy resources management system (DERMS) is identified which proposes to interface new software with the DMS to enable system operators to dispatch demand response and distributed generation to provide grid benefits, such as peak load reduction and power quality management. Additional proposals related to advanced system planning tools, interconnection study and hosting capacity map enhancements will enable the Company to make complex, probabilistic-based assessment of current and forecasted load and generation on the system.

1.2.5. Chapter 6: Investment Summary

In Chapter 6, the Company provides a summary of the magnitude and timing of the investments included in the DSP. The investments are presented in the following two categories:

- **Base Capital Program.** The base capital program includes all investments required to meet the Company's obligation to provide safe and reliable service to customers. The base capital program consists of capital investments in (1) peak load and capacity; (2) basic business, including capital repairs; (3) reliability; (4) new customer connections; and (5) CCI poles.
- **Grid Modernization Enhancements.** As described above, the Company has developed proposals for additional programs intended to go beyond the base capital program. The programs include: Volt VAR optimization and grid modernization and Resiliency. These two opportunities would require revenue support incremental to the base capital program.

In addition, as detailed in Section 5.2.4, the Company is currently investigating projects that combine a customer request for new or expanded service with complementary investments to improve reliability and/or address regional load growth. Defined as "**Co-Optimized Solutions**" these projects are designed to cost-efficiently meet multiple objectives. These opportunities are considered incremental to the base capital program.

2.0 Current State of the Distribution System

2.1. State of the Distribution System and Challenges to Address

The current state of the New Hampshire distribution system has been improving with the implementation of distribution automation devices and TripSavers resulting in reliability performance consistent with the top quartile in the IEEE Benchmarking Survey (see Section 2.1.5). However, there are still many challenges that are inherent to the overhead distribution design, with long radial feeders operating at multiple voltages over difficult terrain and traversing through heavily treed areas. Several circuits have limited fault current availability making them difficult to sectionalize, and many distribution assets are nearing the end of useful life. In addition, the system is vulnerable to major events leading to prolonged outages.

The Company's Engineering team has taken a collaborative approach to identifying and evaluating the state of the distribution system and the challenges we face. Eversource monitors distribution equipment asset health, evaluates risk of premature failing and develops data-driven solutions to improve the quality of service for all customers.

2.1.1. 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 2-1 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, which ultimately deliver power to institutions, businesses and homes (primary and secondary customers).[1]

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 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 DER such as solar photovoltaic (PV) feeding into both the transmission and distribution

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

systems.[2] Figure 2-2 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 EPS (Electric Power System). 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.

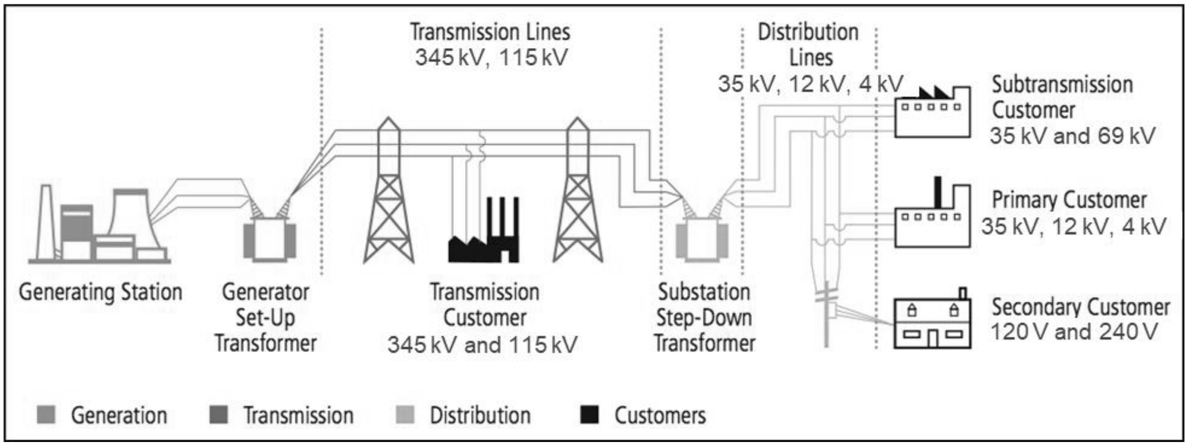


Figure 2-1: Basic Architecture of the Electric Power Grid (Source DOE - Quadrennial Energy Review)

[2] 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.

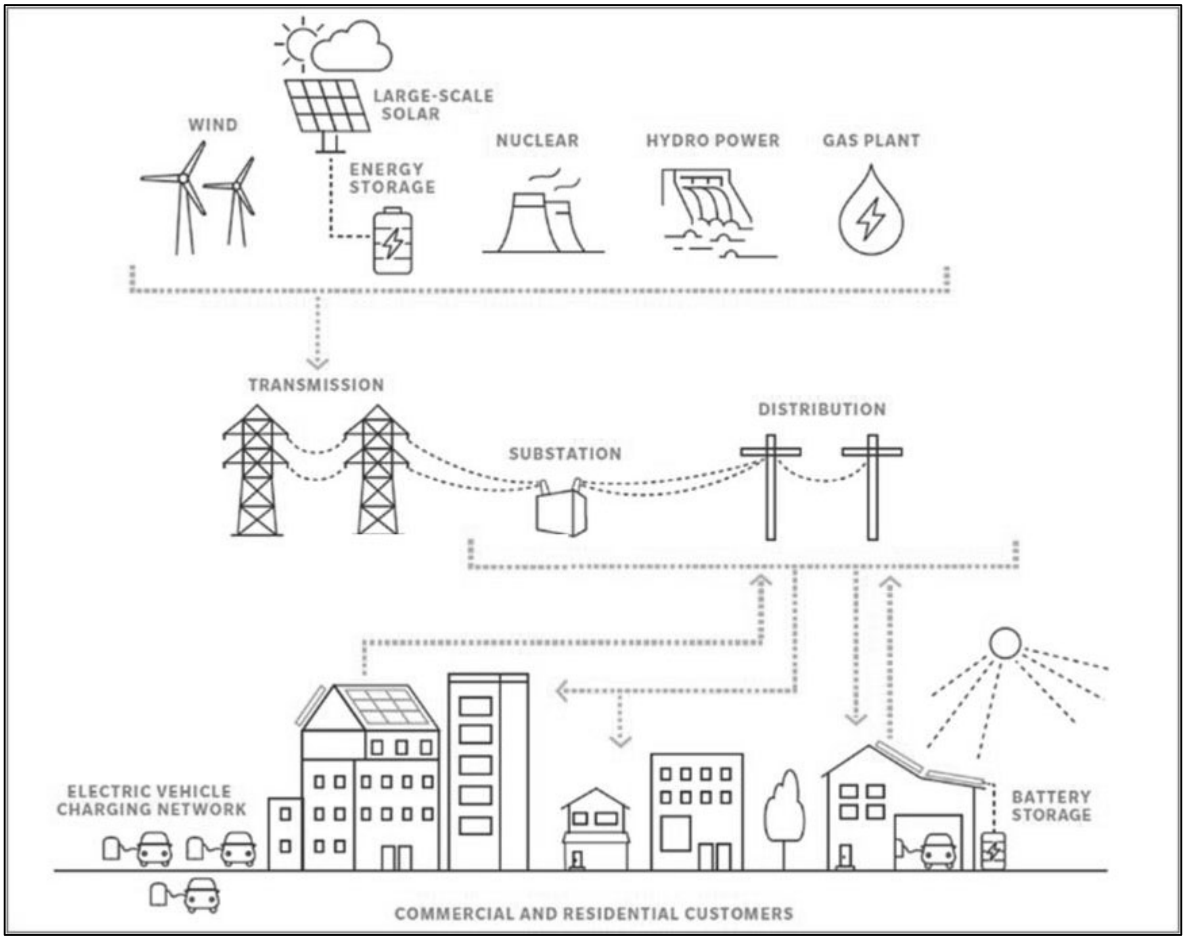


Figure 2-2: Basic Architecture of the Evolving Electric Power Grid

The following are some basic facts on New Hampshire energy production and consumption from the U.S. Energy Information Administration:[3]

- About three-fifths (59%) of New Hampshire households use petroleum products as their primary heating fuel, the second-largest share among the states and almost seven times greater than the national average.
- New Hampshire's residential sector accounted for about one-third of state energy consumption in 2021, even though about 1 in 10 New Hampshire homes are only seasonally or occasionally occupied.
- In 2022, 14% of New Hampshire's electricity generation came from renewable resources, including small-scale solar installations. Most of the state's renewable generation comes from biomass, hydroelectric power, and wind.

[3] Source: Energy Information Administration, *https://www.eia.gov/state/?sid=NH, Last Updated: October 19, 2023.*

- Seabrook, one of only two nuclear power plants in New England and the largest power plant in New Hampshire, provided 58% of New Hampshire's 2022 total in-state electricity net generation.
- New Hampshire has the two, remaining coal-fired power plants in New England - Schiller at Portsmouth and Merrimack at Bow. Coal-fired plants no longer supply baseload power, but they play an important role in providing electricity on high demand days.[4]
- Coal's contribution declined from 25% of New Hampshire's total in-state generation in 2001 to less than 2% in 2022. At the same time, the contribution from natural gas increased from less than 1% in 2001 to 24% in 2022.

The information above highlights that there is a potential future scenario where customers would transition from petroleum fuels for home heating to electric-based heating which will increase demand on the electric system. Eversource's advanced load forecasting processes, discussed in Chapter 4 and Section 5.4.3 will monitor these trends and incorporate them into the demand assessment as they develop. New Hampshire currently has an abundance of in-state generation, even while transitioning away from coal-fired generation, therefore local generation would be critical for meeting this future potential load demand increase. However, the design of the transmission and distribution systems will likely need to evolve significantly to meet the increased demand. The ability of the electric system to move the power regionally and locally reliably, safely, while maintaining operational flexibility will be paramount.

2.1.2. The Company's Power Grid – An Overview

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

- 123 substations (including 50 bulk distribution stations)
- 12,300 circuit miles of overhead lines
- 2,100 circuit miles of underground lines
- 287,900 service transformers

Integral to the provision of safe, reliable service to all customers, load, and DER alike, are bulk distribution substations,[5] also defined as those substations directly supplied from the transmission system. There are 41 bulk substations that supply distribution facilities from transformers which step voltage down from 115 kV to 34.5 kV. There are three distribution substations that operate with 345 kV to 34.5 kV transformers, five that operate with 115 kV to

[4] The retirement of the Merrimack and Schiller Stations in New Hampshire is expected by 2028 and 2025 respectively. (Sierra Club press release March 27, 2024).

[5] The distribution (low) 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 34.5-, 12-, or 4-kV bulk distribution bus-work. This bus is the source for all distribution feeders emanating from that substation.

12.47 kV transformers, and one that operates with a 115 kV to 4.16 kV transformer.

Eversource has an extensive network of 34.5 kV lines in Rights of Way (ROW). These lines provide the sources for 75 distribution (non-bulk) substations that serve customers at 12.47 kV or 4.16 kV. An approximate breakdown of the circuit miles and customer count by voltage is shown in Table 2-1 below.

Table 2-1: NH Circuit Miles and Customer Count by Voltage

Circuit Voltage (KV)	12.47	13.8	3.74	34.5	4.16	8.32
Circuit Miles	6,084	16	79	4,863	2,875	388
Customer Count	213,071	43	43,39	188,799	130,482	10,369

There are numerous independently owned and operated non-utility generating facilities connected to the Eversource system (see Section 2.3 for more information on DER).

The Company's 539,000 electric residential, commercial, and industrial customers constitute approximately 1.8 GW of peak electric demand.

Figure 2-3 below shows the approximate location of the Company's 50 bulk distribution substations (blue circles) across the state. In aggregate, these substations currently have a total nameplate capacity to serve 3.9 GW of customer demand. With the current peak customer electric demand of 1.8 GW in aggregate, the distribution system has an *aggregate* headroom of 2.1 GW. However, this aggregate spare capacity is not the key driver for planning decisions. Because these bulk distribution substations serve local towns and communities, the capacity of each individual bulk distribution substation relative to the customer electric demand in local towns and communities served is more relevant to the available spare capacity and the need to expand the system. Section 5.1 describes projected capacity needs within individual bulk substation service areas and project solutions to reliably serve forecasted demand. Section 8.2 (Appendix) includes tables with the historic loading of the bulk substations in each Planning Region (see Section 2.2 for a description of Planning Regions).

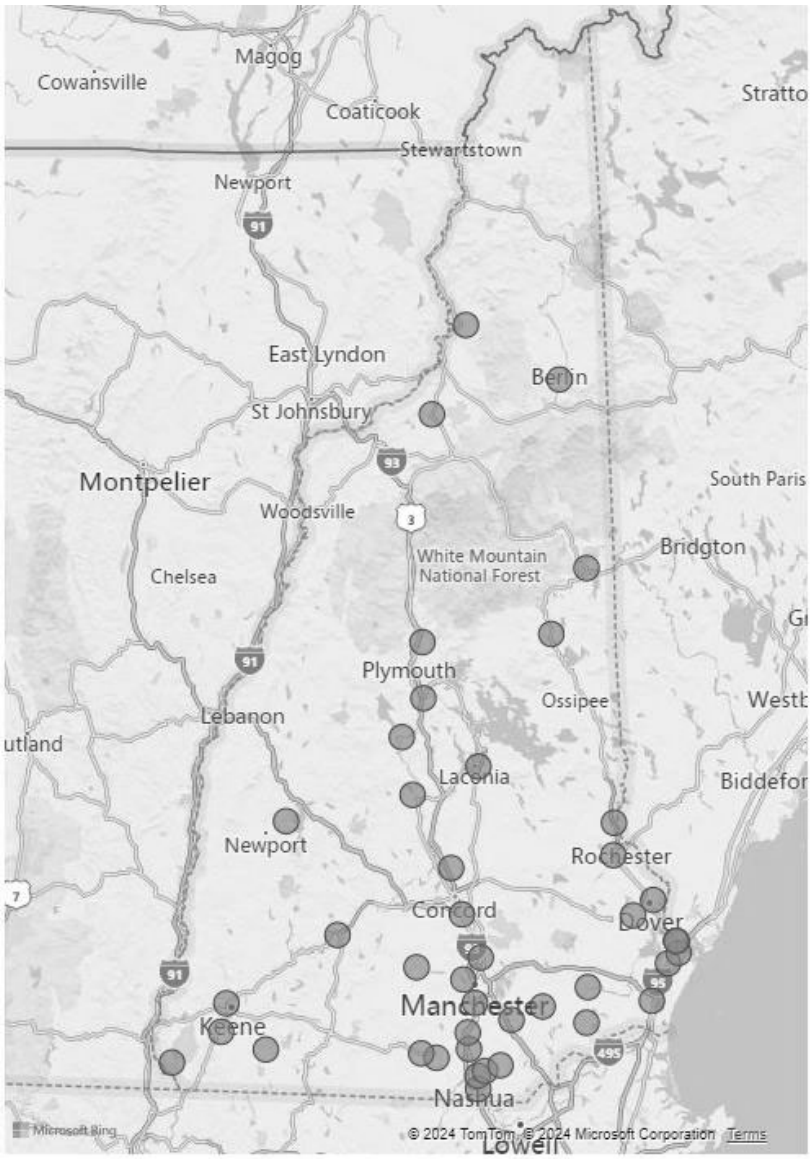
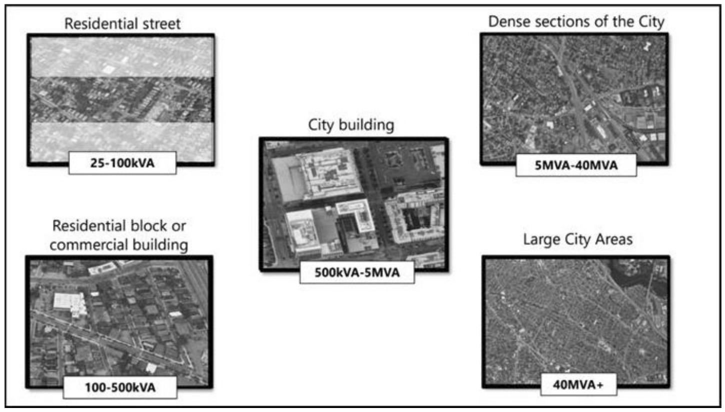


Figure 2-3: Location of Eversource Bulk Distribution Substations in New Hampshire

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 Company tries to strategically place 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 several 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.



The figure to the right 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 increases.[6] Applying these factors to the Company substation map in Figure 2-3, it can be clearly seen that dense load areas such as Merrimack Valley and the Seacoast Regions 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 the Monadnock, Lake Sunapee, Lakes, White Mountains, and Great North Woods Regions of New Hampshire require fewer 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 34.5 kV can serve approximately three times the amount of load as a 12 kV distribution system, with feeders approximately three or four times as long, with fewer bulk distribution substations. Urban areas of the New Hampshire service territory in older established communities such as Manchester, Nashua, Derry, Rochester, Keene, Portsmouth, Laconia, Berlin and the concentrated village centers like Contoocook, Suncook, Sanbornville, etc., operate at 12 kV and 4 kV requiring more substations to serve the same amount of load compared to Dover and communities with newer (1960s+) suburban development that have 34.5 kV 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 demand growth. Nevertheless, some lower (obsolete) voltages, such as 4 kV, are being phased out over time, and

[6] Equipment capacity, such as power transformers, is measured in Volt-Ampere (VA), a thousand Volt-Ampere is 1 KVA and a million Volt-Ampere is 1 MVA. Small residential transformers installed in overhead poles typically range in size from 25 kVA to 100 KVA. Medium size residential pad-mounted transformers installed on the sidewalks or inside customer property are typically in the range of 50 kVA to 500 kVA. Large residential transformers installed below grade or inside customers buildings range in size from 500 KVA to 2,500 kVA or 2.5 MVA.

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

2.1.3. 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 critical elements of the Company's plan for meeting future demand, and providing safe, reliable, resilient service for all New Hampshire customers. Figure 2-4 shows a typical bulk distribution substation with incoming high voltage transmission lines, (115 kV and 345 kV), terminating at high voltage buses, power transformers which step voltage down to distribution levels (4 kV, 12 kV, or 34.5 kV) and outgoing distribution feeders. This differs from a "generating station" where power is "generated" or created.

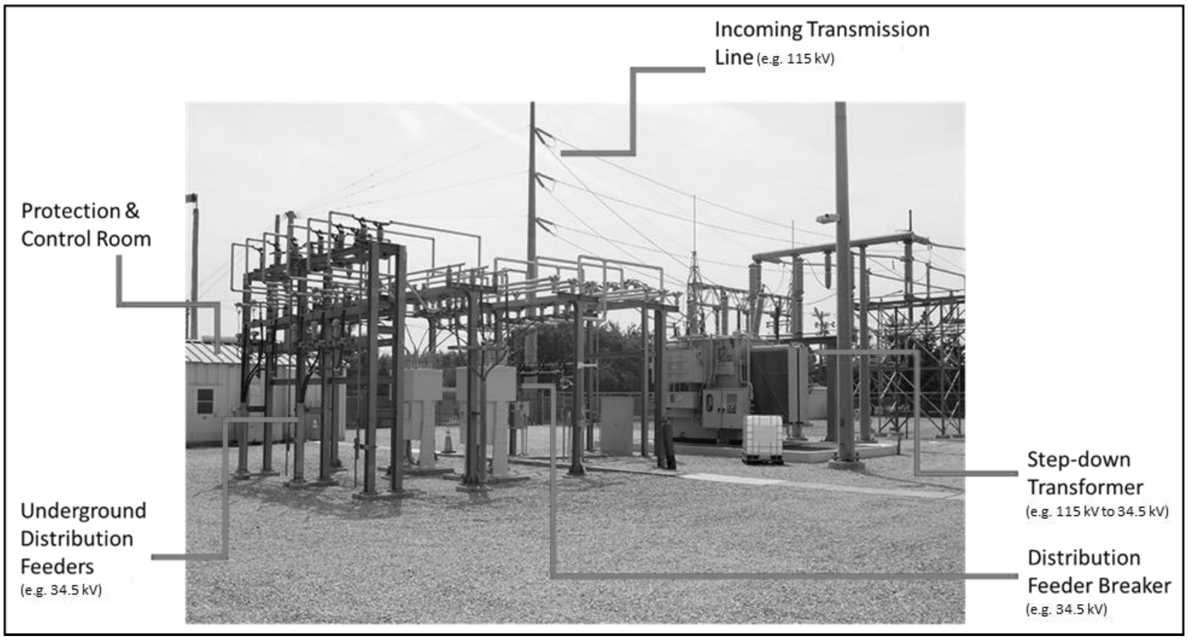


Figure 2-4: Bulk Distribution Substation

The major components of a bulk distribution substation include:

- One or more stepdown power transformers, which reduce or "step down" the incoming 115-kV transmission voltage to primary distribution voltage. Electrically, this is no different than the smaller sized 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 provide 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 enclosure which houses electronic equipment that needs to be protected from the environment and secured.
- Incoming transmission line(s), which supply the bulk substation from the transmission system.
- Outgoing primary distribution feeders, which may be either overhead or underground, supplying 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 sized wires).
- A fenced area surrounding the substation for security, 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 a 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 in some areas, higher expectations for electric reliability, and a desire to increase system resilience, Eversource has standardized on two (2) substation bus topologies (shown in Figure 2-5 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 (2) primary bus sections through two (2) 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.

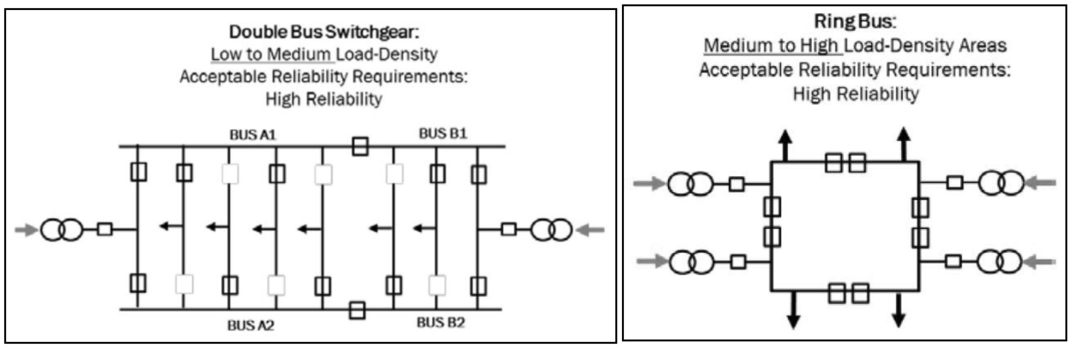


Figure 2-5: Eversource Standard Substation Designs

2.1.4. Planning Challenges

Across the PSNH service territory, there are diverse challenges to the planning mission. Figure 2-6 shows the service territory, highlighting challenges with respect to load and DER in different areas. In the western and northern areas 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 and step load additions are in the population centers of the Merrimack River Valley (Manchester and Nashua) and in the Seacoast region (Portsmouth, Dover, and Rochester). The Merrimack River Valley historically has been the industrial and commercial center of the state, so the electric system is better poised to handle future load growth. However, the seacoast region of the state has been largely rural up until recent decades when population growth has been experienced, introducing a concentration of customers with high peak power demands into an area once largely rural/suburban. Here the electric system sees the challenge of accommodating step load additions.

The geography of the State of New Hampshire with its low population density presents its own unique challenges when developing solutions to address grid needs. New Hampshire residents and visitors enjoy in the natural beauty the state has to offer, from the multiple lakes throughout the state to the majestic White Mountains. Regardless the feature, a benefit that these destinations provide is a secluded atmosphere thanks in part to New Hampshire's low population density. The natural features unfortunately have caused the distribution system in New Hampshire to develop over the decades utilizing an operating voltage higher than typically found in most distribution utilities. Distribution feeders operating at 34.5 kV have the benefit of serving large amounts of load with a single circuit and can travel very long distances to serve customers while maintaining voltage within allowable limits. This works well for building substations in more populated areas, closer to load centers or transmission facilities, and then serving rural areas with long lines out of those substations. With 50 bulk distribution substations serving the customers of Eversource, the members of New Hampshire Electric Cooperative, and parts of Unitil's distribution system, the average area each bulk substation serves is almost 200 square miles. In one location in northern New Hampshire, a customer could possibly be located 50 miles from the bulk substation source. However, while this design may be lower in cost, it is intrinsically less reliable as the many miles of overhead conductor have more exposure to common causes of outages (trees, weather, wildlife) and the higher operating voltage tends to be more susceptible to these types of events. Also, due to the conductor lengths and the sparse design in low-density rural areas, limited contingency support is available from other lines to reduce the duration of customer interruptions.

Compounding the reliability challenge is the fact that low fault current capability on long distribution circuit makes it difficult to sectionalize the lines and ensure proper protection equipment coordination to address line faults.

Eversource uses a large number of step transformers, which are a specialized transformers that convert primary distribution voltages in smaller steps, for example from 34.5 kV (19.9kV) to 12.47 KV (7.2 kV). With the installation of a step transformer, capacity for large load growth is limited. The current procurement lead time for step transformers is over a year and half.

Within the last ten years Eversource had to divest any generation owned in New Hampshire by the Company. Most of this generation was connected to the 34.5 kV system. Though this generation was not relied on in the distribution system planning standards, the divesture did result in decreased operational flexibility 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 (4) 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 (see Section 5.3 for more details). All these challenges exist in some fashion across Eversource's footprint, but in New Hampshire, particularly in localized areas, they are more pronounced.

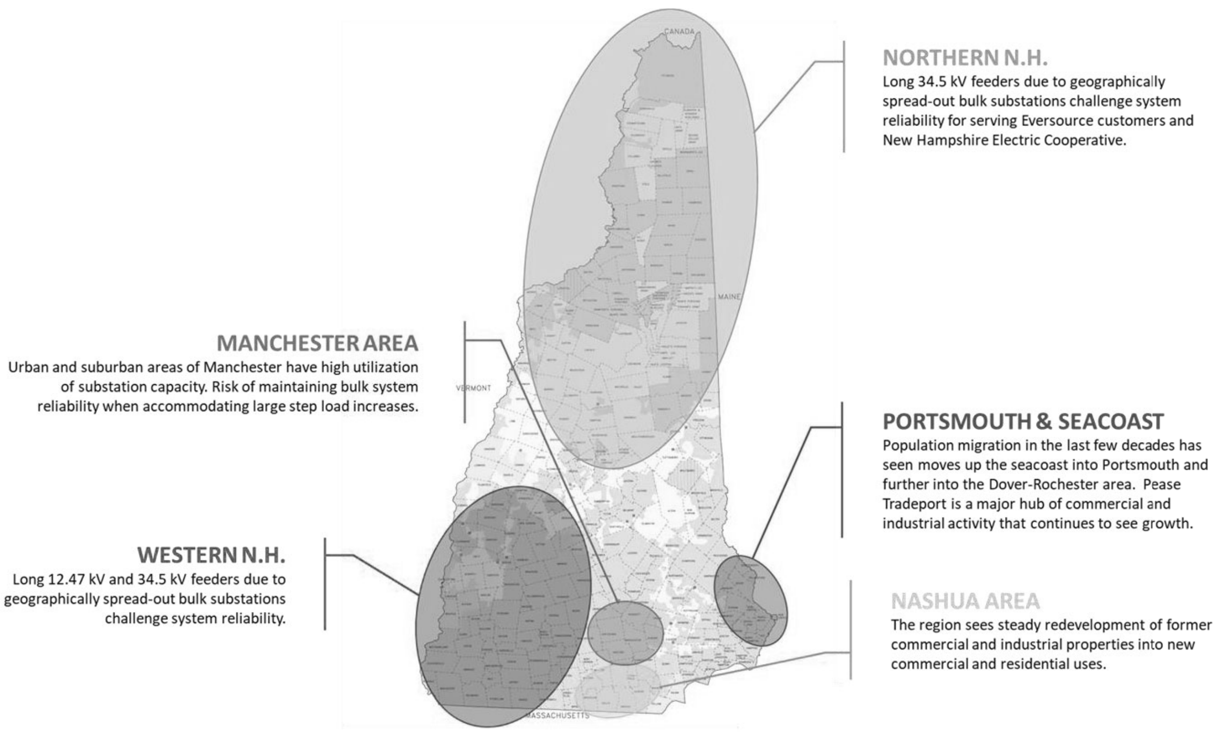


Figure 2-6: Eversource New Hampshire Franchise Service Area (blue communities) and Key Regional Challenges

2.1.5. Reliability and Resilience Measures

In New Hampshire, and across its tri-state footprint, the Company has historically adopted System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) as the standard metrics for quantifying the quality of service experienced by customers during blue-sky days (i.e., excluding major storms). For New Hampshire, the interruptions included in the formulas and results shown below follow the Institute of Electrical and Electronics Engineers (IEEE) rules, which includes interruptions lasting longer than five (5) minutes, referred to as "sustained interruptions". Further exclusions of events not reported include major storms, loss of supply events during blue-sky days, and customer-equipment outages during blue-sky days. Planned outages are included in the formulas and results shown below, per IEEE rules.

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:[7]

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

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, 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, and baselines and comparisons with other utilities can be enabled not just on performance but also in relation to technology deployment and other reliability improvement mechanisms.

As mentioned above, the metrics are called "blue-sky" reliability metrics, where major storm events are typically excluded. This allows 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 of major storm performance (also

[7] Institute of Electrical and Electronics Engineers. " IEEE Guide for Electric Power Distribution Reliability Indices", IEEE Standard 1366-2012, May 2012. https://standards.ieee.org/ieee/1366/7243/

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 interruptions (i.e., interruptions with duration longer than five (5) minutes) at all times, including 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.

Different methodologies to calculate blue-sky SAIDI and SAIFI exist across different states. For example, there may be differences regarding the threshold to exclude an event as a major event/major storm or whether to include planned outages as part of blue-sky metrics. 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). While the IEEE methodology lays out the rules for event inclusion and exclusion as part of blue-sky dataset, the data may not be directly comparable due to differences in collection methods, recording standards, thresholds, system design, etc.

The 2023 results include data from 74 distribution utilities collectively serving 70 million customers. Table 2-2 below shows the results of the survey for all utilities, including the quartiles for SAIDI, SAIFI and CAIDI.

Table 2-2: 2023 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
ALL	MIN	38	22	22	22	0.39	0.20	0.20	0.20	42	39	42	41
	Q1	163	90	86	84	1.12	0.84	0.77	0.68	138	106	109	107
	MEDIAN	250	131	119	111	1.35	1.09	0.93	0.86	183	128	133	134
	Q3	455	191	171	158	1.82	1.47	1.25	1.14	277	149	155	153
	MAX	1711	582	556	518	4.15	2.45	2.42	2.05	603	275	279	289

The Company produces quarterly and annual reports showing reliability performance as well as all-in performance. The quarterly reliability report includes blue sky and all-in SAIDI, SAIFI and CAIDI at the Company level and at the Area Work Center (AWC) level for the previous quarter, as well as some rolling 12-month results. Results on DEMI-3 or more and CELID-6 or more are also included.[8] The annual reliability report presents the same reliability and all-in performance metrics for the past 5 years. This report includes a breakdown per cause of interruption, as well

[8] DEMI-3 (Devices Experiences Multiples Interruptions) represents devices that faulted three times in a given year; CEMI-6 (Customers Experiencing Major Outages) represents the percentage of customers experiencing longest interruption duration of six or more hours, excluding major events.

as information on capital and Operation and Maintenance (O&M) reliability programs and two lists of worst 50 performing circuits, one based on SAIDI, and one based on SAIFI contributions.

2.1.6. Siting and Permitting – An Overview

Eversource is planning the grid to enable customer load growth and DER adoption in a safe, reliable manner. Chapter 5 identifies projects that are critically needed to meet these goals while increasing the reliability, and resiliency of the electrical grid. Key requirements include:

- Provide clear guidance on how to prioritize community engagement at beginning of project development and sustain throughout review process and construction period.
- Develop best practices for creating and sustaining community engagement through formal and informal review processes.

State permitting provide opportunities to engage municipalities, residents and other stakeholders in planning and review of the electric system and related projects. Eversource will work in partnership with community members and other stakeholders to support engagement in any siting review processes, formal and informal opportunities to participate, project needs, site selection, potential impacts and how impacts can be addressed.

2.1.6.1 Siting

The Site Evaluation Committee (SEC) is the agency that has jurisdiction over Eversource transmission lines that meet certain qualifying criteria. In some cases, the transmission infrastructure projects may need to be coordinated with associated distribution projects.

Transmission facilities subject to the SEC's review are:

- New electric transmission lines which are greater than 100 kV *and* are greater than 10 miles *and* are outside an existing transmission corridor.
- New transmission lines greater than or equal to 345 kV.

The SEC is currently composed of nine members: all three commissioners of the Public Utilities Commission and representation of the Department of Environmental Services, the Department of Business and Economic Affairs, the Department of Natural and Cultural Resources, and the Department of Transportation. The remaining two committee members are members of the public appointed by the Governor with background and experience in one or more of the following areas: public deliberative or adjudicated proceedings; business management; environmental protection; natural resource protection; energy facilities design; construction operation or management; community and regional planning; or economic development. Approval is by majority vote of the SEC.

Local zoning agencies have jurisdiction over new or modified substation facilities or for new distribution facilities, as may be applicable.

The Company is aware that there is pending legislation (HB 609-FN) to reform the current SEC process. HB 609 would reduce the number of SEC members from nine to five and eliminate the SEC's ability to use designees or delegate its authority to subcommittees to review siting applications.

2.1.6.2 Permitting

Permitting in the State of New Hampshire is dependent on the type and total land disturbance impacts and impacts to specific jurisdictional resource areas, 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 three (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).

Common New Hampshire state agencies include the Department of Environmental Services (NHDES), Fish and Game Department (NHF&G), Natural Heritage Bureau, Division of Historic Resources (DHR), Department of Transportation (NHDOT), and Division of Natural and Cultural Resources (DNCR). 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, Planning, Zoning and Select Boards, and Public Works.

2.2. Overview of Planning and Operating Regions

As of December 31, 2022, Eversource furnished retail franchise electric service to approximately 535,000 customers in 211 cities and towns across New Hampshire, covering an aggregate area of approximately 5,630 square miles.[9]

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 demand assessments, existing and planned upgrades, and specific challenges faced by the Company are presented by planning and operating region in this section and subsequent sections.

The planning and operating regions that comprise the New Hampshire service area include:

6. **Central Region** – *Manchester area and lower Contoocook Valley communities.* While New Hampshire's largest city is the focus of this region, it does also cover the rural communities out along Interstate 93 and 89. The Everett Turnpike, Interstates 89, 93 and 293, and Manchester-Boston Regional Airport and the concentration of existing businesses and services in Manchester continue to attract steady growth. While Manchester has a robust transmission system and a concentration of bulk distribution substations, the risk to the distribution system is accommodating large step load additions on existing facilities while maintaining bulk system reliability. The rural areas of the region are challenged with system reliability of long 34.5 kV feeders that are 15 to 20 miles in length.[10]
7. **Eastern Region** – *Portsmouth and the Seacoast region*. Of the regions that have seen the most change over the past few decades, it's the seacoast region. A steady migration of the population moving up the seacoast into Portsmouth and north into the Dover-Rochester area has attracted businesses to the growing workforce population. The redevelopment of Pease International Tradeport has become an economic hotspot and has attracted a concentration of many high energy-demand businesses. The electric system originally built to serve the suburban area of Portsmouth and the surrounding rural communities is challenged to support continuing step load additions and maintaining system reliability.
8. **Northern Region** – *Lakes, White Mountains, and Great North Woods regions*. Geographically spread out across about two-thirds of the state, the region includes the seasonal tourism hotspots of Lake Winnipesaukee and the White Mountains. The rural service area has minimal transmission infrastructure with bulk distribution substations spread out serving customers with long 34.5 kV distribution feeders. Northern Region has the most feeders over 10 miles in length, which includes the longest feeder stretching 35

[9] Eversource Energy. "2022 Annual Report", December 31, 2022 https://www.eversource.com/content/docs/default-source/investors/2022-annual-report.pdf.

[10] Feeders, or circuit backbones, in suburban areas are typically at most 10 miles long. City or urban feeders are less than 5 miles in length. Rural feeders stretch anywhere from 10 to 35 miles long in New Hampshire. This does not take into account the length of the circuit taps that radiate out from the backbone to the customer service locations, which can be just as long, if not longer, than the entire circuit backbone.

miles long. System reliability and accommodating large volumes of DER interconnections are challenges in this region.

9. **Southern Region** – *Nashua, Derry, and Milford areas.* Southern Region is the smallest region geographically but serves the most load of the five regions in New Hampshire. The region includes the suburban border communities Nashua, Milford, and Derry and each's respective surrounding towns. Transportation access with the Everett Turnpike and Interstate 93 and Nashua being the state's second largest city provides a recipe for attracting steady growth and redevelopment of residential, commercial, and industrial properties. Due to the attraction to this area, accommodating step load additions on the bulk distribution system is a risk.
10. **Western Region** – *Monadnock and Dartmouth-Lake Sunapee regions.* Covering the southwest and western parts of the state, the region is rural with many campgrounds and seasonal lakeside homes. Localized growth is seen with the redevelopment of the lakeside properties to year-round homes. Like Northern Region, minimal transmission infrastructure serves geographically spread-out bulk distribution substations and long 12.47 kV or 34.5 kV feeders (ranging from 10 to 24 miles in length) which challenges system reliability. Since available land makes this region prime for DER interconnections, another challenge is ensuring system capacity for a system built for light load density.

The regions are defined this way based on several factors including historical precedence as Eversource predecessor Company service areas; service area geography; and historical and forecasted load growth characteristics. High-level data for each region including peak load, connected and pending DER, number of customers, number of substations, and DER saturation level are summarized in the Table 2-3 below. Figure 2-7 shows a map of the regions.

Table 2-3: Eversource Planning Region Summary Data

Region	Central	Eastern	Northern	Southern	Western
Customer Accounts*	119,100	111,100	101,100	136,400	74,800
Bulk Substations	8	11	12	12	7
DER Penetration	Low	Low	High	Low	High
Online DER (MW)	78	67	177	47	87
In-Queue DER (MW)	41	98	180	106	165
Peak Load 2023 (MW)	474	461	276	495	181
Customers per Substation	14,888	10,100	8,425	11,367	10,686
On-Line DER as % of Peak Load	16%	15%	64%	9%	48%
Online + Queued DER as % of Peak Load	25%	36%	129%	31%	139%

** Note: Customer Accounts are Eversource's retail customers only. This does not include customers of Unitil nor members of New Hampshire Electric Cooperative supplied by Eversource's bulk substation facilities.*

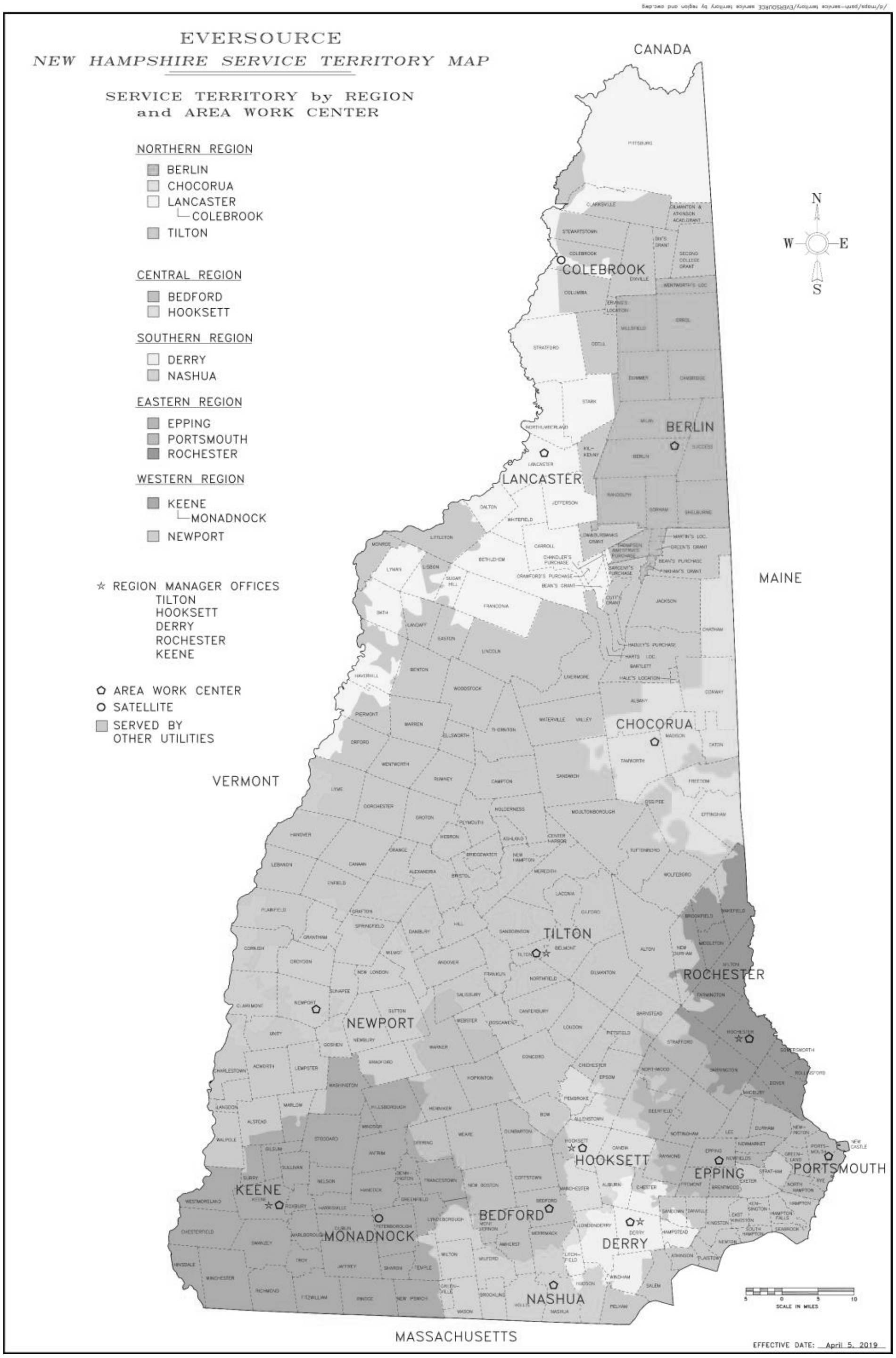


Figure 2-7: Map of New Hampshire showing planning regions and area work centers.

2.3. Capacity and Reliability Overview by Region

2.3.1. Central Region

The Eversource NH Central Region consists of the city of Manchester and all or part of 30 towns (Allenstown, Amherst, Auburn, Bedford, Bow, Candia, Deerfield, Deering, Dunbarton, Epsom, Francestown, Goffstown, Henniker, Hillsborough, Hooksett, Hopkinton, Litchfield, Londonderry, Lyndeborough, Merrimack, Milford, Mont Vernon, New Boston, Pembroke, Raymond, Salisbury, Sutton, Warner, Weare, and Webster) in southern New Hampshire served out of nine (9) bulk substations with a peak electric demand of approximately 474 MW in 2023. This region has a total online DER from all sources of approximately 78 MW. The service area encompasses a population of approximately 247,000 residents and 119,100 customer accounts. Figure 2-8 below is a portion of Figure 2-7 that shows the bulk substation locations (white squares) in the NH Central region.

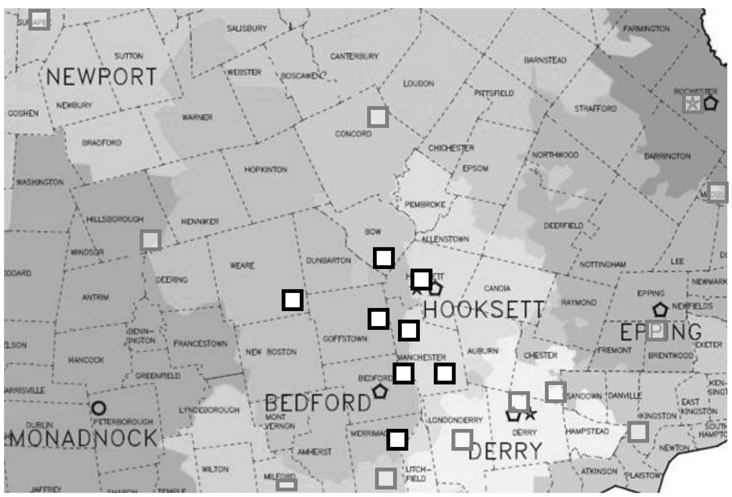


Figure 2-8: NH Central Region (blue areas) Showing Area Work Centers (pentagons) and Bulk Substations (squares)

While not part of the Eversource service territory, most of the Concord area served by Unitil is supplied through Eversource's bulk substation facilities and distribution system.

This region consists of low- to medium-load density areas, including: a concentration of medium-to-small commercial and manufacturing in and around Manchester; Manchester-Boston Regional Airport; medical facilities such as Catholic Medical Center, Eliot Hospital, VA Medical Center; city, state and federal government offices and services; academic institutions such as Magdalen College of the Liberal Arts, Manchester Community College, New England College, Saint Anselm College, and Southern New Hampshire University; sports venues such as SNHU Arena and Delta Dental Stadium; trade show and conference venue such as the Center of New Hampshire Expo; critical service loads such as the Manchester Water Works and Manchester water treatment facility; and regional print media, television and radio broadcasting facilities.

2.3.1.1 DER Adoption (Battery Storage and PV Solar)

As shown below in Figure 2-9, the total online solar PV currently in the NH Central region is 32.6 MW with another 0.9 MW of PV coupled with battery storage. The total amount of hydro-generation is 38.7 MW, constituting about half the installed capacity. There is 5.5 MW of natural gas-based reciprocating engine generation and the total online DER from all sources is approximately 78 MW which represents a relatively low level of DER deployment (16%) compared to area native load.[11]

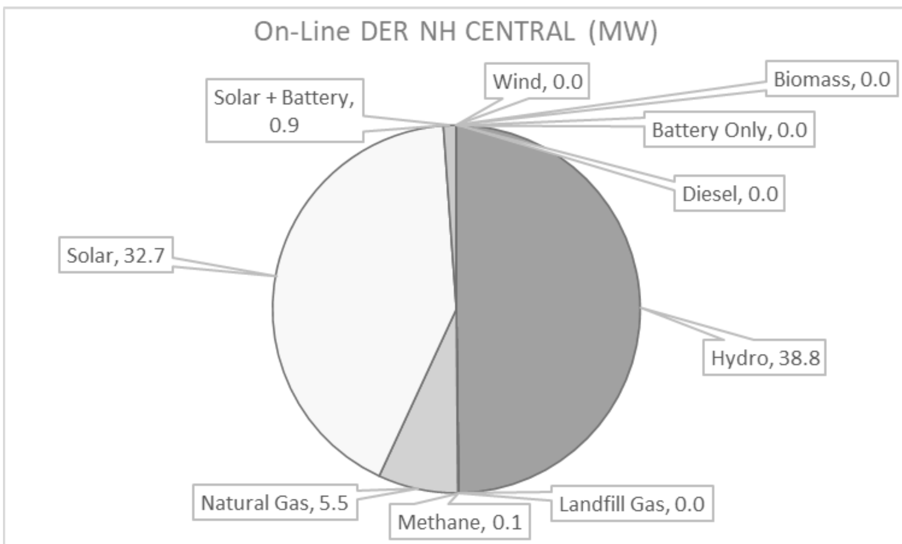


Figure 2-9: NH Central Online DER by Fuel Type

Figure 2-10 below shows the in-queue DER in the NH Central 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: 36.6 MW of solar, 2.4 MW of fuel-oil based generation, 2 MW of diesel, 300 kW of solar plus storage and about 100 kW of standalone storage. The total DER in-queue or in the study process is 41.4 MW.

[11] Per latest tracking system extraction.

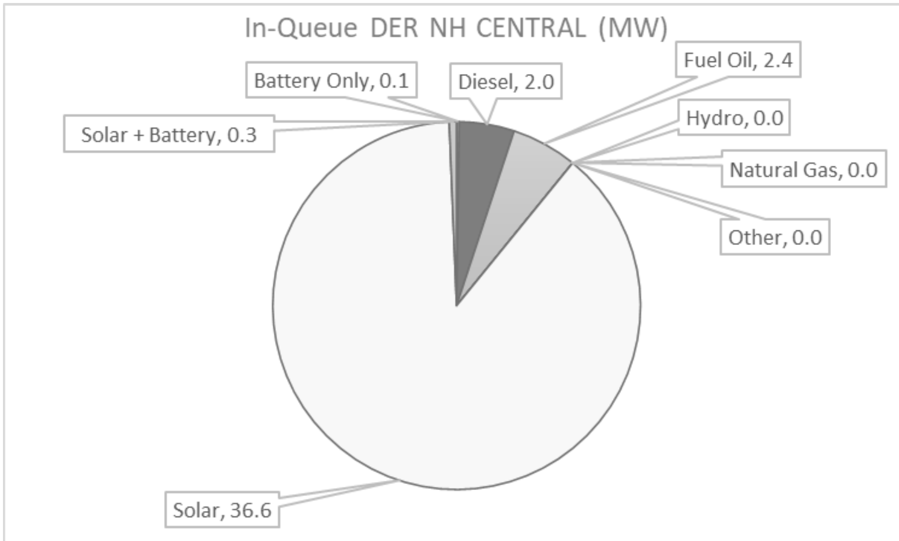


Figure 2-10: NH Central Queued DER by Fuel Type

2.3.1.2 Substation Capacity Overview

Over the past decade, non-weather normalized bulk substation peak loads in NH Central Region have ranged between 460 MW and 520 MW as shown in Figure 2-11. Overall nameplate capacity of the substations in this region is presently at 765 MVA. While utilization is at 68% of nameplate capacity, the available headroom ensures system capacity during contingent events when a piece of equipment is removed from service for planned or unplanned work. The decrease in capacity seen in 2020 is due to the retirement of a transformer with poor asset health.

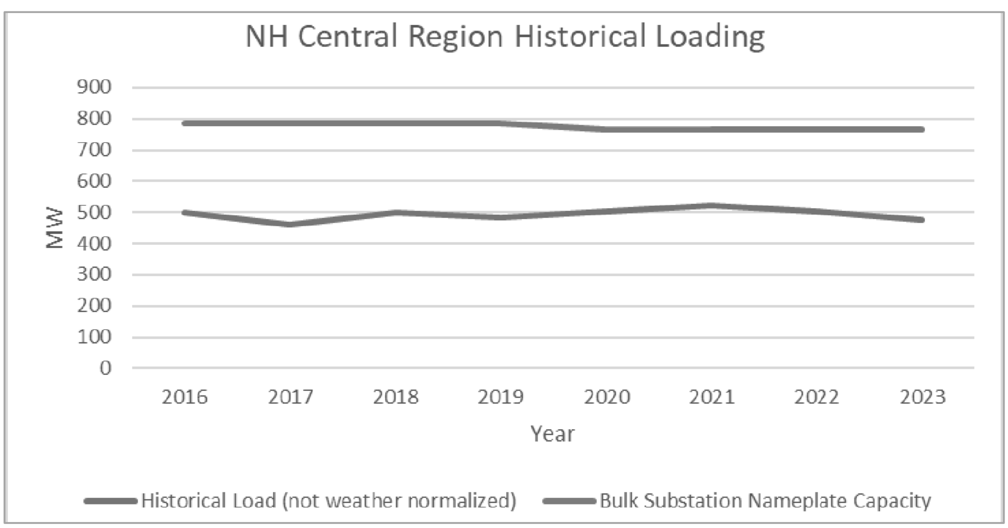


Figure 2-11: NH Central Region Historical Peak Loading and Bulk Substation Nameplate Capacity

For substation-level peak loading detail and capacity utilization, see Appendix, Section 8.2.1.

2.3.1.3 Circuit Reliability and Resilience Overview

Section 2.1.5 above includes definitions of commonly used reliability metrics and definitions of blue-sky and All-In performance measures.

Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI per region are shown below as calculated using IEEE rules. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region would align with (although PSNH reliability performance is reported as a single company-level performance metric to IEEE). In recent years, performance in NH Central is consistent with top quartile performance for SAIDI and SAIFI.

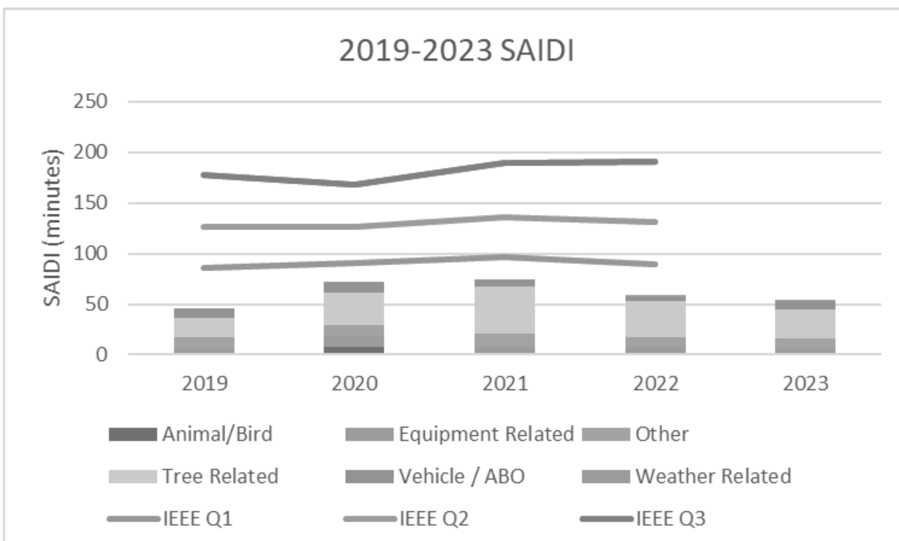


Figure 2-12: 2019-2023 NH Central Blue-sky SAIDI and IEEE Quartiles' Threshold Values

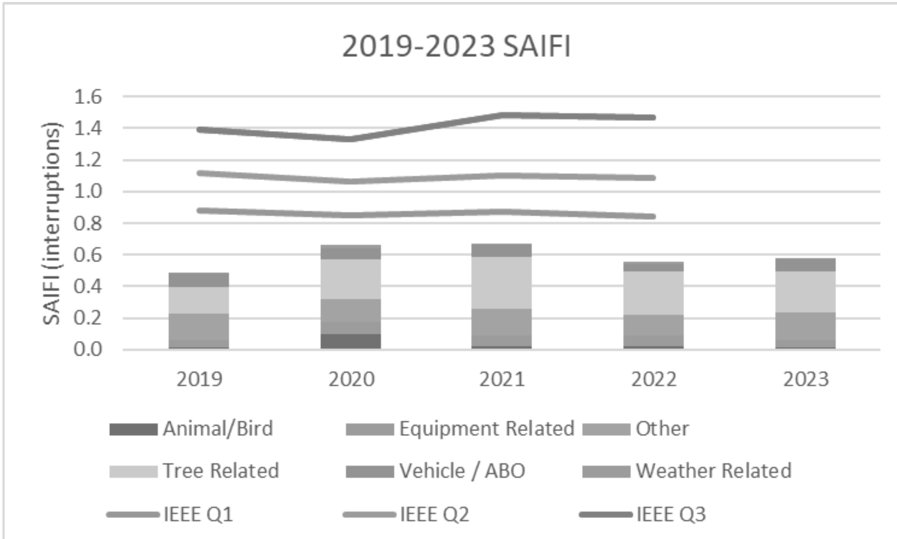


Figure 2-13: 2019-2023 NH Central Blue-sky SAIFI and IEEE Quartiles' Threshold Values

All-In Performance

All-in SAIDI and SAIFI for NH Central from 2019-2023 are shown below. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region aligned with (although PSNH Electric reliability performance is reported as a single company performance metric to IEEE). In recent years, all-in performance in NH Central is consistent with top quartile performance for SAIDI and SAIFI.

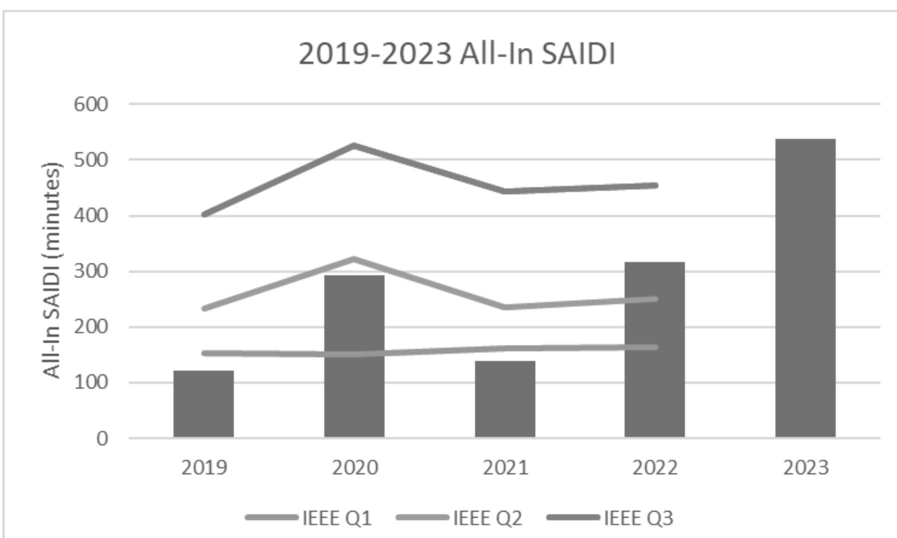


Figure 2-14: 2019-2023 NH Central All-in SAIDI, and IEEE Quartiles' Threshold Values

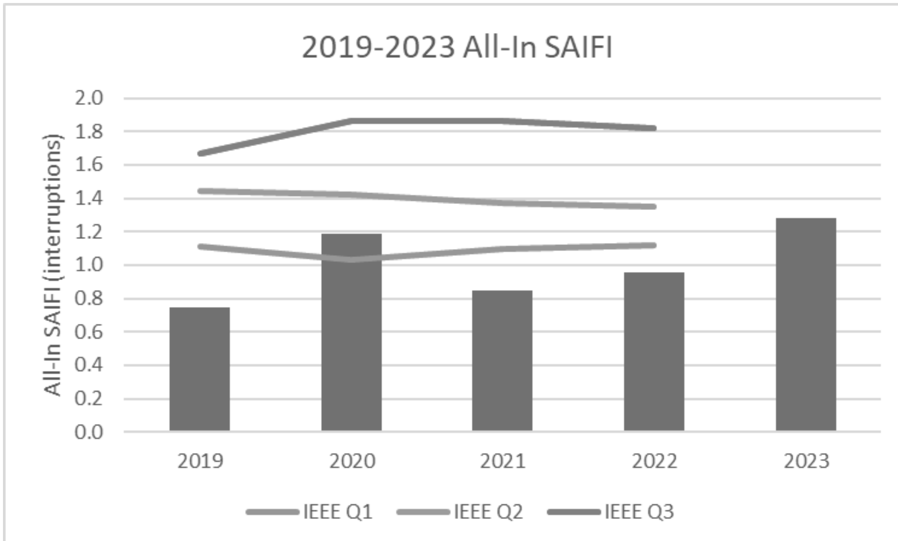


Figure 2-15: 2019-2023 NH Central All-in SAIFI and IEEE Quartiles' Threshold Values

2.3.2. Eastern Region

The Eversource NH Eastern Region consists of four (4) cities (Dover, Portsmouth, Rochester, and Somersworth) and all or part of 32 towns (Alton, Barnstead, Barrington, Brentwood, Brookfield, Chester, Deerfield, Durham, Epping, Epsom, Farmington, Fremont, Greenland, Lee, Madbury, Middleton, Milton, New Castle, New Durham, Newfields, Newington, Newmarket, North Hampton, Northwood, Nottingham, Pittsfield, Raymond, Rollinsford, Rye, Strafford, Stratham, and Wakefield) in eastern New Hampshire served out of 11 bulk substations with a peak electric demand of approximately 461 MW in 2023. This region has a total online DER from all sources of approximately 67 MW. The service area encompasses a population of approximately 228,000 residents and 111,100 customer accounts. Figure 2-16 below is a portion of Figure 2-7 that shows the bulk substation locations (white squares) in the NH Eastern region.

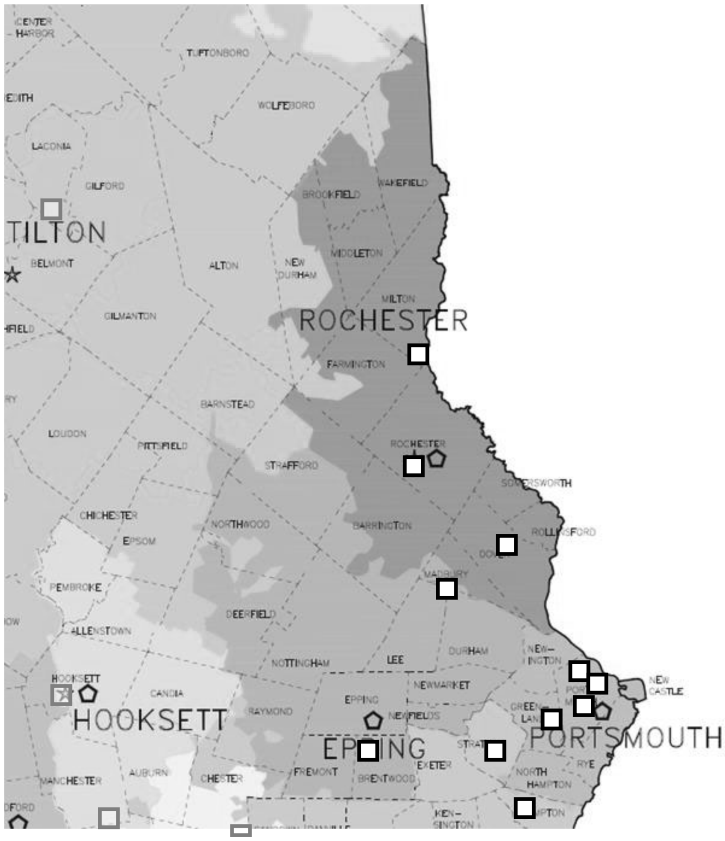


Figure 2-16: NH Eastern Region (purple areas) Showing Area Work Centers (polygons) and Bulk Substations (squares)

While not part of the Eversource service territory, much of the Exeter-Hampton area served by Unitil is supplied through Eversource's bulk substation facilities. Eversource also supplies New Hampshire Electric Cooperative service areas in Alton, Brentwood, Deerfield, Lee, and Raymond from the 34.5 kV distribution system.

This region consists of low- to medium-load density areas including: a concentration of medium-to-small commercial and manufacturing in and around Portsmouth and the Pease International Tradeport; medical facilities such as Frisbie Memorial Hospital, Portsmouth Regional Hospital, and Wentworth-Douglass Hospital; city, state and federal government offices and services; academic institutions such as Great Bay Community College and University of New Hampshire; and critical service loads such as local municipal water and wastewater facilities. Step load growth in the Eastern Region is high with new development in the downtown Portsmouth area and new and expanding businesses at the Pease International Tradeport.

2.3.2.1 DER Adoption (Battery Storage and PV Solar)

The Eversource NH Eastern area has the relatively low DER penetration (15% of the region's peak load) and has the second lowest share of DER applications in the queue.

As shown below in Figure 2-17 there is 33.9 MW of installed solar and less than 1 MW of solar coupled with battery storage. The next highest amount of DER online is 25.5 MW of landfill gas generation and 5.4 MW of hydro. The total online DER from all sources is 67.1 MW.[12]

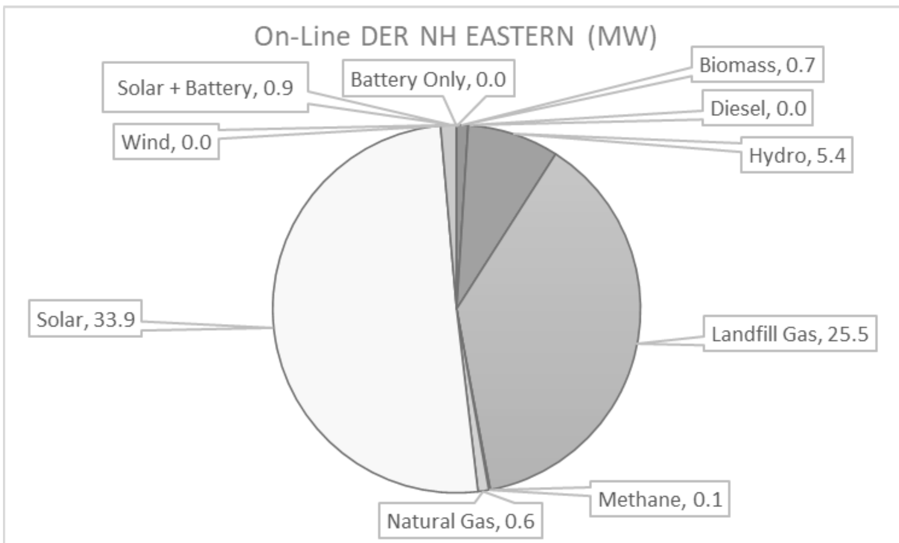


Figure 2-17: NH Eastern Online DER by Fuel Type

Figure 2-18 below shows the in-queue DER in the NH Eastern 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: 85.7 MW of solar, 10.3 MW of diesel, 1.2 MW of natural gas and 600 kW of solar coupled with storage. The total DER in-queue or in the study process is 98.2 MW.

[12] Per latest tracking system extraction.

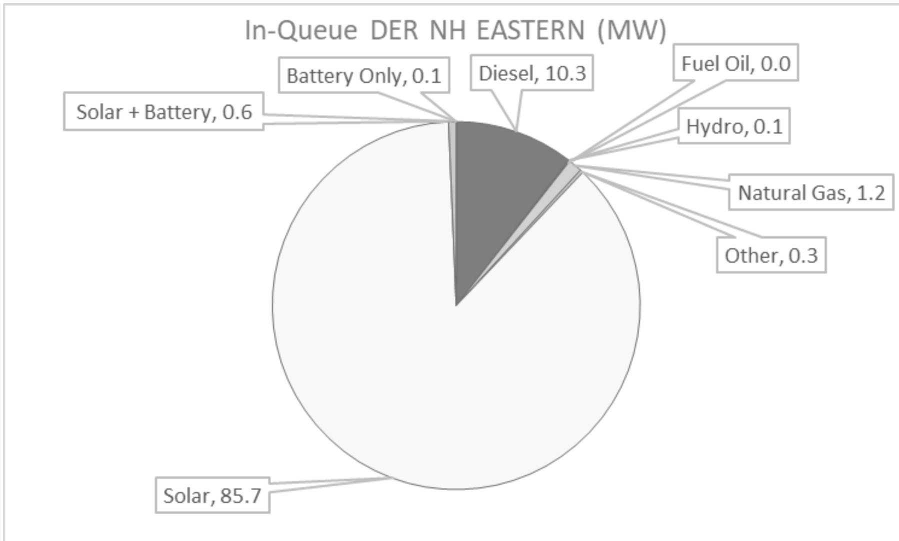


Figure 2-18: NH Eastern Queued DER by Fuel Type

2.3.2.2 Substation Capacity Overview

Over the past decade, non-weather normalized bulk substation peak loads in NH Eastern Region have ranged between 460 MW and 890 MW as shown in Figure 2-19.. Overall nameplate capacity of the substations in this region is presently at 892 MVA. While utilization is at 59% of nameplate capacity, the available headroom ensures system capacity during contingent events when a piece of equipment is removed from service for planned or unplanned work.

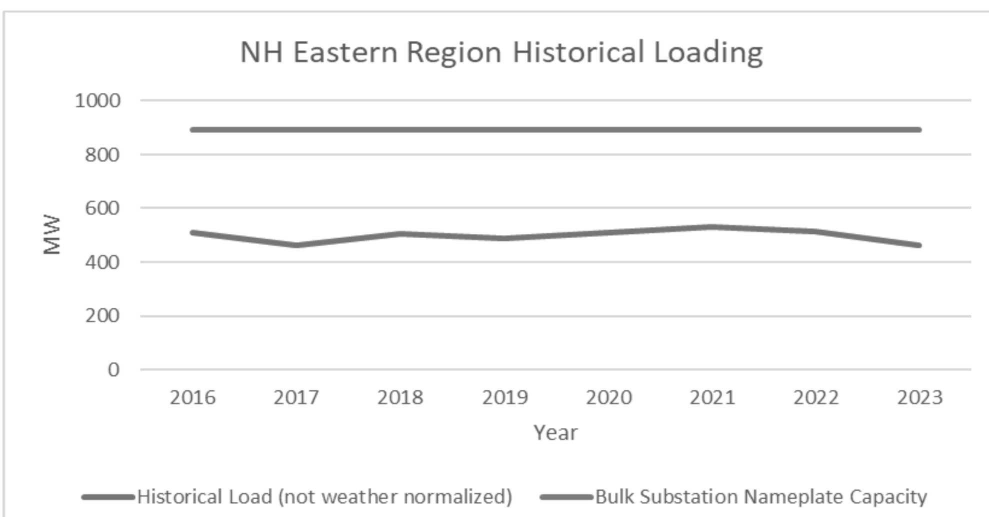


Figure 2-19: NH Eastern Region Historical Peak Loading and Bulk Substation Nameplate Capacity

For substation-level peak loading detail and capacity utilization, see Appendix, Section 8.2.2.

2.3.2.3 Circuit Reliability and Resilience Overview

Section 2.1.5 above includes definitions of commonly used reliability metrics and definitions of blue-sky and All-In performance measures.

Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI per region are shown below as calculated using IEEE rules. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region would align with (although PSNH reliability performance is reported as a single company-level performance metric to IEEE). In recent years, performance in NH Eastern is consistent with top quartile performance for SAIDI and SAIFI.

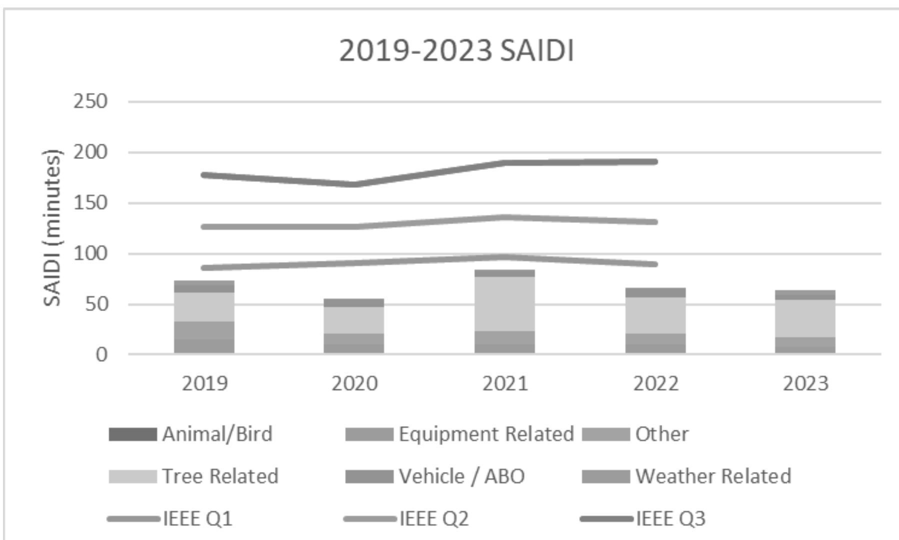


Figure 2-20: 2019-2023 NH Eastern Blue-sky SAIDI and IEEE Quartiles' Threshold Values

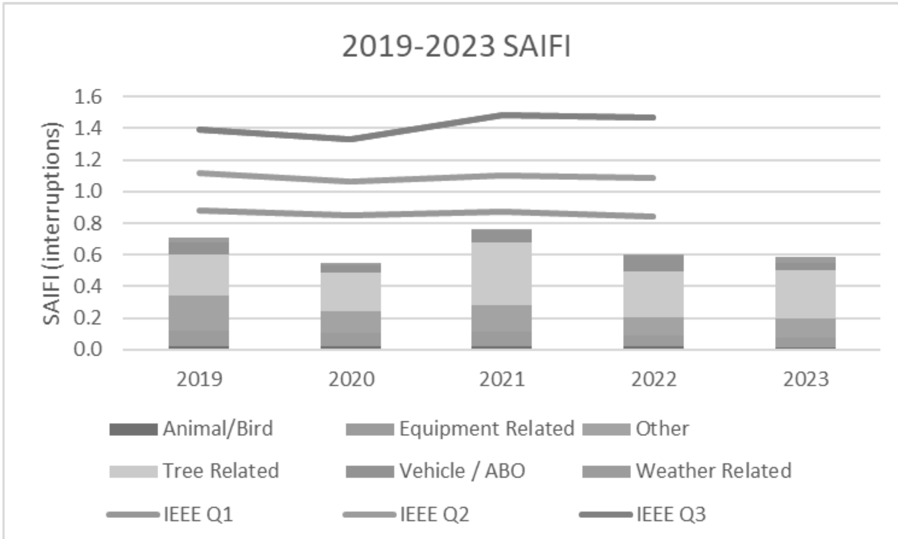


Figure 2-21: 2019-2023 NH Eastern Blue-sky SAIFI and IEEE Quartiles' Threshold Values

All-In Performance

All-in SAIDI and SAIFI for NH Eastern are shown below. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region aligned with (although PSNH reliability performance is reported as a single company performance metric to IEEE). In recent years, all-in performance in NH Eastern is consistent with second or third quartile performance for SAIDI and SAIFI.

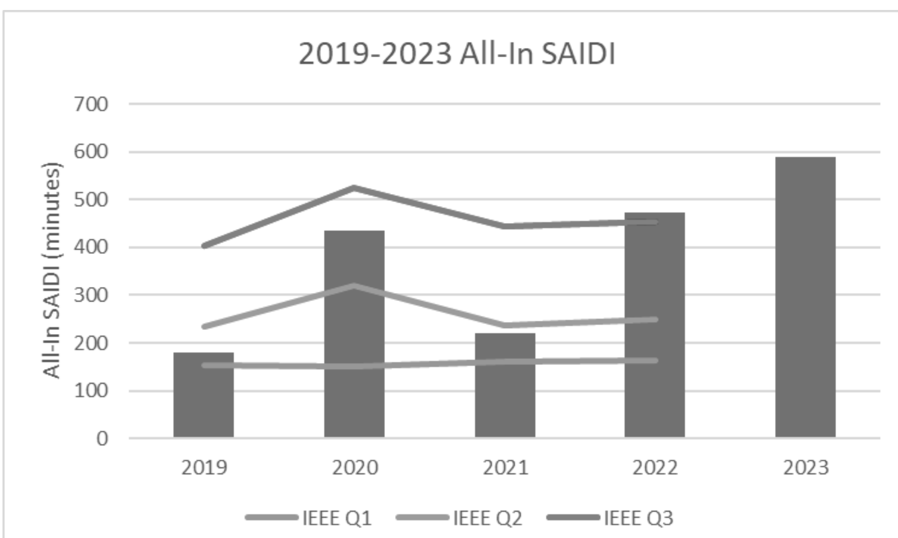


Figure 2-22: 2019-2023 NH Eastern All-in SAIDI and IEEE Quartiles' Threshold Values

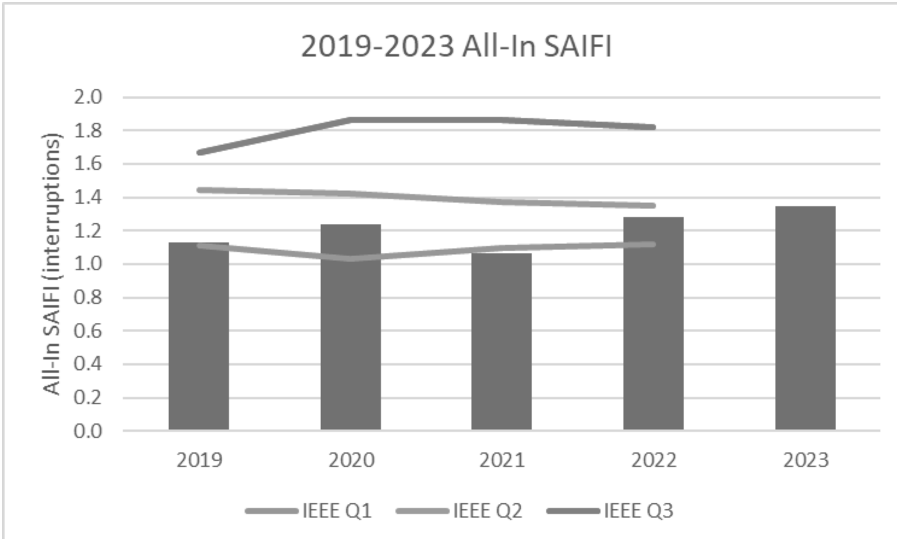


Figure 2-23: 2019-2023 NH Eastern All-in SAIFI and IEEE Quartiles' Threshold Values

2.3.3. Northern Region

The Eversource NH Northern Region consists of three cities (Berlin, Franklin, and Laconia) and all or part of 72 towns (Albany, Alexandria, Alton, Andover, Barnstead, Bath, Belmont, Benton, Bethlehem, Bridgewater, Bristol, Campton, Canterbury, Carroll, Chatham, Chichester, Clarksville, Colebrook, Columbia, Conway, Dalton, Danbury, Dummer, Easton, Eaton, Effingham, Epsom, Errol, Franconia, Freedom, Gilford, Gilmanton, Gorham, Grafton, Haverhill, Hebron, Hill, Jefferson, Lancaster, Landaff, Lisbon, Littleton, Loudon, Lyman, Madison, Meredith, Milan, New Hampton, Northfield, Northumberland, Orange, Orford, Ossipee, Piermont, Pittsburg, Pittsfield, Randolph, Salisbury, Sanbornton, Sandwich, Shelburne, Stark, Stewartstown, Strafford, Stratford, Sugar Hill, Tamworth, Thornton, Tilton, Tuftonboro, Whitefield, and Wilmont) in central and northern New Hampshire served out of 11 bulk substations with a peak electric demand of approximately 276 MW in 2023. This region has a total online DER from all sources of approximately 177 MW, which is the highest relative to the other NH areas. The service area encompasses a population of approximately 149,000 residents and 101,100 customer accounts. Figure 2-24 below is a portion of Figure 2-7 that shows the bulk substation locations (white squares) in the NH Northern region.

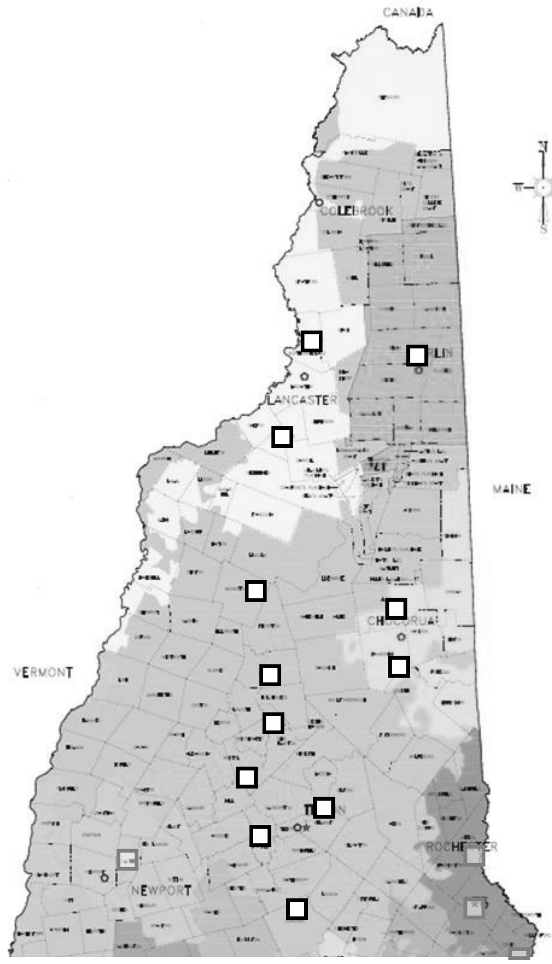


Figure 2-24: NH Northern Region (green areas) Showing Area Work Centers (polygons) and Bulk Substations (squares)

While not part of the Eversource service territory, most of New Hampshire Electric Cooperative's service area is supplied through Eversource's bulk substation facilities and 34.5 kV distribution system from 23 delivery points. Notable areas include the popular tourist destinations of North Conway, Lake Winnipesaukee, Lincoln, and Plymouth. Eversource also provides electric supply to the Ashland Electric Department, New Hampton Village Precinct, and Wolfeboro Municipal Electric Department from the 34.5 kV distribution system.

This region consists of low-load density areas, including: seasonal tourist destinations around Lake Winnipesaukee and the White Mountains including Bretton Woods, Cannon, Gunstock Mountain Resort, and Wildcat Mountain ski areas; medical facilities such as Androscoggin Valley Hospital, Concord Hospital – Franklin, Concord Hospital – Laconia, Upper Connecticut Valley Hospital, and Weeks Medical Center; city, state and federal government offices and services; academic institutions such as Lakes Region Community College and White Mountains Community College; and critical loads such as local municipal water and wastewater treatment facilities.

2.3.3.1 DER Adoption (Battery Storage and PV Solar)

The Eversource NH Northern area has the highest penetration of online DER (64%) as a percentage of the region's peak load and has the highest amount of queued DER (by MW). In fact, when online and in-queue DER are considered together, the total DER capacity would be 129% of the region's peak load (second highest, next to the Western region).

As shown below in Figure 2-25 there is 27 MW of installed solar and less than 1 MW of solar coupled with battery storage. The highest amount of DER online is 55.3 MW of biomass generation, followed by 43.8 MW of diesel and 35.3 MW of hydro generation. The total online DER from all sources is 177.4 MW.[13]

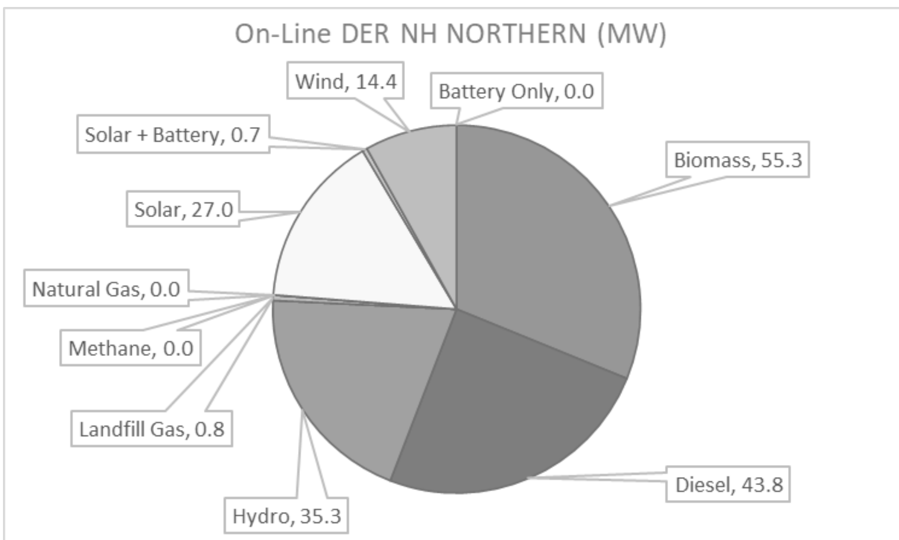


Figure 2-25: NH Northern Online DER by Fuel Type

Figure 2-26 below shows the in-queue DER in the NH Northern 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: 170.6 MW of solar, 8 MW of diesel, 1.3 MW of hydro, 200 kW of solar coupled with storage and about 300 kW of other DER. The total DER in-queue or in the study process is 180.3 MW.

[13] Per latest tracking system extraction.

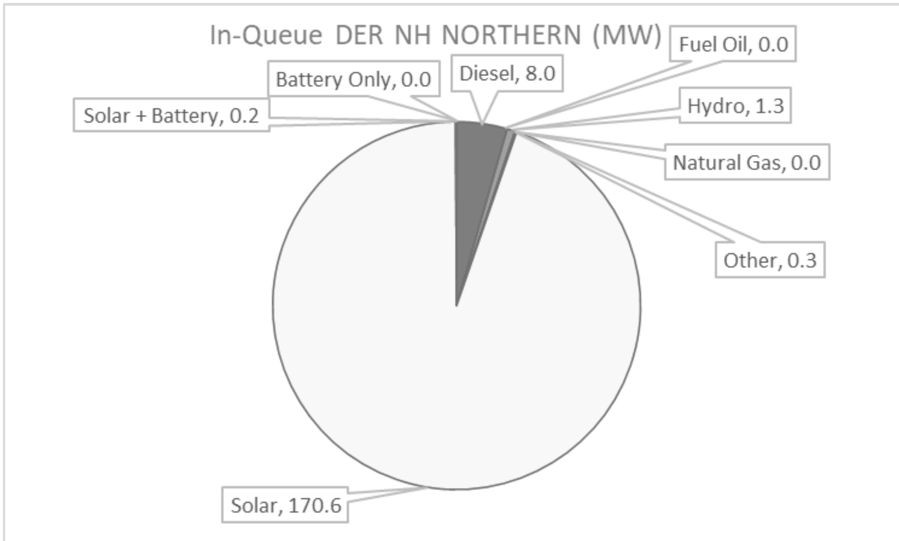


Figure 2-26: NH Northern Queued DER by Fuel Type

2.3.3.2 Substation Capacity Overview

Over the past decade, non-weather normalized bulk substation peak loads in NH Northern Region have ranged between 245 MW and 310 MW as shown in Figure 2-27. Overall nameplate capacity of the substations in this region is presently at 659 MVA. While utilization is at 47% of nameplate capacity, the available headroom ensures system capacity during contingent events when a piece of equipment is removed from service for planned or unplanned work.

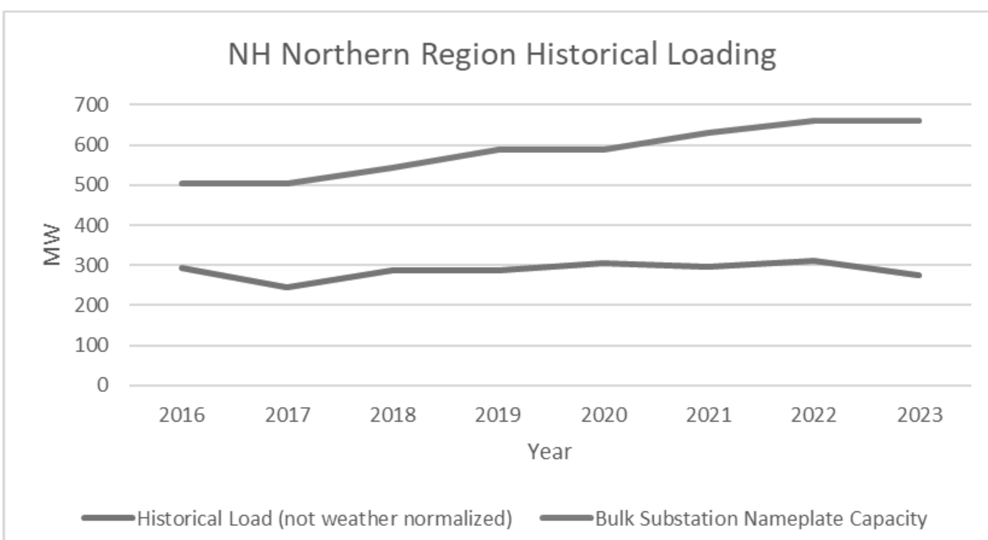


Figure 2-27 NH Northern Region Historical Peak Loading and Bulk Substation Nameplate Capacity

The increasing trend in nameplate capacity for NH Northern Region is due to a variety of circumstances, ranging from electrical system needs stemming from the divestiture of utility-owned generation, capacity needs, and replacement due to asset condition. In the cases where bulk transformer replacements occurred, original transformers were sized at 15 MVA to 20 MVA. With modern standard transformer sizes being 44.8 MVA and 62.5 MVA, there is a significant capacity increase. For substation-level peak loading detail and capacity utilization, see Appendix, Section 8.2.3.

2.3.3.3 Circuit Reliability and Resilience Overview

Section 2.1.5 above includes definitions of commonly used reliability metrics and definitions of blue-sky and All-In performance measures.

Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI per region are shown below as calculated using IEEE rules. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region would align with (although PSNH reliability performance is reported as a single company-level performance metric to IEEE). In recent years, performance in NH Northern is consistent with second or third quartile performance for SAIDI and SAIFI.

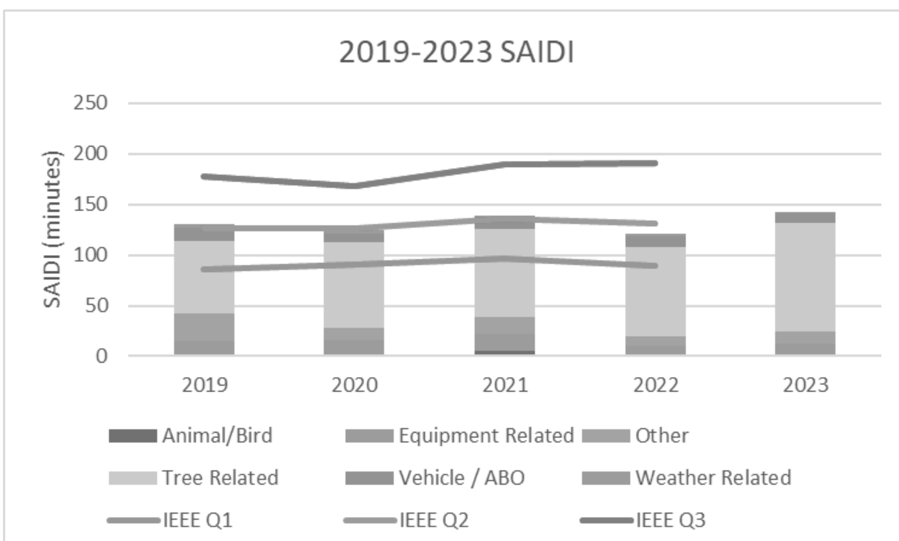


Figure 2-28: 2019-2023 NH Northern Blue-sky SAIDI and IEEE Quartiles' Threshold Values

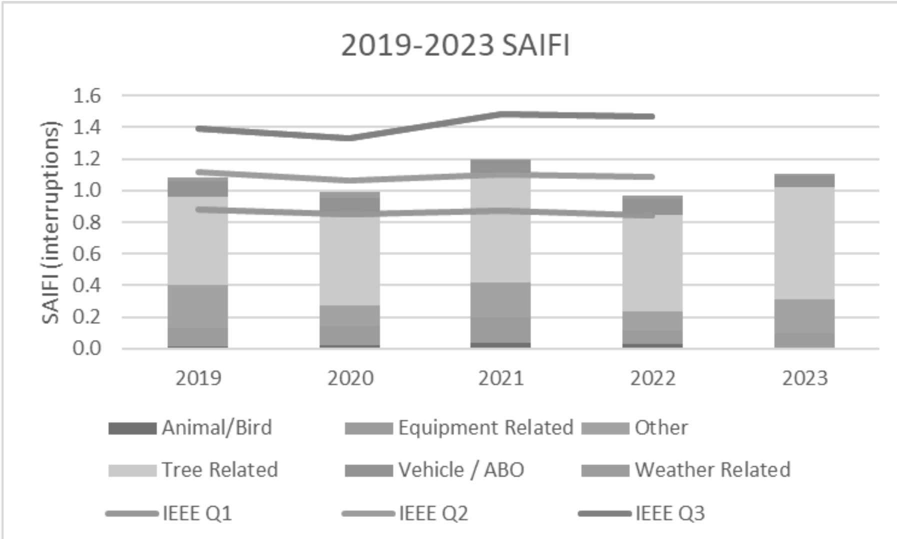


Figure 2-29: 2019-2023 NH Northern Blue-sky SAIFI and IEEE Quartiles' Threshold Values

All-In Performance

All-in SAIDI and SAIFI per region are shown below. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region aligned with (although PSNH reliability performance is reported as a single company performance metric to IEEE). In recent years, all-in performance in NH Northern is consistent with third or fourth quartile performance for SAIDI and SAIFI.

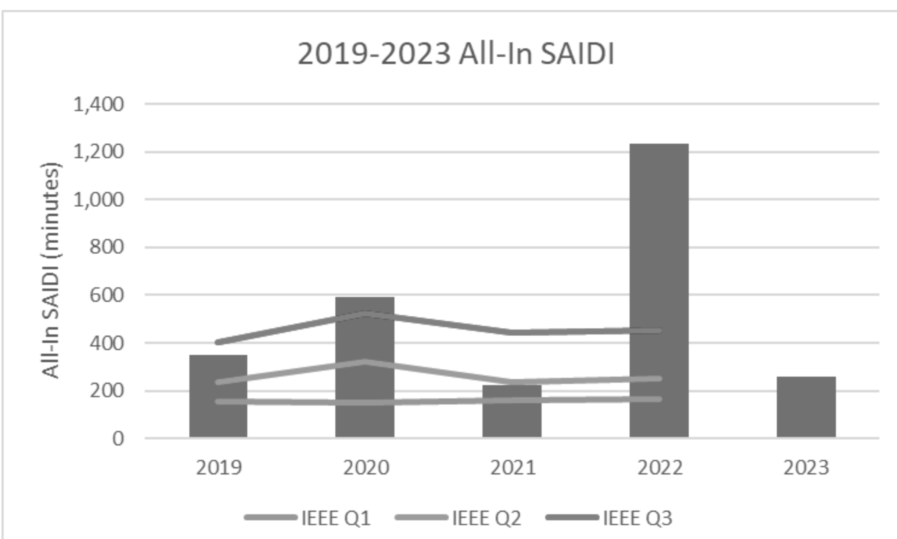


Figure 2-30: 2019-2023 NH Northern All-in SAIDI and IEEE Quartiles' Threshold Values

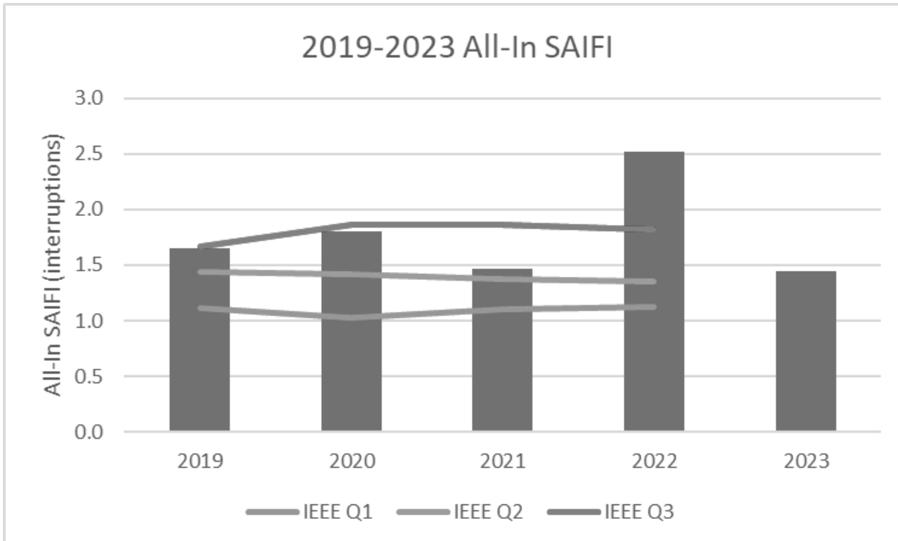


Figure 2-31: 2019-2023 NH Northern All-in SAIFI and IEEE Quartiles' Threshold Values

2.3.4. Southern Region

The Eversource NH Southern Region consists of the city of Nashua and all or part of 25 towns (Amherst, Atkinson, Auburn, Brookline, Chester, Danville, Derry, Greenville, Hampstead, Hollis, Hudson, Litchfield, Londonderry, Lyndeborough, Mason, Merrimack, Milford, Mont Vernon, New Ipswich, Pelham, Peterborough, Sandown, Temple, Wilton, and Windham) in southern New Hampshire served out of 12 bulk substations with a peak electric demand of approximately 495 MW in 2023. This region has a total online DER from all sources of approximately 47 MW. The service area encompasses a population of approximately 288,000 residents and 136,400 customer accounts. Figure 2-32 below is a portion of Figure 2-7 that shows the bulk substation locations (white squares) in the NH Southern region.

Figure 2-32: NH Southern Region (gold areas) Showing Area Work Centers (polygons) and Bulk Substations (squares)

New Hampshire Electric Cooperative has two (2) service areas in Chester and Derry that are supplied by Eversource from its distribution system.

This region consists of low- to medium-load density areas, including: a concentration of medium-to-small commercial and manufacturing in and around Hudson, Merrimack, Milford, and Nashua; two (2) major regional retail districts in South Nashua and along the NH Route 101A corridor between Nashua and Milford; medical facilities such as Parkland Medical Center, St. Joseph Hospital, and Southern New Hampshire Medical Center; city, state and federal government offices and services; academic institutions such as Nashua Community College, Rivier University, and Thomas More College of Liberal Arts; and critical service loads such as Pennichuck Water Works and local municipal wastewater treatment facilities.

2.3.4.1 DER Adoption (Battery Storage and PV Solar)

The Eversource NH Southern area has the lowest penetration of online DER (9%) as a percentage of the region's peak load and has the lowest amount of queued DER (by MW). When online and in-queue DER are considered together, the total DER capacity would still be only 18% of the region's peak load lowest among all regions.

As shown below in Figure 2-33 there is 37.5 MW of installed solar and 1.5 MW of solar coupled with battery storage. Besides solar, the highest amount of DER online is 4.9 MW of hydro generation, followed by 2.4 MW of land fill gas and 500 kW of methane-based generation. The total online DER from all sources is 46.8 MW.[14]

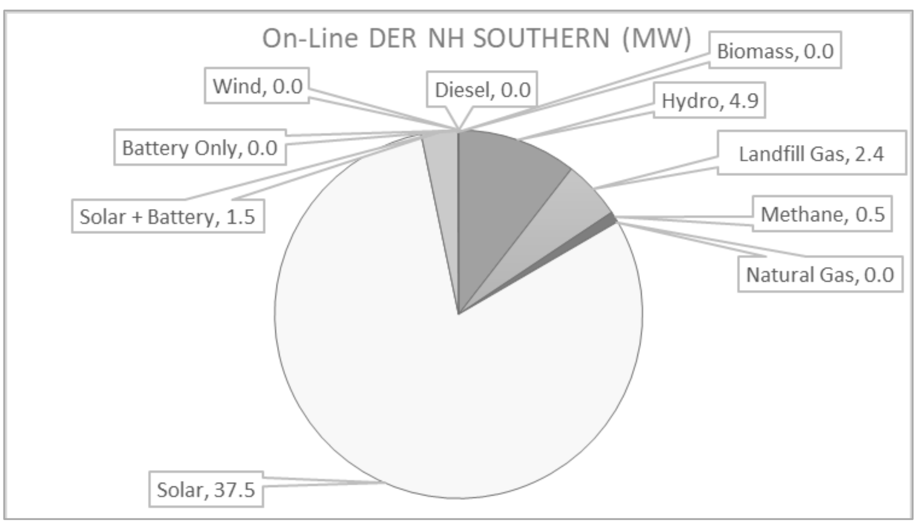


Figure 2-33: NH Southern Online DER by Fuel Type

Figure 2-34 below shows the in-queue DER in the NH Southern region. This includes a significant number of projects with recently completed impact studies that have not been yet

[14] Per latest tracking system extraction.

interconnected, projects in queue, projects in the application stage, or projects in a prescreen stage without a format application submitted yet. These projects include: 65.5 MW of solar, 5.4 MW of solar plus storage, 19.5 MW of standalone battery storage, 12.2 MW of diesel-based generation, 2.5 MW of natural gas, and 1.3 MW of hydro. The total DER in-queue or in the study process is 106.3 MW.

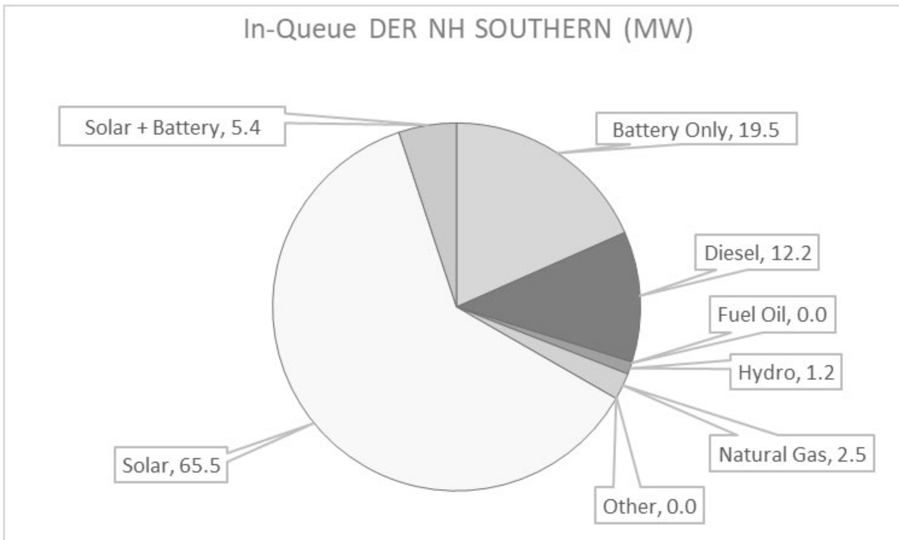


Figure 2-34: NH Southern Queued DER by Fuel Type

2.3.4.2 Substation Capacity Overview

Over the past decade, non-weather normalized bulk substation peak loads in NH Southern Region have ranged between 480 and 530 MW as shown in Figure 2-35. Overall nameplate capacity of the substations in this region is presently at 1089 MVA. While utilization is at 49% of nameplate capacity, the available headroom ensures system capacity during contingent events when a piece of equipment is removed from service for planned or unplanned work.

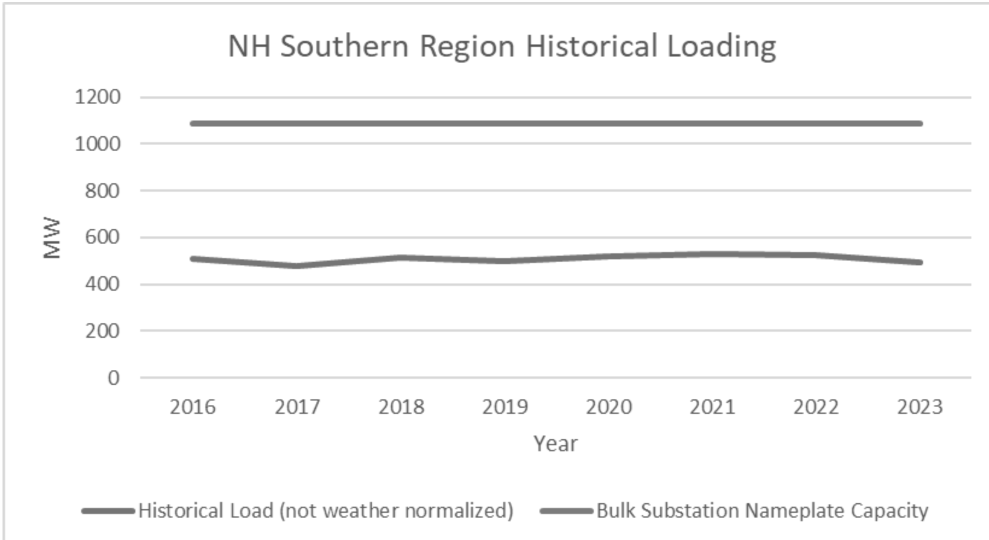


Figure 2-35: NH Southern Regional Historical Peak Loading and Bulk Substation Nameplate Capacity

For substation-level peak loading detail and capacity utilization, see Appendix, Section 8.2.4.

2.3.4.3 Circuit Reliability and Resilience Overview

Section 2.1.5 above includes definitions of commonly used reliability metrics and definitions of blue-sky and All-In performance measures.

Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI per region are shown below as calculated using IEEE rules. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region would align with (although PSNH reliability performance is reported as a single company-level performance metric to IEEE). In recent years, performance in NH Southern is consistent with top quartile performance for SAIDI and SAIFI.

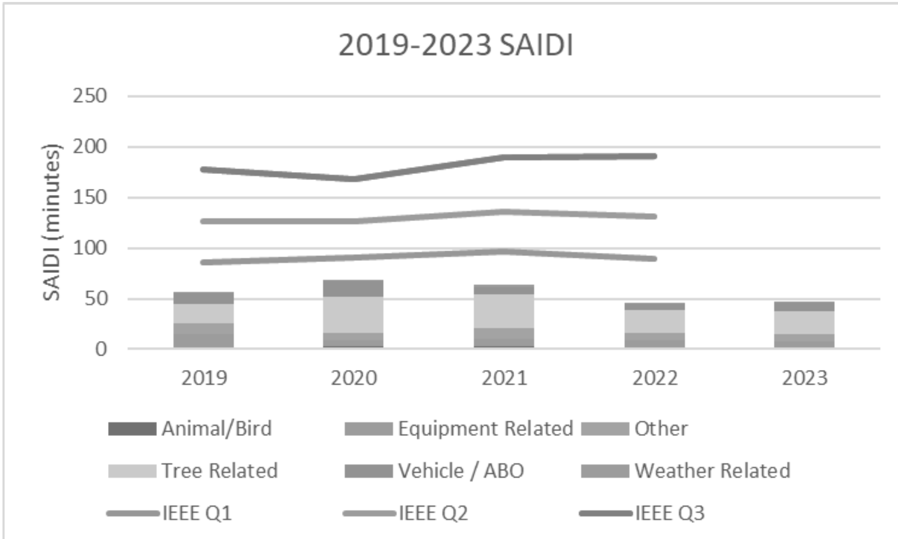


Figure 2-36: 2019-2023 NH Southern Blue-sky SAIDI and IEEE Quartiles' Threshold Values

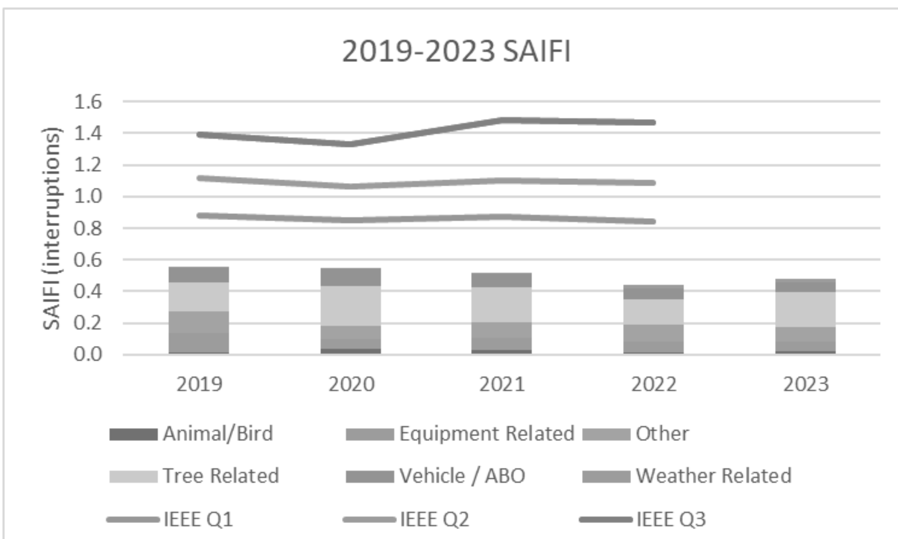


Figure 2-37: 2019-2023 NH Southern Blue-sky SAIFI and IEEE Quartiles' Threshold Values

All-In Performance

All-in SAIDI and SAIFI per region are shown below. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region aligned with (although PSNH reliability performance is reported as a single company performance metric to IEEE). In recent years, all-in performance in NH Southern is consistent with top or second quartile performance for SAIDI and SAIFI.

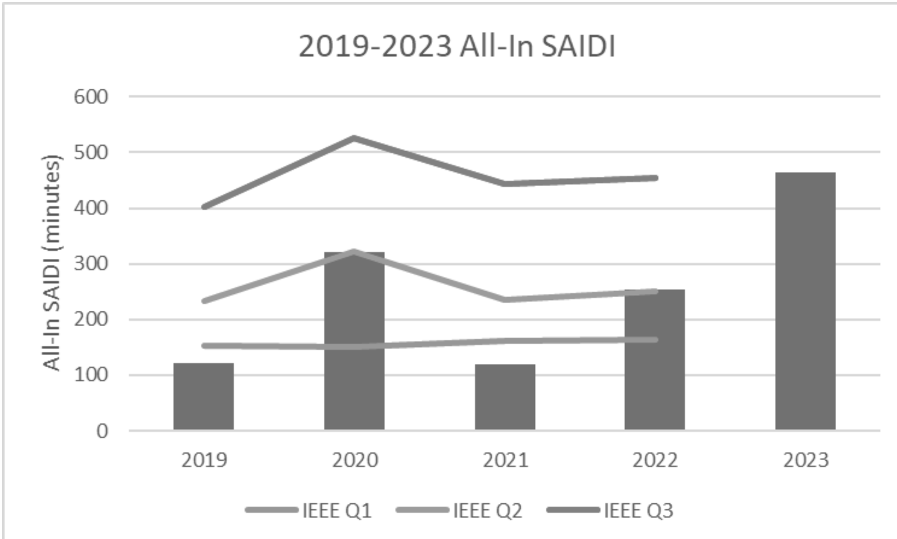


Figure 2-38: 2019-2023 NH Southern All-in SAIDI and IEEE Quartiles' Threshold Values

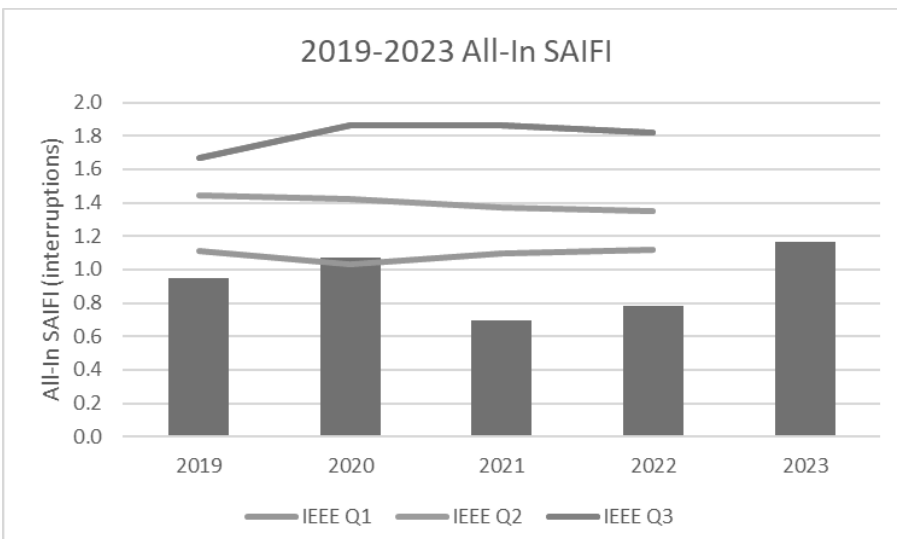


Figure 2-39: 2019-2023 NH Southern All-in SAIFI and IEEE Quartiles' Threshold Values

2.3.5. Western Region

The Eversource NH Western Region consists of two (2) cities (Claremont and Keene) and all or part of 58 towns (Alstead, Antrim, Bennington, Bradford, Charlestown, Chesterfield, Cornish, Croydon, Deering, Dublin, Enfield, Fitzwilliam, Francestown, Gilsum, Goshen, Grantham, Greenfield, Hancock, Hanover, Harrisville, Henniker, Hillsborough, Hinsdale, Jaffrey, Lempster, Lyme, Lyndeborough, Marlborough, Marlow, Nelson, New Boston, New Ipswich, New London, Newbury, Newport, Peterborough, Plainfield, Richmond, Rindge, Roxbury, Sharon, Springfield, Stoddard, Sullivan, Sunapee, Surry, Sutton, Swanzey, Temple, Troy, Unity, Warner, Washington, Weare, Westmoreland, Wilmot, Winchester, and Windsor) in western New Hampshire served out of seven (7) substations with a peak electric demand of approximately 181 MW in 2023. This region has a total online DER from all sources of approximately 87 MW. The service area encompasses a population of approximately 147,000 residents and 74,800 customer accounts. Figure 2-40 below is a portion of Figure 2-7 that shows the bulk substation locations (white squares) in the NH Western region.

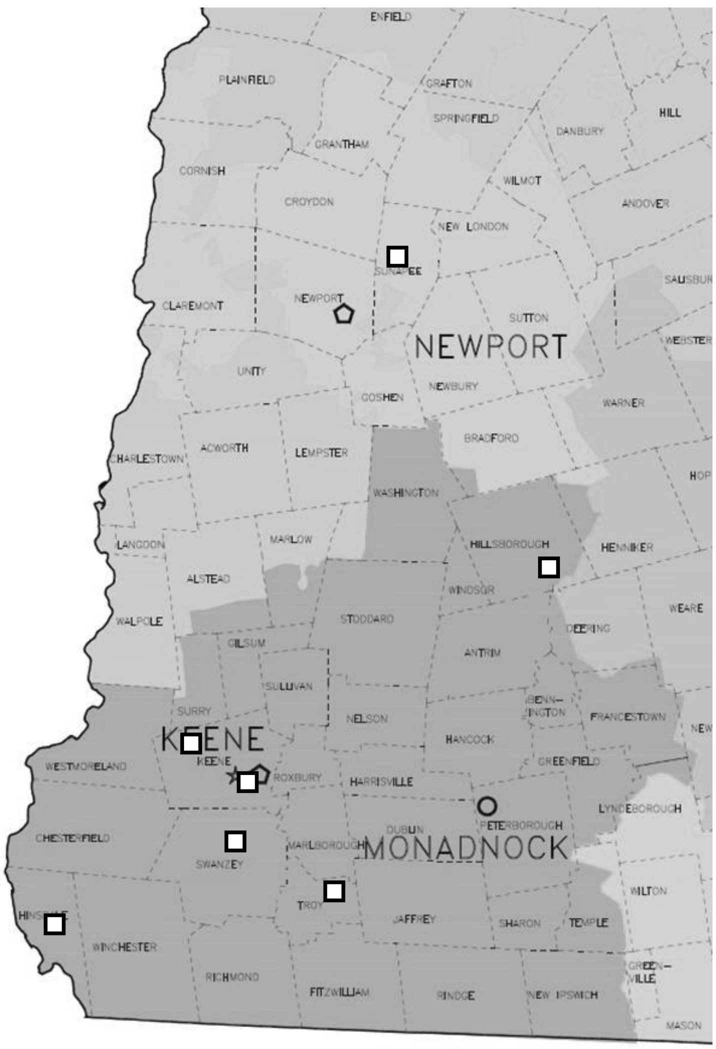


Figure 2-40: NH Western Region (red areas) Showing Area Work Centers (pentagons) and Bulk Substations (squares)

This region consists of low-load density areas, including: many seasonal tourist destinations with lakeside homes, most notable in the region is Lake Sunapee; ski areas of Crotched Mountain and Pats Peak; medical facilities such as Cheshire Medical Center, Monadnock Community Hospital, New London Hospital, and Valley Regional Hospital; city, state and federal government offices and services; academic institutions such as Colby-Sawyer College, Franklin Pierce University, Keene State College, and River Valley Community College; and critical service loads such as local municipal water and wastewater treatment facilities.

2.3.5.1 DER Adoption (Battery Storage and PV Solar)

The Eversource NH Western area has the second highest penetration of online DER (48%) as a percentage of the region's peak load and has the second highest amount of queued DER (by MW). In fact, when online and in-queue DER are considered together, the total DER capacity would be 139% of the region's peak load, highest among all regions.

As shown below in Figure 2-41, there is 27.3 MW of installed solar and less than 1 MW of solar coupled with battery storage. The highest amount of DER online is 24 MW of wind generation, followed by 17.8 MW of biomass and 16.7 MW of hydro. The total online DER from all sources is 86.7 MW.[15]

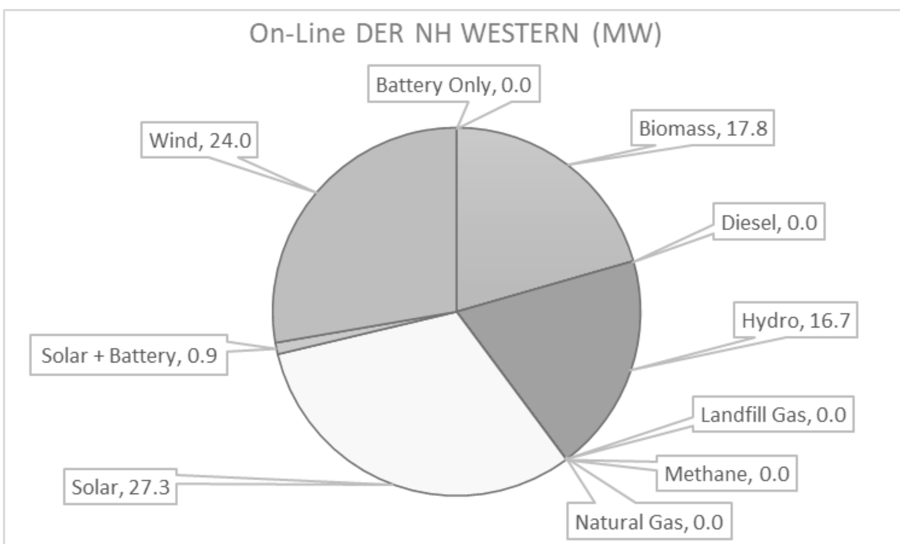


Figure 2-41: NH Western Online DER by Fuel Type

Figure 2-42 below shows the in-queue DER in the NH Western 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: 157.9 MW of solar, 5.2

[15] Per latest tracking system extraction.

MW of solar coupled with storage, 2.4 MW of diesel, and about 100 kW of standalone battery storage. The total DER in-queue or in the study process is 165.6 MW.

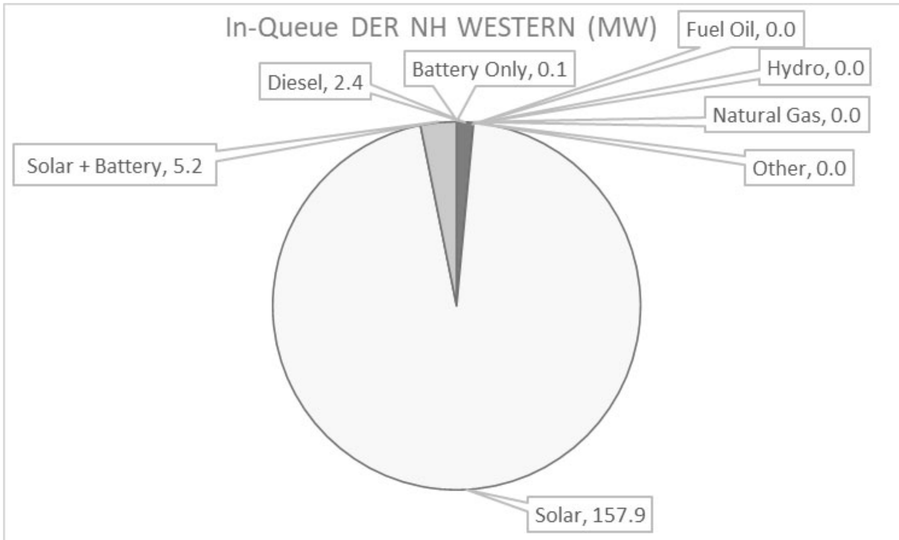


Figure 2-42: NH Western Queued DER by Fuel Type

2.3.5.2 Substation Capacity Overview

Over the past decade, non-weather normalized bulk substation peak loads in NH Western Region have ranged between 160 MW and 190 MW as shown in Figure 2-43. Overall nameplate capacity of the substations in this region is presently at 373 MVA. While utilization is at 51% of nameplate capacity, the available headroom ensures system capacity during contingent events when a piece of equipment is removed from service for planned or unplanned work. The varying nameplate capacity captured in the graph highlights the duration that Eversource plans and prepares for bulk substation projects.

In 2017 a new substation was constructed in Keene to provide additional capacity to the 12 kV distribution system supplying the City of Keene and its surrounding communities. This extra capacity allowed Eversource to remove multiple small, poor-health transformers at Emerald Street Substation, reconstruct the substation facilities with modern equipment. The substation rebuild project was completed in 2021. While it may appear that nameplate capacity overall decreased when Emerald Street was placed in service, that extra capacity was needed during the construction period to allow for reliable service to our customers while accommodating equipment removals for the construction project and any regular maintenance that also needed to occur in the area.

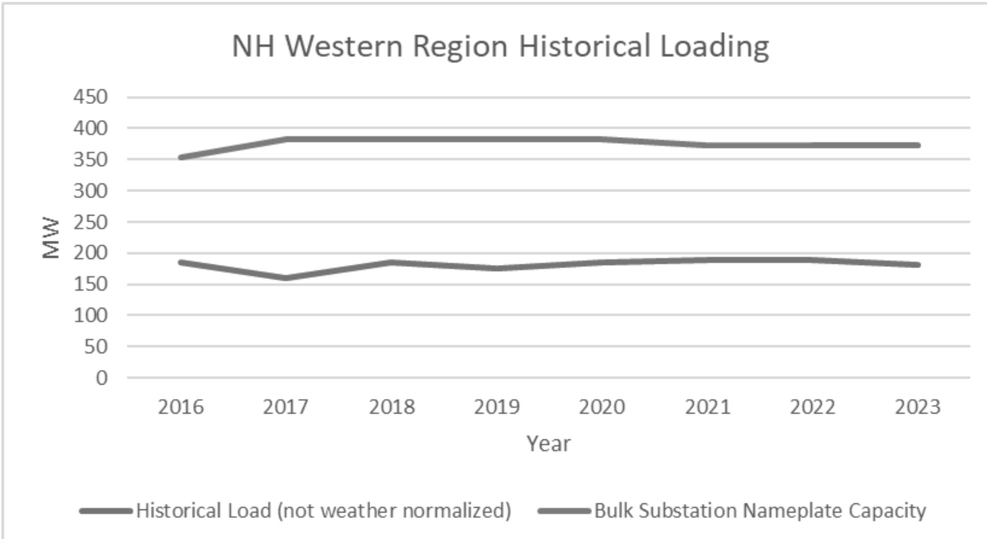


Figure 2-43: NH Western Region Historical Peak Loading and Bulk Substation Nameplate Capacity

For substation-level peak loading detail and capacity utilization, see Appendix, Section 8.2.5.

2.3.5.3 Circuit Reliability and Resilience Overview

Section 2.1.5 above includes definitions of commonly used reliability metrics and definitions of blue-sky and All-In performance measures.

Blue-sky Reliability Performance

Blue-sky SAIDI and SAIFI per region are reported below using IEEE rules. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region would align with (although PSNH reliability performance is reported as a single company-level performance metric to IEEE). In recent years, performance in is consistent with third quartile performance for SAIDI and SAIFI.

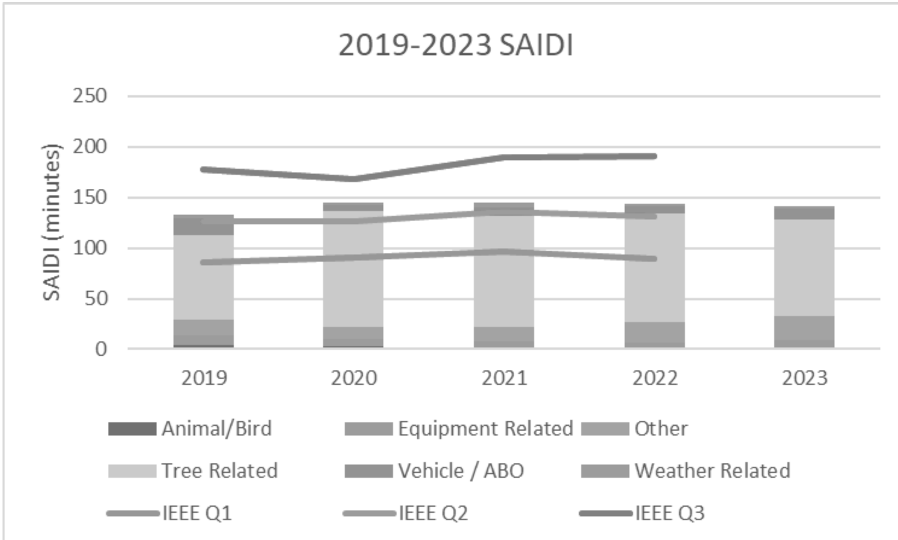


Figure 2-44: 2018-2022 NH Western Blue-sky SAIDI and IEEE Quartiles' Threshold Values

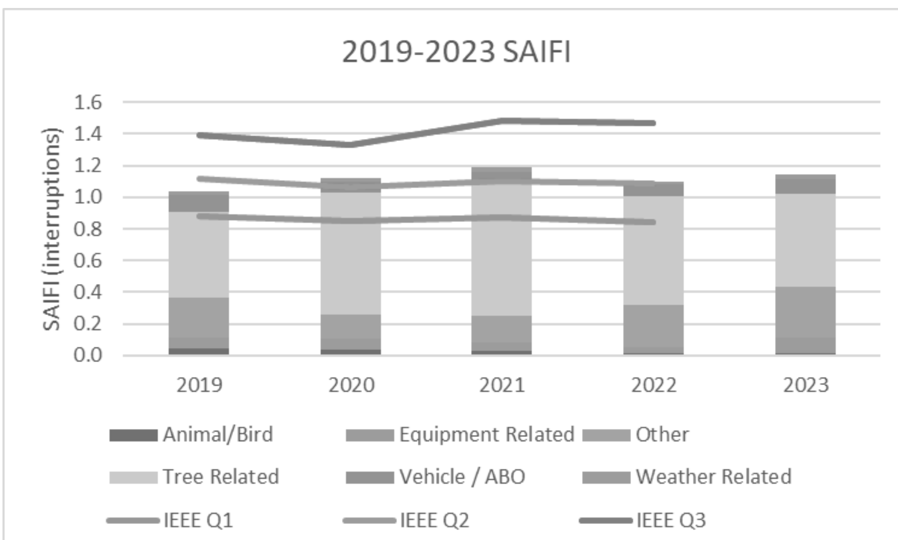


Figure 2-45: 2019-2023 NH Western Blue-sky SAIFI and IEEE Quartiles' Threshold Values

All-In Performance

All-in SAIDI and SAIFI per region are shown below. As a result, the following figures show the Quartile in the IEEE Benchmarking Survey that performance in that region aligned with (although PSNH reliability performance is reported as a single company performance metric to IEEE). In recent years, all-in performance in NH Western is consistent with third or fourth quartile performance for SAIDI and SAIFI.

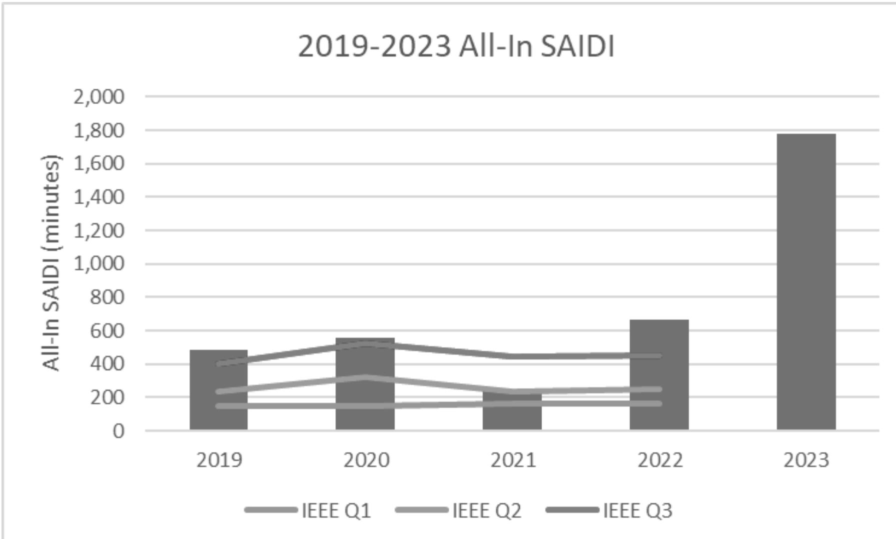


Figure 2-46: 2019-2023 NH Western All-in SAIDI and IEEE Quartiles' Threshold Values

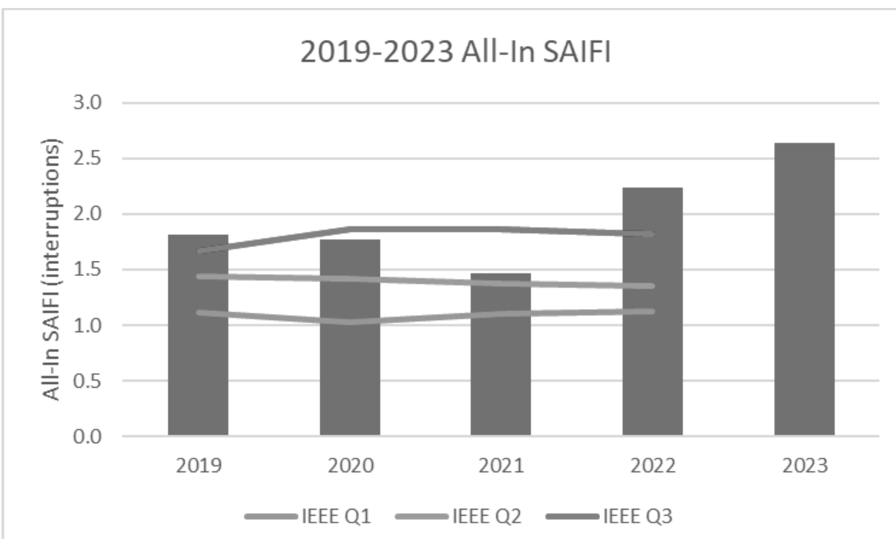


Figure 2-47: 2019-2023 NH Western All-in SAIFI and IEEE Quartiles' Threshold Values

2.4. Cross-Regional Topics

2.4.1. Economic Development

The Gross Metropolitan Product (GMP) for New Hampshire as shown in Table 2-4 below, has averaged 4% growth over the last ten (10) years and has more than recovered after a 3% decline due to the pandemic in 2020.[16] The data also shows that Real Household Income has maintained just over 1.7% growth over the last ten (10) 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 6% decrease during the pandemic, Total Employment has fully rebounded to pre-pandemic levels and maintains an average 1% growth over the last ten (10) years. The Unemployment Rate has continued to drop at an average rate of 6.7% over the last ten (10) years, despite doubling in 2020. Housing Starts continues to steadily increase and average a 5% increase over the last ten (10) years. Overall, economic indicators suggest a positive outlook and growth, which is accounted for in the load forecasting process in Chapter 4.

Table 2-4: New Hampshire Historic Economic Development

New Hampshire Economic Statistics*										
	Gross Metro Product		Real Household Income		Total Employment		Unemployment Rate		Housing Starts	
2014	73		133,387		643		4.3		2,987	
2015	77	4.7%	135,537	1.6%	654	1.6%	3.4	-26.7%	3,461	13.7%
2016	80	3.4%	137,335	1.3%	666	1.8%	2.9	-18.8%	3,762	8.0%
2017	81	2.0%	141,057	2.6%	673	1.1%	2.8	-1.9%	3,866	2.7%
2018	84	3.2%	144,262	2.2%	678	0.7%	2.6	-6.8%	4,301	10.1%
2019	87	4.1%	150,088	3.9%	684	0.9%	2.6	-2.3%	4,356	1.3%
2020	89	1.3%	157,995	5.0%	639	-7.0%	6.7	61.7%	4,163	-4.6%
2021	99	10.6%	162,679	2.9%	663	3.6%	3.4	-97.3%	4,823	13.7%
2022	105	5.6%	156,637	-3.9%	687	3.5%	2.5	-35.3%	4,567	-5.6%
2023	110	4.7%	157,382	0.5%	700	1.8%	2.1	-16.8%	5,015	8.9%
CAGR '14-'23		**4.2%**		**1.7%**		**0.8%**		**-6.7%**		**5.3%**
**Source: Moody's Analytics data for New Hampshire*										

[16] 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.

2.4.2. Aggregate DER Impacts

From Table 2-3, above, it can be seen that the combined amount of on-line and queued DER in the Northern and Western regions exceeds the regional peak load. This indicates that as more and more of the queued DER comes on-line there is a possibility for power to flow from the distribution system up on to the transmission system, especially during periods of light load and high DER output. This could potentially have an impact on the Bulk Power System (BPS). To ensure that the DER aggregation does not have an adverse impact to the BPS Eversource, along with other utilities and ISO-NE have continuous coordination between distribution and transmission entities to assess the potential impact of DER on the BPS.

On the distribution system, DER aggregation with a high enough penetration could lead to loading of bulk and non-bulk substation transformers (during reverse flow) beyond substation transformer thermal capacity limits. This could lead to either replacement of the transformer with a larger sized unit, addition of a transformer to the substation, or in rare cases, construction of a new substation. Unfortunately, major substation upgrades may prove prohibitively expensive for a single developer and lead to free ridership if implemented, therefore it is not uncommon to see the queue stagnate when substations are saturated to the point where major upgrades are needed. Section 5.1.3 discusses potential solutions to these issues that have been considered and adopted in other states.

2.4.3. Electrification Trends

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 NHSaves or tap into other funding sources. Therefore, reported electrification numbers may be underestimating actuals.

2.4.3.1 Heating Electrification

Heating electrification has not had a measurable impact on the overall system load to date. While heat pumps in the residential sector have been viable for several decades, overall adoption rates were low until now. Eversource does not currently have insight into how many heat pumps were installed at homes that are outside of the NHSaves programs. Currently, residential space heating is comprised of mainly fuel oil (45.5% of homes), natural gas (19% of homes), and propane (16.4% of homes). Delivered fuel legacy heating systems are considered prime candidates for heating electrification. ISO-NE projects as much as 80% of homes heated by oil and propane may convert to electric heating by 2050.[17]

2.4.3.2 Electric Vehicles

Table 2-5, below, shows the current Electric Vehicle (EV) breakdown for Light Duty Vehicles (LDV) in New Hampshire by EV type. The data highlights the fact that EV deployment in this region is still in the nascent stage, with full EVs and PHEVs accounting for less than 1% of LDVs in the region. In 2023, New Hampshire saw the EV stock increase by an estimated of 3,487 vehicles. ISO-NE projects that as much as 25% of LDV vehicle stock will be electric by 2033 in New Hampshire.[18] Even with slower native EV growth, transportation electrification infrastructure needs in New Hampshire will be influenced by visitors, particularly tourists, needing to charge their EVs.

Eversource continues to participate in state run programs, such as the National Electric Vehicle Infrastructure (NEVI) through NHDOT, as well as Granite State Clean Fleets through NHDES. Four Projects were conditionally awarded within the NEVI program, three of which are in Eversource's service territory. Eversource continues to work with private sector driven electrification projects, such as Amazon's Electric Fleet charging station in Hooksett, and Target's Distribution center with provisions for Electric Trucking charging stations in Hudson.

Overall, the Company's analysis of the total potential for charging in New Hampshire, in Figure 2-48, indicates that full electrification would sum to 2.8 GW of load to the system with the most significant contribution expected from electrified medium duty vehicle fleets and light duty vehicles. The Company is proposing as part of its filing to invest into advanced forecasting capabilities similar to other jurisdictions that would allow it to develop extremely detailed forecasting and modeling capabilities to understand these impacts on the New Hampshire system and integrate future electrification need where appropriate into other capital projects and harness efficiencies.

Table 2-5: EV Count For New Hampshire

Vehicle Type	2022 Registrations[19]	% of Vehicles[20]
Full Electric (EV)	7,000	0.5%
Plug-In Hybrid Electric (PHEV)	4,800	0.3%
Hybrid Electric (HEV)	31,100	2.3%

[17] ISO New England. "Final 2024 Heating Electrification Forecast", April 2024. https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf
[18] ISO New England. "Final 2024 Transportation Electrification Forecast", April 2024, https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf
[19] US Department of Energy. "2022 Light-Duty Vehicle Registration Counts by State and Fuel Type" https://afdc.energy.gov/vehicle-registration
[20] US Department of Energy. "Electric Vehicles Registered in 2022" https://afdc.energy.gov/transatlas#/

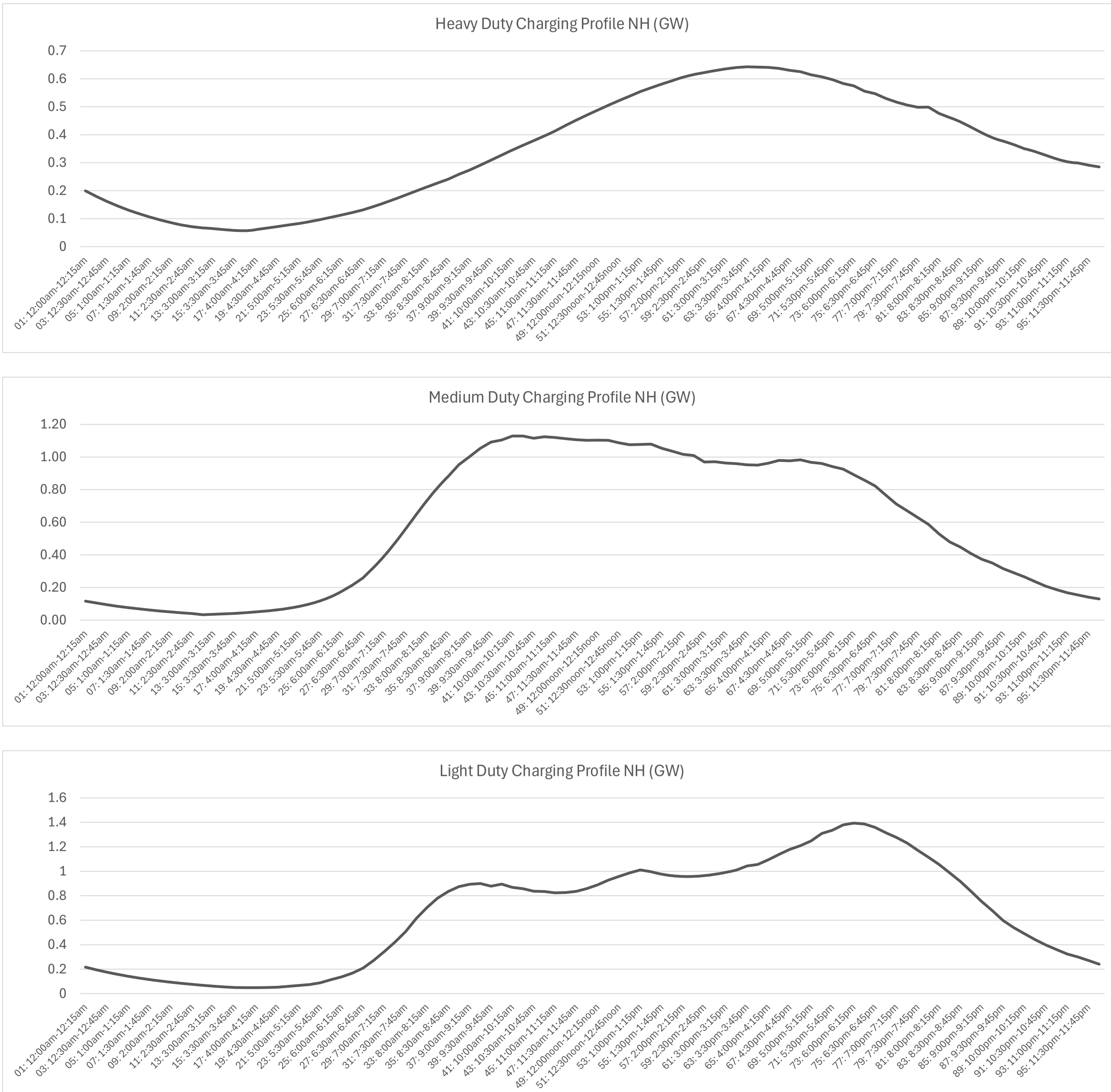


Figure 2-48: Analysis of Total Potential for Charging in New Hampshire

2.4.4. Grid Services

2.4.4.1 Demand Response

In 2023, the Company achieved 6.5 MW of savings from Active Demand Response, delivered through the NHSaves programs, in all of New Hampshire.

2.4.4.2 DER Integration

The Company has a robust process to ensure all solar, batteries and other DER are safely and reliably interconnected to the distribution system. The Company is currently investigating technologies for standardized remote communication and control of customer DER facilities over 500 kW for enhanced situational awareness and reliable real time system operations. This capability will also enable lower cost flexible interconnections whereby the interconnecting customer agrees to an operational schedule that reduces the need for some system modifications that otherwise would have been required to ensure reliability. In the future, the presence of DER standardized communication and control technology would allow a DER facility to offer grid services such as peak load reduction, frequency control, or voltage support based on an agreement with the Company.

In addition to DER communication and control technology, the Company is currently investigating the use of smart inverter controls as part of the DER interconnection process, but this is not a feature of the current state of the system. However, the Company's Massachusetts affiliate has successfully demonstrated smart inverter control capability and algorithms, specifically on its Energy Storage System (ESS)-based microgrid in Provincetown, MA. The Provincetown 25 MW/38 MWh ESS project is a unique application of grid-forming inverter technology to improve the reliability and resiliency in the Lower Cape Cod area.

For a contingency outage event where the transmission or distribution supply to the area is disrupted, an ESS of this type can transition from grid-connected mode to islanded mode seamlessly to serve area load and minimize sustained customer interruptions. The ESS would need to be equipped with grid-forming inverters to supply nominal voltage at 60 Hz to customers in place of the grid. Grid forming inverters can provide a voltage and current reference in islanded mode (or disconnected from the grid) to enable stable, secure operation of a microgrid which can continue to serve customer load during a grid outage. Without the grid-forming inverters, the ESS will be unable to operate off the grid, and microgrid operation will be impossible if connection to the source is lost.

The Company continues to evaluate opportunities to develop ESS projects, using smart inverter controls, for applicable use cases, including reliability and resiliency, in New Hampshire.

2.4.5. Aging Infrastructure

2.4.5.1 Substation Transformers

There are 186 substation transformers in all of NH (Central, Eastern, Northern, Southern, and Western Regions), 83 bulk station transformers and 103 distribution station transformers. The following chart shows the age of 186 substation transformers with age records. Of the population of NH distribution station transformers with age records, 15% are older than 60 years and 32% are less than 20 years old.

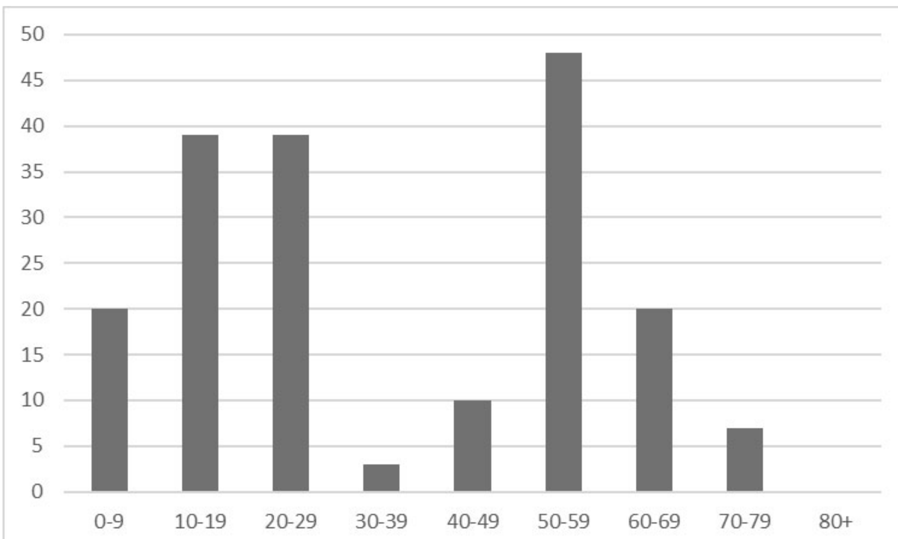


Figure 2-49: Age of the NH Bulk and Distribution Substation Transformers

Although traditional transformer replacement has been typically driven by age of fleet, it is not optimal to base the replacement strategy on age of the asset alone. In order to efficiently manage the aging infrastructure, the Company has adopted a different approach that accounts for other factors such as transformer nameplate, oil quality analysis data, and dissolved gas composition. This provides a methodical way to look at asset conditions and compare the conditions to the corresponding failure consequence resulting in a final asset health database. The asset health data is associated to the system data to capture the impact of transformer loss on the system, enabling the Company to assess severity. Based on health and system factors, the Company is able to make replacement prioritization.

2.4.5.2 Breakers

There are 475 distribution station breakers currently in service in all of NH (Central, Eastern, Northern, Southern, and Western Regions). The following chart shows the age of the 475 breakers in decadal buckets. NH breaker population includes 58 breakers or 12% are at or over

50 years old and 113 breakers or 24% are under 10 years old. There are no breakers currently in service that are older than 79 years old.

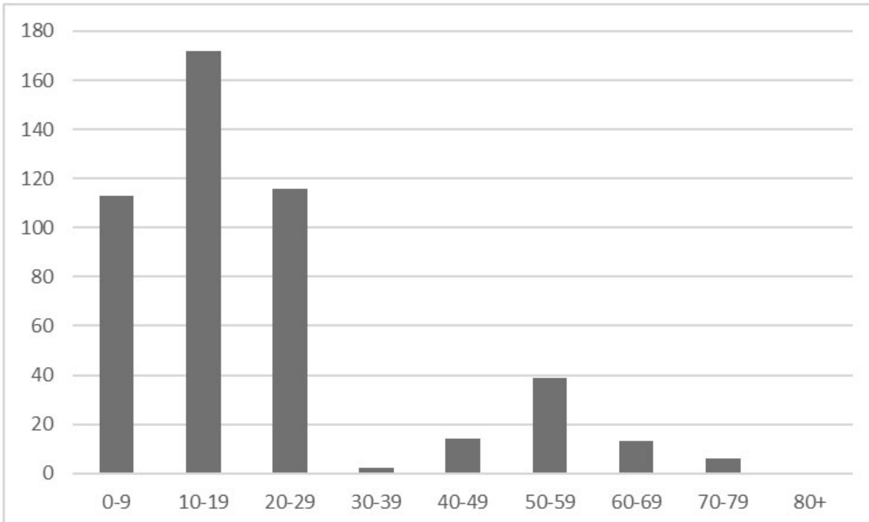


Figure 2-50: Age of the NH Distribution Substation Breakers

2.4.6. Distribution Automation/Telecom

The NH Distribution Automation program and associated telecom network is the foundational layer of remote control and monitoring that is used by control room operators to operate the distribution system safely, reliably, and optimally. This network of field devices consists of over 1900 "smart" switches. These devices provide status and measurement information of the distribution grid in NH. They are placed along distribution circuits to reduce the number of customers in any given segment of circuit as well as at key operational points on a circuit. The information provided by these devices is then transmitted across a field area network (FAN) that uses both radio and cellular means to create connectivity. The radio network in NH was designed and implemented to support large scale deployment of devices and the associated data that would need to be transmitted. In the past 10 years, 10 new radio towers were built and commissioned. These towers increase the data radio coverage by 200%. In addition, a standard equipment design for the use of cellular communications was also established. This provided an additional option for areas where radio coverage was not sufficient. The communications network still has needs to ensure that proper coverage, reliability, and data throughput are available for the field devices that are required to operate the grid safely, reliably, and optimally.

2.4.7. Technology Platforms

The Company is utilizing advances in technology to build and operate a smarter, flexible, and resilient grid. The changing nature of the grid with increased automation driving operational complexity requires 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) storm response; (5) asset management; and (6) data analytics.

2.4.7.1 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 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 1,300 substation devices in its eECS. Field devices, such as reclosers and switches, typically communicate to the eECS via private radio or cellular communications. The Company has over 1,900 intelligent field 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.

The Company initiated an upgrade of its NH transmission and distribution SCADA system in 2024 that will be completed in 2025. This upgrade will ensure the system is using current technology that is secure and capable of cost-effective maintenance. The SCADA upgrade project will also add an operational forecasting tool to predict load and generation in real time based on weather conditions. The forecast will be defined for the day ahead and also intra-day as the distribution system can potentially change drastically due to outage events, system maintenance, and power flow conditions. It also needs to will also be presented as actionable information to system operators.

2.4.7.2 Distribution Management System (DMS)

The Distribution Management System (DMS) is a software solution for real-time management of distribution networks. It is a suite of applications designed specifically to meet the needs of an electric distribution utility. DMS presents information in a way that allows for enhanced situational awareness on the distribution network, as well as tools to manage the network effectively. DMS provides an integration of the distribution network view with other systems, such as real-time SCADA and EMS (Energy Management System) displays.

The DMS is foundationally built from Geographic Information System (GIS). Additional data is also required to support load flows calculations and other advanced functions. This includes engineering data such as impedances, winding configurations, operational limits, and device settings. It also includes customer information, historical loading, and DER data.

Customer Loads are critical to the DMS power flow solution for proper allocation. Currently the loads are based off historic customer billing and a custom algorithm to convert monthly kilowatt-hours to kW and kVAR. Additionally, large customers are not billed utilizing the same process and manually managed. These large customers have a significant impact on the power flow calculations.

Capacitor and voltage regulator statuses are also critical for accurate model convergence. Without proper telemetry, the DMS utilizes local settings and the calculated flows which may not be exact due to small deviations in the system and transformer ratio accuracy. Typical voltage regulator positions differ by 0.625% and capacitor sizes at 2400 KVAR.

SCADA telemetry is key to the success of the DMS advanced applications. The majority of pole top reclosers on the electric system provide sufficient SCADA data. Unfortunately, substation circuit breakers lack the same level of data that the pole top reclosers provide. Approximately 75% of all substation circuit breakers in New Hampshire lack the data required for advanced applications including Loss of Voltage FISR, FISR, Fault Location, and Volt-VAR Optimization. See Section 5.2 for a description of substation automation upgrades and Section 5.4.1 for a description of planned investment in capacity and voltage regulator automation.

Currently in the State of New Hampshire, Eversource has in place a DMS with the following Distribution Network Advanced Functions of Fault Isolation and Service Restoration (FISR) and Planned Outage Study. An upgrade of the DMS system will be completed in 2025.

2.4.7.3 Fault Isolation and Service Restoration

The FISR application generates switching plans to isolate faulted sections and to restore service to non-faulted sections. Along with other switching capable Distribution Network Advanced Functions (DNAF) applications, FISR can be ran with three levels of automation: Advisory, Semi-Auto, and Closed-Loop. In Advisory mode, FISR will generate one or more plans, but take no action. Semi-Auto enables letting operators implement or reject the FISR plans. In Closed-Loop, FISR will automatically complete the switching steps of the most highly ranked plan, without operator action.

FISR uses a problem formulation that defines one or more operational objectives. The standard formulations are minimizing unserved kW, minimizing customer minutes interrupted, minimizing the number of switching operations, and minimizing voltage drop along the reconfigured feeders.

The problem formulation also specifies the network and operational constraints, including branch flow limits, load, bus voltage limits, and relay settings. These formulations can all be modified to change prioritization of over two dozen parameters. Currently, NH DMS utilizes the "Minimum Customer Minutes Interrupted" problem formulation and currently has a success rate of 85%. The remaining is addressed in a newer version of software (currently being upgraded with an in-service date of Q2 2025).

2.4.7.4 Planned Outage Study

The Planned Outage Study (PLOS) application generates plans to isolate a component, minimizing the number of interrupted customers. PLOS is a study-mode-only application. The PLOS application uses methods similar to the FISR application for generating the switching plans. PLOS also utilizes the same problem formulations as FISR. The only major difference is that PLOS first transfers the affected load and then isolates the component to be taken out of service to prevent the unnecessary dropping of load.

In NH, a custom modification has been implemented to allow distribution system operators to easily coordinate the DMS electrical loads with Independent System Operator New England (ISO-NE) forecasted system peaks.

Currently, PLOS is in Advisory mode and triggered when a requested outage permit is submitted to system operations.

2.4.7.5 Outage Management

The Company's Outage Management System (OMS) is a detailed network model of the distribution system. The utility's 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.

2.4.7.6 Geographic Information System

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. In 2024, the Company completed an upgrade of its GIS platform, transitioning to a new software vendor with a new data model and updated symbology used for operational mapping.

2.4.7.7 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.

2.4.7.8 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 time and 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.

2.4.8. Energy Efficiency

As an NHSaves utility program administrator, Eversource offers energy efficiency programs across all customer segments, including residential customers of all income brackets including funds dedicated to income-eligible programming, municipalities, 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 NHSaves programs began its current energy efficiency cycle with a comprehensive three-year plan spanning 2024-2026. The Company's portion of the 2024-2026 budget calls for an investment of over $158 million in energy efficiency and active demand response. The NHSaves energy efficiency efforts are primarily focused on reducing load on the electric and natural gas distribution systems and the Plan also expands the existing active demand response pilots into full programs with larger budgets to further target load curtailment during the ISO-NE system peak.

In addition to incorporating changes in codes and standards over time, NHSaves regularly monitors adoption rates for technologies including new and emerging measures and reviews existing assumptions to ensure the savings claimed within the programs are fact-based and validated and offerings are continuously aligned with current market dynamics. Additionally, the NHSaves programs routinely collaborate with other complementary efforts throughout the state to maximize the impact of the programs. Partners include the Community Action Agencies, the Weatherization Assistance Program (WAP) and state agencies including the New Hampshire Department of Energy (NH DOE) and New Hampshire Department of Environmental Services (NHDES). The partnerships also increase customer awareness of and access to energy efficiency funding and resources within the state. Eversource remains dedicated to its award-winning administration of the NHSaves programs and is optimistic that the 2024-2026 Plan will continue to deliver impactful energy savings to New Hampshire customers and the corresponding benefits to the electric distribution system.

3.0 Distribution Planning Process

3.1. Integrated Planning Overview

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.

From an overall perspective, bottoms-up integrated transmission and distribution (T&D) planning within Eversource begins with the forecast of distribution net load at the bulk substation-level (accounting for native load growth, large commercial developments, DER and EV adoption and energy efficiency) over a ten-year period, as depicted in Figure 3-1 below.

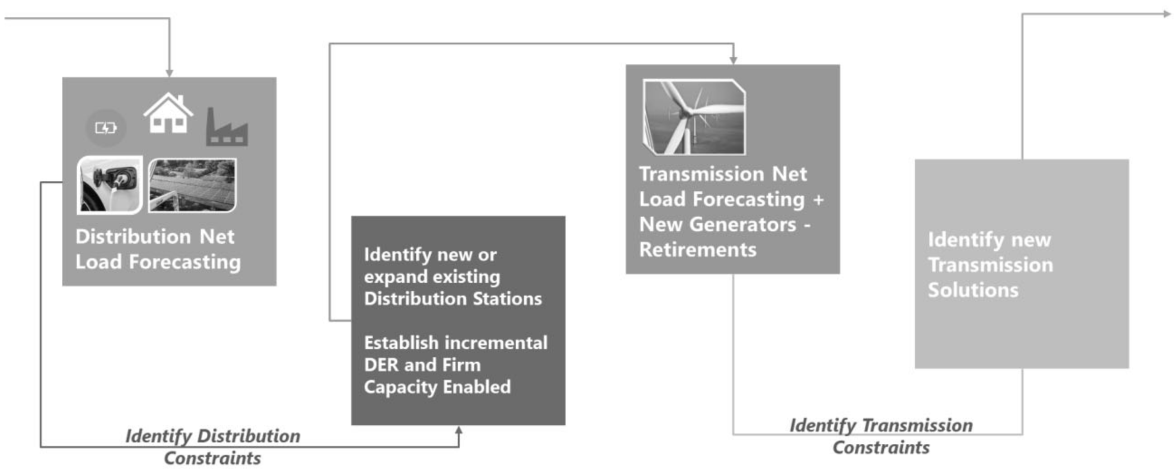


Figure 3-1: Bottoms -Up Approach to Integrated T&D Planning

The load forecast is then used in detailed system models to identify planning criteria violations and distribution constraints under several planning scenarios. To resolve these project violations, distribution solutions, including system expansion and new facilities are developed, which then create additional capacity to enable further load growth and DER adoption. The forecasted distribution growth, incremental enabled capacity, as well as generation portfolio changes are used to model, simulate and identify constraints on the transmission system and reliability needs for suppling bulk substation loads. Transmission-level projects and solutions are then developed to address these needs and enable safely reliable service to all customers.

Distribution bulk substation projects involve collaboration with the Independent System Operation of New England (ISO-NE). There is also an annual reporting of projects involving bulk distribution substations via the Local System Plan, which is provided to stakeholders. These projects are required to be evaluated by Eversource and approved by ISO-NE to ensure that there is not an adverse impact to the reliability or operation of the transmission system.

The System Planning group within Eversource is primarily responsible for system performance evaluation to develop substation capacity-driven and reliability-driven projects based on N-1 contingency needs. However, the full scope of the integrated distribution plan requires extensive collaboration and coordination with several other groups and functions, as depicted in Figure 3-2 below.

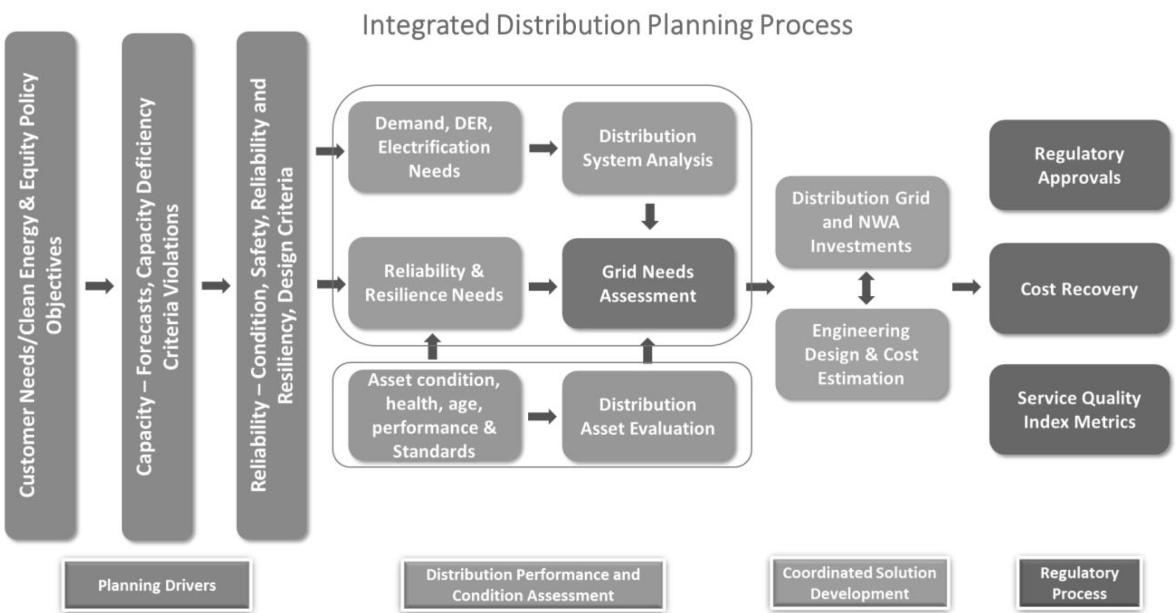


Figure 3-2: Integrated Distribution Planning Process

Some of these key groups and functions that inform and influence integrated planning include:

- Advanced Forecasting – identifies load drivers and adoption trends and develops granular 10-year forecasts and long-term demand assessments at the station level to identify system constraints.
- Distribution System Planning – assumes responsibility for identifying substation capacity and voltage constraints and developing system investment plans to address violations.
- DER Planning – assesses customer interconnection requests for large installations and develops investment plans to safely and reliably accommodate the DER.
- Reliability and Resiliency Planning – uses data and models to identify poor performing circuits and resiliency risks and develops targeted improvement measures at a zonal level.

- Transmission System Planning – identifies transmission constraints and reliability requirements for supplying distribution bulk substations across local and regional networks.
- Asset Management – identifies asset condition projects and programs, utilizing asset data, inspection reports, and history for all substation assets in the NH electrical system.
- Distribution Engineering – assumes responsibility for identifying line capacity and voltage constraints and developing system investment plans to address violations.

The process starts with planning drivers, including customer needs, state energy policy objectives, capacity and reliability needs which feed into various distribution analysis methods shown in green. These four boxes capture the performance evaluation aspect of distribution planning. The methodologies used for distribution performance evaluation are shown in Figure 3-3. Feeding into this evaluation and informing the plan are aspects of asset health condition, distribution standard violations and other distribution asset needs that are co-optimized with capacity and N-1 reliability needs. These are shown in the brown boxes in Figure 3-2. The coordinated evaluation of distribution needs feed into the final grid needs assessment for which co-optimized solutions and alternatives (including non-wires solutions) are developed. For each engineering design is performed, cost estimates are developed, and construction plans based on need dates and lead time considerations are developed and submitted to the Eversource Capital Project Approval process, which is described in more detail below.

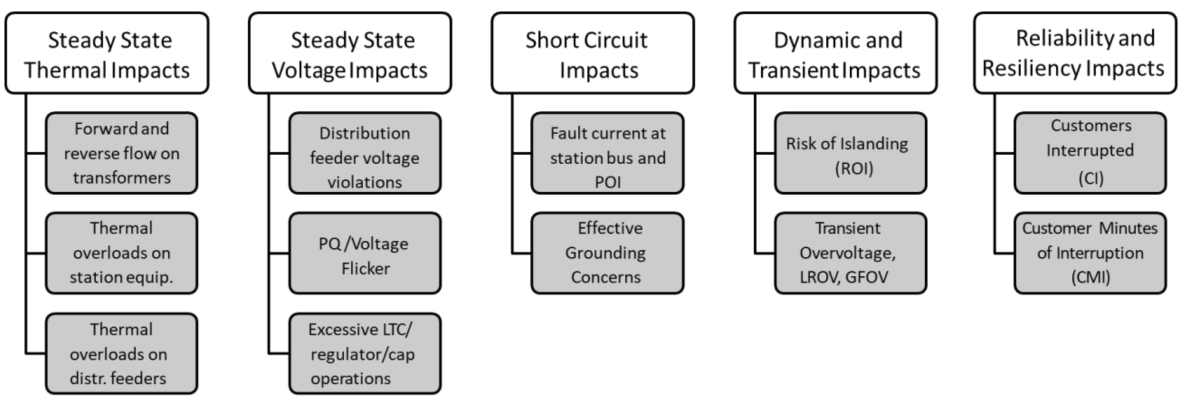


Figure 3-3: Methodologies Used for Distribution Performance Evaluation

3.2. Bulk Substation Capacity Planning – Tools, Processes, Standards, and Criteria

3.2.1. 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 an efficient, reliable, and safe EPS.
2. Performing interconnection studies to enable safe, reliable operation of DER on the Company's EPS.

The guides and standards relevant to these two (2) 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 DSPG is foundational for developing major capacity projects essential for meeting the State's future electrical demand. A list of major capacity projects needed within the 10-year planning horizon was submitted in the Company's most recent Least Cost Integrated Resource Plan docket, DE 20-121.

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 (2) 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.

Summer and Winter Equipment Ratings: It should be noted that all bulk electric system components, transmission, substation, and distribution have calculated Summer and Winter ratings. In the case of transmission and bulk substation equipment, both sets of ratings are provided to ISO-NE through power flow base case models and the associated rating databases in compliance with ISO-NE Operating Procedure #16, and the applicable Winter ratings are already used for system operations.

As noted in Section 4.0, the Company's most current 10-year forecast issued Q1-2023 does not yet include an electric heating component, as the forecast range does not yet show transition to a winter peaking system. If the Company foresees a transition from a summer peaking system to a winter peaking system, the Company can transition to using the power system equipment winter ratings for the purpose of distribution system long-term planning.

Eversource Non-Wires Alternative (NWA) Framework: The Company has 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. As part of the Company's planning guidelines in the DSPG, when evaluating distribution system improvements, engineers must consider the use of non-wires solutions as an option to defer or avoid distribution system investments, where suitable.

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 DER seeking to safely and reliably interconnect to the Company's 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:[21] This is a resource under the Customer Care section of the Eversource 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): The Institute of Electrical and Electronics Engineers (IEEE) standard 1547 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 the NH PUC Rule 900, "Net Metering for Customer-Owned Renewable Energy Generation Resources of 1,000 Kilowatts or Less", Parts 906 and 907.

[21] For additional details, refer to: der-information-technical-requirements-2023.

Reliability Planning Standards: On the transmission system, the North American Electric Reliability Corporation (NERC) develops and enforces reliability standards, annually assesses seasonal and long-term reliability, and monitors the bulk power system. On the distribution side, in most jurisdictions, and especially within the State of New Hampshire, reliability targets are set by the State, and the EDCs develop the plans and programs needed to achieve the specified level of reliability. There are also Northeast Power Coordinating Council (NPCC) reliability standards and ISO-NE Planning Procedures that are requirements governing review and evaluation of modifications to the transmission system.

It is important to note that reliability criteria as applicable to the bulk electric system are deterministic, not probabilistic, across the electric power industry. Distribution planning standards are also deterministic by mandate and represent specific targets and criteria that must be met irrespective of its associated probability, as part of the Company's obligation to serve.

Nonetheless, the Company understands that many events that impact reliability are indeed stochastic in nature, and therefore, the Company incorporates probabilistic load forecasts, adoption propensity modeling, and predictive analysis into its decision-making process to determine the least cost, yet effective, solution to improve reliability. In this way, the decision to improve reliability or address reliability deficiencies is based on deterministic criteria including customer impacts and the State's targets. The scope of the solution includes economic justification, but this is separate and distinct from using economic justification to determine whether to improve reliability.

3.2.2. Planning Process

Effective planning accounts for lead time to deploy transmission and distribution (T&D) assets in developing solutions for performance requirements. In other words, we need to plan because it takes time to build capacity on the system. Table 3-1 below shows the typical amount of time required to build capacity at various levels of the T&D system. As the table shows, it can take more than ten (10) years to build transmission, and over five (5) years to place a bulk distribution substation in service. This includes time required to: perform field audits and environmental evaluation; develop engineering designs and cost estimates; procure equipment (current lead time for transformers and switchgear is over two (2) years); and obtain siting/permitting approvals.

Table 3-1: Typical Times for Placing T&D Equipment In-Service

T&D Solution	Lead Time
Transmission	10+ years
Bulk Substation	5+ years
Primary Feeder	2-4 years
Primary Lateral Line	1-3 years
Secondary Line/Service Drop	2-12 months

To meet its obligations, the Company takes a bottom-up approach to integrated planning, with an annual cyclical planning cycle illustrated in Figure 3-4.

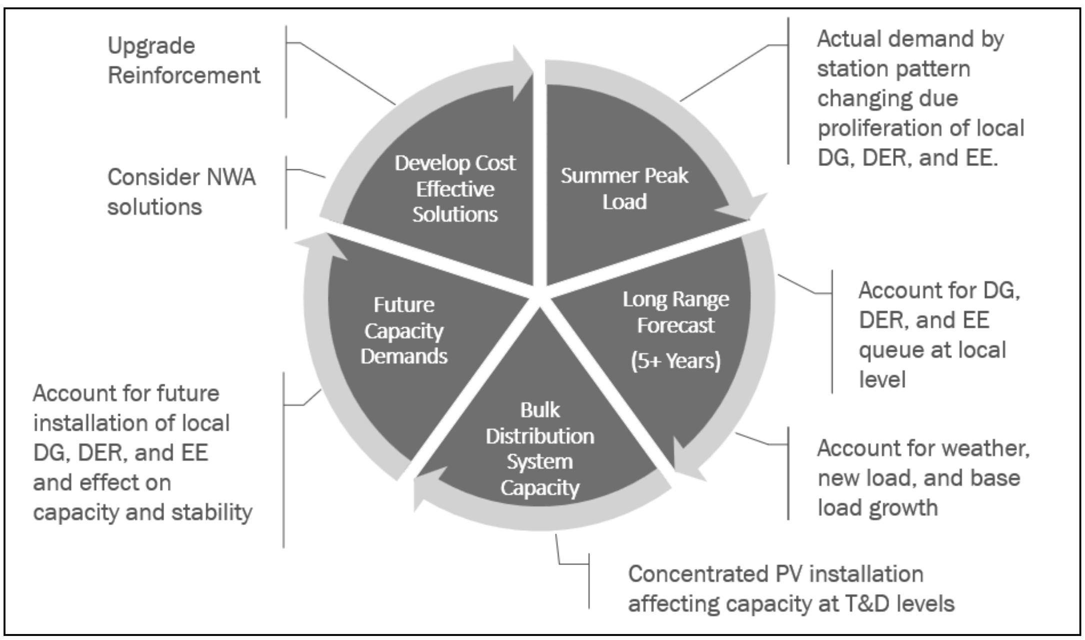


Figure 3-4: Eversource Annual Planning Cycle

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, and several adders that will impact the overall peak over and above underlying growth – considering the transition associated with electrification.[22]

The detailed assessment of electric demand focuses on the next 10 years with projected load growth through new business adoption.

As noted in Chapter 4, the near-term, or 5- and 10-year forecast, is created by the Company on an annual basis in Q1 of that year and is a direct input into the capacity planning process of the Company's System Planning Team. More specifically, the near-term forecast informs capital planning for substation projects and helps prioritize investments based on immediate need. This is necessary to ensure that any proposed solution will be suitable to meet the near-term load. It also, however, means, that the near-term forecast, unlike long-term electric demand assessment is not subject to a scenario evaluation. Substation and transmission projects are large, complex, multi-disciplinary projects that require many years of planning and engineering prior to, and during the Siting and Permitting phase. Establishing the project need with a standardized load forecasting methodology is the first step in this multi-year, and sometimes decades long, process.

In order to ensure reliable service to customers during periods of high demand, the Company utilizes a conservative approach to developing the near-term forecast based on 90/10 loading levels.[23] This is a generally accepted method used by utilities and System Operators all across the country to ensure that developed plans are suitable for addressing extreme events that could conceivably occur within the 10-year planning period. Analysis of different scenarios, especially in the early planning stages of a project, would not provide any additional actionable information to inform the project prioritization or solution design process.[24]

For example, the Company already utilizes a conservative approach to account for step loads in the near-term forecast process. The Company only includes step loads representing confirmed customer projects for which the Company has already received customer load letters, and/or the Company is reasonably certain will materialize. Based on historical records, this typically only includes step loads coming online in the first five (5) years of the forecast. Beyond that, no further step loads are typically known, confirmed, or included, and hence the step load component of the forecast remains relatively flat after five (5) years. For reference, see Section 4.3 where the

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

[23] 90/10 refers to a loading level developed in such a way that there is a 10 percent probability of exceeding the forecast due to weather conditions. The Company 90/10 forecast is based on the past 10-year weather events with the weather normalized forecast being standardized to the 90th weather percentile of the past 10 years.

[24] This is different for a long-term demand assessment beyond the 10-year horizon. There, no capital projects are initiated based on projected violations because the need is not imminent. Instead, different scenarios can help inform alternatives to infrastructure build-out, such as technology development, policy changes, rate design, and other options which can help to reduce the overall projected peak demand and capacity deficiency. Given the longer planning timeframe and lack of imminent capacity deficiency, there is sufficient time in the long-term planning horizon to observe and evaluate impacts of these approaches on the peak, while retaining sufficient response time to deploy infrastructure if such impacts do not materialize.

charts show that step loads remain almost flat after 2027. In the figure, there is no step load *growth* from 2028 to 2033 since all known step loads are expected online in the near team, from 2024 to 2027 timeframe. Step loads are the single biggest driver of growth in the 10-year period. Section 4.3 also includes charts that show the 10-year Net Forecast. Step Load accounts for 48 MW of the load increase from 2023 to 2034. Performing additional scenario analysis on how other components such as Energy Efficiency and Solar Impact affect the 10-year forecast does not negate or reduce the imminent need for the project solutions in Chapter 5.0, especially when one considers that additional step loads are sure to materialize in the last five (5) years of the forecast the closer the year approaches, i.e. step load growth will not remain flat, and may be significantly more than what could be offset with EE and solar.

Given this step load growth, and EV load and trend load growth, the projects in Chapter 5 are needed in the near-term for system capacity constraints that would result in reduced reliability, outages, and/or equipment failure if loading violations are not addressed in time. Because of the very real potential for safety, capacity, and reliability impacts, the Company cannot depend on scenarios involving policy, technology, rates, and other variables to inform decisions in this timeframe, or even wait to see which scenario will predict actual demand in the near-term. Given the significant amount of time required to engineer, procure, site, permit, and construct electrical infrastructure (as discussed above), any delay in developing timely solutions to address projected system violations in the 10-year planning horizon risks outages to customers.

To ensure that the power system is adequately planned, three (3) scenarios are typically considered when planning for large substation projects:[25]

- **Summer Peak Scenario:** Historically, in most cases, the summer peak scenario is the scenario that drives infrastructure investment. Due to high heating ventilation and air conditioning (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 and the temperature dependency. This scenario is similar to the Summer-Peak Scenario looking at high load scenarios with low, weather-adjusted DER output.

[25] 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.

- **Low Load Scenario:** The low load scenario represents the shoulder months such as April, May, and October where substantially reduced heating and cool requirements result in low load on the system and solar output can achieve 100% of nameplate power. This scenario uses a low load data and ideal solar output conditions. It is designed to identify potential for reverse flow and high voltage (overvoltage) 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 are converted to electromagnetic transients (EMT) models to allow for power systems dynamic simulations.

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

IV. **Protection reviews** 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.

In accordance with the Company's planning standards, the Company identifies the need to plan and construct new equipment, including NWAs, which expand the capacity of the system, reduce demand, and increase reliability. For example, 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 95% of the normal rating (under normal operating conditions) or the substation exceeds 90% of its Emergency Rating (under emergency conditions), the Company develops solutions to increase capacity or reduce loading.[26] This increases the electrification hosting capacity for new loads and 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.

3.2.3. Solution Development- Traditional and 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 from a capacity, reliability, and resiliency perspective, but also in relation to future electrification. Based on the system analysis results, Eversource's planning 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 applies several design concepts to resolve and mitigate issues identified in grid needs analysis. Five (5) of the more common design concepts are briefly described below:

1. **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.
2. **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.
3. **Add new equipment/capacity:** Through additional hardware, such as new circuits, or transformers at a substation, the system capacity is increased. An example is the upgrade of a single-bank substation to a standard multibank configuration[27] using standard transformer sizes[28] and increasing capacity of the substations that will maximize firm

[26] Emergency rating is defined as the substation long-term emergency capacity after the loss (single contingency) of the largest transformer (also known as Firm capacity). If additional emergency distribution transfer capability is available in addition to the firm capacity it is included as Load Carrying Capability or LCC.
[27] Substations with two (2) or more transformers connected to a Common bus provide better reliability than single transformers substations which are limited by distribution line capacity.
[28] Using standard transformer sizes is more cost-effective than step size upgrades (e.g., upgrading from 20MVA to 62MVA in a short time period).

capacity at the lowest capital cost, up to the point where transmission cost becomes the limiting factor.[29]

4. **Construct or apply NWA 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.
5. **Build a new substation**: As discussed earlier, substations are strategically located to minimize the length of distribution lines needed to serve loads. When system capacity is exhausted and there are no other practical, feasible options to reliably provide service, the best alternative might be to build a new substation, subject to siting and transmission constraints, to accommodate demand growth.

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.

3.2.4. Solution Implementation

Typically, several solutions are developed for each capacity/reliability need and the process to select a final solution involves several groups and engineering disciplines which consider and compare a range of attributes for each alternative, including cost, reliability, constructability, and environmental impact.

Once the comprehensive solution and/or solution alternatives are determined, 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 3-5.

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, 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:

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

- 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.

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 by the required date, with minimum impact on the environment, at the lowest possible cost.

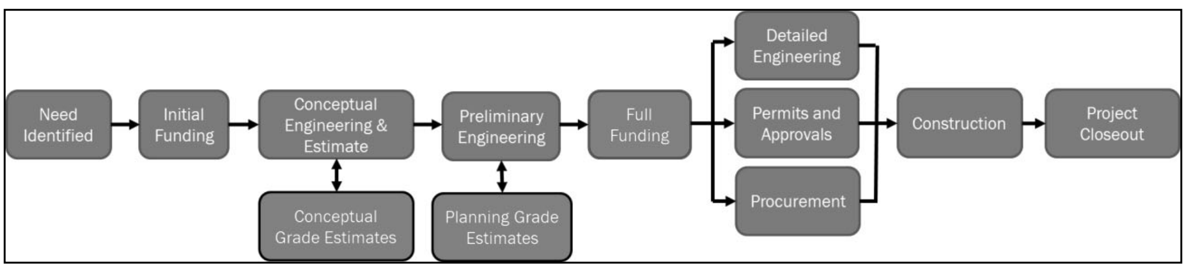


Figure 3-5: Schematic Overview of the Approval/Construction Process

3.3. Substation Asset Condition Assessments

Eversource regularly evaluates the condition of its electrical facilities, with the overarching objectives of ensuring the reliability of and minimizing risk to the electrical system, maximizing the life of assets, minimizing costs, maintaining a safe operating environment, ensuring good environmental stewardship, and conforming to regulatory requirements and standards. Allowing assets to deteriorate to the point of failure would pose safety and reliability risks.

The existing substation assets vary significantly in terms of characteristics such as age, voltage level, manufacturer, and recommended life expectancy. The environments in which the assets are located also vary widely, ranging from the coastal zone to mountainous regions, with different areas exhibiting different ambient conditions (wind, salt air exposure, etc.) that can affect asset life. As a result, whereas some facilities that are more than 40-50 years old have no asset condition issues, others demonstrate a far shorter asset life, in some cases requiring replacement within less than 20 years after installation.

Eversource has an ongoing obligation to monitor their assets and proactively implement required replacements or upgrades to maintain the reliability and integrity of the electric system. Such asset condition projects may be warranted for a variety of reasons, specific to particular circuits or substations, such as, but not limited to:

- Replace infrastructure that has reached end of life due to exposure or damage.
- Upgrade infrastructure that consists of technology that has become unreliable or is no longer supported by manufacturers.

Eversource is responsible for continually monitoring and managing their facilities and – as necessary – implementing electric asset condition investments to replace degraded assets, to address performance issues, or to meet evolving standards and regulatory requirements. There are programs designed to track and monitor the condition of its assets, to determine solutions to asset condition issues as they are identified, and to implement asset condition projects in order to cost-effectively support the continued reliability of the NH electrical system.

3.3.1. Substation Inspections

Eversource operates and maintains substations that range significantly in terms of age, design, and components, as well as overall size and surrounding environmental and land use features.

At substations, distribution assets include a range of equipment, depending on the type of station, and can include transformers, reactors, circuit breakers, bus work, relays, capacitors, switches, termination structures, control enclosures, protection and control equipment, power supply systems, physical and cyber security assets, duct bank and cable trench, etc.

Considerations in the inspection of substation components include operation and maintenance history, age or design factors, power system stress, and equipment obsolescence. The principal types of routine substation inspections include:

- **Visual Inspection** – ground-based visual inspection of substation and substation equipment.
- **Infrared Inspection** – ground-based inspection utilizing IR cameras or equipment to look for "hot spots" in substation equipment, buses, connectors, and lines.
- **Transformer Dissolved Gas Analysis** – transformer inspection utilizing oil sampling to identify contaminants in the oil that are used to indicate deterioration of internal components.
- **Transformer Offline Inspection** – detailed inspection of a transformer that requires removing the transformer from service and getting access to the internals.
- **Civil Inspection/Survey** – inspection to evaluate geotechnical conditions of the substation and site.

3.3.1.1 Additional Field Monitoring and Testing

Eversource also examines data from additional monitoring sources to comprehensively evaluate an asset's physical condition and overall performance, based on its intended function. These sources may include but are not limited to the following:

- **On-Line Monitoring**: In limited cases, monitoring devices directly connected to assets such as online transformer dissolved gas analyzers may provide daily or continuous asset testing results, which can help determine an asset's current physical condition.
- **Maintenance:** Observations of asset deterioration during routine or unplanned maintenance.
- **Equipment Testing:** Periodic testing of an asset including an asset's performance relative to expected norms.

3.3.1.2 Other Factors Considered in Asset Monitoring Analyses

In addition to the asset inspections (including field monitoring and testing), the Company also consider other factors when evaluating the overall condition of equipment. These factors include:

Equipment Obsolescence. Although certain system equipment has proven reliable over many years and has no defined asset condition issues, it may no longer be compatible with current technology on the system, may be determined by the manufacturer to be outdated, or may be identified as obsolete due to unavailability of parts or manufacturer support. The Company monitor the status of manufacturers of key asset components. Bulletins or notices also may be issued by equipment manufacturers, such as information regarding equipment obsolescence or corporate decisions to discontinue certain types of equipment. A discontinued product poses risks regarding spare part availability and manufacturer support.

Asset Failure. Eversource tracks the performance of equipment, identifying past issues, and gauge the risk and consequences of future failures, based on such historical information. Failure analyses are important in determining whether an asset problem represents an isolated situation or is indicative of a larger issue that could lead to further failures. In some cases, asset condition projects are designed to pro-actively avert future equipment failure. In other instances, some asset condition projects are required on an unplanned basis, as a result of:

- Problems that are not identified by routine inspections but cause the asset to fail in performing its intended function and require corrective action, but not on an emergency basis.
- An emergency condition that causes a disruption of power or other unplanned loss of an essential asset function, which requires immediate rectification.

3.3.2. Asset Condition Evaluation

As asset inspection data is collected, Eversource personnel review the information, along with other relevant data regarding the asset, such as maintenance history, obsolescence, etc. Data indicating problematic assets is compared to industry standards and guidelines, as well as company policies. The results of these analyses provide an initial evaluation regarding whether or not an asset condition project is required to address the identified issues. If so, further investigations are conducted, proceeding with initial scoping and budgeting for the potential asset condition project.

The condition of each individual component is the first vital piece of information required to determine the overall asset health. The asset’s condition is determined using data collected from the various asset monitoring methods, including an asset’s age and estimated useful life, physical condition, design compliance, and any obsolescence issues including replacement equipment availability. This determination may include a combination of desktop analyses of the monitoring data and further field assessments.

3.3.3. Asset Performance Evaluation

Assessing the performance and reliability of an asset or an asset model from historical maintenance, inspection and operation history helps measure how an asset has affected system reliability through unplanned outages or forced maintenance. Eversource routinely evaluates asset performance in making replacement or rehabilitation decisions. Performance factors are considered based on the asset type using current standards and guidelines and include historical data regarding maintenance and inspection, reliability, and operations.

3.3.4. Substation Considerations

The initial evaluation of substation asset conditions uses as input the results of the visual on-site inspections and monitoring, as well as the factors described in sections above. In addition, the following additional factors are often considered in substation asset condition evaluations.

3.3.4.1 Circuit breakers

Defects and deterioration identified during inspections along with known performance issues with the particular models are all considered when assessing the condition of circuit breakers. In some cases, only certain components (e.g., bushings) may in poor condition and may be replaced. In other cases, complete replacement of the breaker will be required. Offline testing can also be used to indicate potential problems with internal components.

Circuit breaker condition indicators typically including, but not limited to, asset age, environmental impacts, short circuit margin, operational integrity (operating location in substation and frequency of operation), general model obsolescence (ability to obtain trained service personnel and replacement parts), and field assessment data (maintenance notifications/issues for breaker components like bushings, mechanism, contacts, dielectric media). Operational issues also are considered in the breaker evaluation.

3.3.4.2 Transformers

Oil testing results are frequently used as an indicator of a need to conduct a further screening of a transformer. Many times, a visual inspection identifies defects and deterioration, such as leaks, corrosion, rust, connection issues, evidence of failure (burns), or other physical damage that might have occurred since the most recent formal condition assessment. The transformer loading also is evaluated and any criteria violations noted.

Transformer condition indicators typically include several parameters, such as oil quality, dissolved gas analysis, electrical testing, loading, age, information collected from inspections, and number of repair notifications.

3.3.4.3 Electromechanical Relays

Electromechanical relays are typically over 50 years old and are no longer supported by manufacturers. There is also a decreasing number of technicians who are able to repair or replace them. Moreover, modern microprocessor-based relays have numerous advantages over their electromechanical predecessors, including programmability (which reduces wiring and allows for several functions to be served by a single relay), use of modern communication-based protection methods (including fiber optics), advanced self-testing and alarming functions, storage of fault records and the ability to remotely access records and alarm information. As such, replacement and upgrade to microprocessor-based relays should be considered, especially if in coordination with another project.

A visual inspection of the relays is typically performed, checking for any corrosion, rust, signs of burning, discoloration, deterioration, dirt, dust, leaking, cracking, peeling, or pitting. Relays are also tested periodically to ensure performance in-line with predetermined testing standards.

3.3.4.4 Control Enclosures

Control enclosure projects can be driven by a variety and combination of needs. The asset condition of the control enclosure itself is a sometimes a consideration. Additional drivers such as fire safety and clean air monitoring considerations, the need to house additional or larger equipment, the need to provide improved reliability through wiring separation and other means and the need to meet regulatory obligations such as physical security protection may also determine the need for control enclosure projects.

Control enclosure asset condition indicators include a myriad of asset condition considerations varying from the physical roof, walls, and foundation, to the condition of the various types of equipment contained within the structure.

3.3.5. Asset Condition Solution Development

Based on the evaluation of the asset monitoring results and the various other factors described in this section, Eversource determines whether the identified asset condition issues warrant further examination to refine potential risks and to establish an initial scope for a potential asset condition project.

If so, Eversource proceeds with additional steps to determine the initial scope, cost, alternatives, and schedule for the project. Importantly, the decision at this point is simply whether the solution is likely to be an asset condition project.

Major decisions about the project scope, cost, and schedule are made in future steps, based on the additional detailed information compiled regarding the project and based on the criteria in those steps.

If, based on additional information developed as part on the decision-making process, it becomes clear that an asset condition project is not necessary and the identified asset condition issues can be resolved through other means such as minor maintenance, then the project may be restructured or terminated.

3.4. Distribution Feeder Capacity Planning – Tools and Processes, Standards, and Criteria

Distribution Engineering plans and expands the capacity of distribution circuits but does not prepare load forecasts for every circuit. Actual demand on the circuits is highly dependent on the addition or removal of spot loads (also referred to as incremental step loads). Regional field engineers use their local circuit knowledge and historical peak load data collected from equipment on the circuits to identify those circuits where load growth is a concern and conduct analyses as needed based on those projections. Distribution Engineering works with local municipalities to identify high growth areas of either residential or commercial load to ensure sufficient capacity is provided in the future.

In its analysis of the bulk distribution system, Distribution System Planning reviews 34.5 kV feeder loading based on historical load data, bulk substation forecasts, and the spot load information provided by Distribution Engineering. Feeders originate at the substation and are the backbone of either one or multiple circuits.

All circuits are modeled in Synergi Electric, where load is allocated and calculated on the circuit using GIS (geographical information system), OMNI (metering), SCADA and other data sources to provide Eversource with the most accurate Distribution model. The Eversource modeling team develops and maintains models of these circuits.

Using the circuit models, the following are considered during the planning process:

1. Design criteria limits conductor, recloser, and regulator loading to 100% of the normal rating. Feeders have design criteria that prompt review of upgrades when loading reaches 90% of normal rating of overhead lines and 80% of normal rating of underground cables.
2. Pole-top step transformers are of significant interest since a failure of such a device would lead to a lengthy outage. Individual assessments are made for step transformers that exceed 100% of nameplate. Peak loading of up to 120% of the nameplate is typically accepted on step transformers installed as a single unit per phase.
3. Step transformers configured with parallel 333 kVA or 500 kVA per phase are limited to 100% to account for differences in impedance and the significant number of customers served.
4. The primary voltage must be maintained between 97.5% and 105% of the nominal voltage.

New customer loads requesting service on the distribution system are typically served at circuit operating voltages of 34.5 kV or 12.47 kV. Circuits with operating voltages below 12.47 kV are limited to geographically small urban areas where individual customers do not have high peak load demands or lightly loaded rural areas serving few low customer density. Adding more customers or high demand customers (i.e., apartment buildings, condos, townhouses, multi-use developments) cause possible issues of thermal loading and voltage stability. Distribution Engineering evaluates the best solution to serve new load based on existing circuit topology and the costs of introducing higher operating voltages into the area of concern for the new load. Eversource works to not provide new services under non-standard voltages such as 3.74 kV.

Solutions for serving new load in areas where lower operating voltages exist include options for voltage conversions that factor in long-term reliability performance. These solutions range from projects that create circuit ties to provide customers an alternative source to minimize outage impacts or projects that increase existing circuit tie capacity.

3.5. Distribution Feeder Reliability Planning – Tools and Processes, Standards, and Criteria

The Company has a portfolio of reliability programs, conducted for various purposes, which can be classified under two brackets:

1. Proactive reliability programs, which are performed based on asset health considerations, safety considerations, and compliance with Company or other applicable Standards.
2. Reactive reliability programs, which are targeted to improve reliability performance as showcased through the aforementioned reliability standardized metrics like SAIDI and SAIFI.

3.5.1. Proactive Reliability Programs

These programs are based on asset health considerations, worker and public safety considerations, and compliance with Company or other applicable Standards. For example, NESC mandates pole replacements from poles whose strength is under 67%. The Company recently upgraded its standards for backbone poles to Class 1. For increased economic efficiency, the Company's approach to proactive asset-health based replacements is to create asset health models showing equipment's effective age rather than replacing assets purely based on age. In alignment with that, the Company utilizes PTX, an EPRI-developed tool, to assess bulk transformer health and prioritize asset-health based transformer replacements. Various internal asset health-based tools are currently in alpha modes of development (poles, reclosers, etc.).

3.5.2. Reactive Reliability Programs

The Company is employing a variety of commercial and in-house data analytics tools to assess reliability and plan for reactive reliability improvements with high spatial and time granularity as part of its process. First, the Company is using the IEEE methodology for reliability metrics like SAIDI and SAIFI. These metrics serve as the baseline to quantify the current status, compare historical performance across time and set targets for future performance. Through the annual IEEE benchmarking study, the Company also assesses its performance compared to other utilities.

The Company's Standards for reliability performance is to maintain top-quartile status, based on the IEEE benchmarking study. The Company's performance has indeed been commensurate with top-quartile performance both in terms of SAIDI and SAIFI since 2019. However, even maintaining reliability performance requires increased levels of spending going forward, because of the need to address challenges like electrification, climate change and aging infrastructure.

Historically, the Company has been optimizing investments in reliability improvements by creating potential projects for circuits appearing in the Worst 100 circuits based on SAIDI and SAIFI. Those circuit lists that the Company compiles are also submitted to the PUC annually. Using cost and benefit projections for each proposed project, the Company's internal project review committee gives the go ahead for projects that are most competitive based on a cost-to-benefit ratio. The Company typically utilizes the reliability functionality of Synergi for some types of reliability-enhancing projects or uses offline models to assess reliability improvements of other types of reactive reliability projects.

The Company has recently taken steps to further formalize and quantify this targeted reactive reliability work with advanced data analytics models. Specifically, the Company devised an internally developed budget optimization tool that optimizes reliability spending by answering two questions; where investments should be targeted (granular down to the individual zone/ protection device) and which type of investment is optimal in each targeted location, constrained by either a reliability goal for SAIDI or SAIFI or a budgetary constraint. At the core of this tool is a cost efficiency module that compiles, analyzes and learns from historical cost and pre- and post-investment data to create a per-unit metric of efficiency, e.g., cost per SAIDI minute saved. The tool operates at the zonal level (protection device) and uses inputs from various Company systems, including historical outage data and cost to calculate project efficiency, existing circuit and conductor types, customer counts affected, existing protection devices etc.

3.6. Distribution Resiliency Planning – Tools and Processes, Standards, and Criteria

The Company has recently introduced a resilience planning model that was developed internally. First, the model centers all-in SAIDI and all-in SAIFI as the quantification vehicle for the resilience of the system, which include events and event impacts on Major Exception Days (MEDs) as mentioned above. Second, the model targets projects to highly vulnerable zones as showcased by the Company's historical outage records during MEDs. Third, the model optimizes the type of mitigation in each targeted zone and last but not least, the model creates an optimal spending level for the overall program based on cost efficiency of each project, quantified as the ratio of delta SAIDI (historical SAIDI pre-investment and projected SAIDI post-investment) over the cost in dollars.

The purpose of Eversource's resilience methodology is two-fold:

- Support a proposed program to implement a step-change in grid resilience in New Hampshire by proactively hardening the system with cost-optimal, highly targeted projects, making use of its highly granular outage data, and
- Create a streamlined, robust, and repeatable planning process that is capable of periodically intaking new outage and circuit data to reflect recent changes.

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 based on historical outage data 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 proposed 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.

The Company's standards for all-in performance is to perform in the top 50% based on the IEEE benchmarking study. The Company's performance has been commensurate with second or third quartile performance both in terms of all-in SAIDI and all-in SAIFI since 2019, meaning that investments promoting resilience are needed, especially due to the impacts of climate change.

Below is a summary of the data model[30] that supports Eversource's resilience plan:

- Historical outage data: Eversource's methodology prioritizes the highest criticality events during MEDs as actionable events including major storm 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 where the operating device is a recloser or circuit breaker. 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.
- Eligibility criteria: The resilience plan targets zones with high criticality; either those with multiple events (chronic problems/ repeat offenders) or those with high CMI impacts per event.
- Solutions planning; The Company's resilience plan is using the following hierarchical, rules-based approach to pair resilience projects to the eligible zones. 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. 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
        - Insulated wire → Vegetation Work

  The logic of the rules is to pair the highest criticality zones with the highest impact solutions. The impact of resilience mitigation is quantified as the impact on the all-in SAIDI. Table 4 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.

[30] Section 0 provides the same view of Eversource's resilience plan with specific values.

Table 3-2: 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
Bare wire to tree wire conversion	50%	1.1
Vegetation management	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.

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.
Reconductoring to tree wire is a hardening solution for those systems that are now utilizing bare wire and are in the third tier based on the historical outage data. Their reliability benefits are lower than underground and aerial at a lower cost per mile.

Vegetation management 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 wire would not constitute a hardening upgrade.

- 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. Each project's cost efficiency is measured by the ratio of delta SAIDI (SAIDI pre-hardening minus SAIDI post-hardening) to cost. Projects are then ranked based on a decreasing cost efficiency and the program optimal spending is determined by either a target all-in SAIDI value, a budgetary constraint or a cost efficiency threshold.

4.0 Five- and Ten-Year Electric Demand Forecast

4.1. Objective and Purpose

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 be completed before a certain need is realized. Eversource's advanced forecasting and modeling capabilities allow for granular analysis, understanding load growth and projection of impacts on the local distribution system.

The Company's planning cycle begins with a forecast of load and demand growth over the ten-year planning horizon. On an annual basis, the Company projects the peak electric demand at every distribution bulk substation to assess the capability of distribution equipment to serve the load within their 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 Five- and Ten-Year Forecast is a direct input into the Company's capacity/reliability planning and project authorization process. The Five- and Ten-Year Forecast informs capital planning for substation projects, helps prioritize investments based on need and serves as a foundation for authorizing these projects. In this process, the Five- and Ten-Year Forecast is designated as a 90th percentile scenario, meaning that with 90% certainty all future loads that occur will be below the projected load. This is necessary to ensure that any proposed solution will be suitable for extremes in expected future loading. Sensitivity to large-scale roll outs of new technologies or changes in policy (e.g., building codes) take time to achieve certain market penetration and are analyzed in the long-term assessment rather than the Five- and Ten-Year Forecast, due to its near-term nature.

4.2. Five- and Ten-Year Demand 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 substation 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 4-1 below.

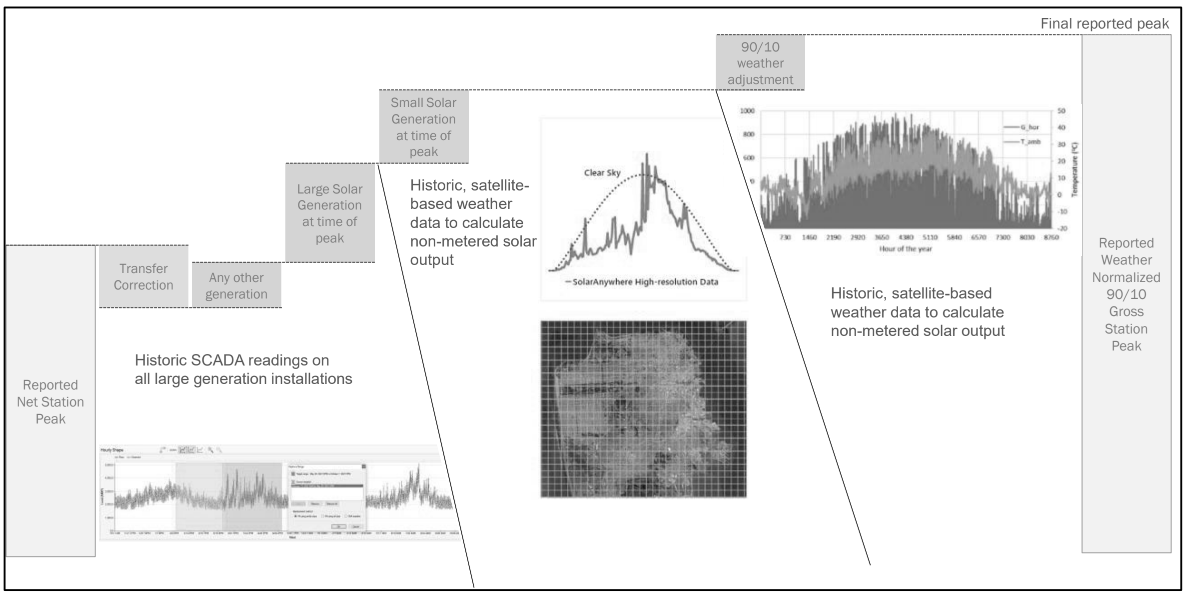


Figure 4-1: Adjustments to Reported System Peaks

These reported, weather normalized, 90/10 gross station peaks are then used, in combination with third party economic data, 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.[31] After a trend forecast is produced, the net forecast is derived by adjusting for energy efficiency (EE), solar PV, electric vehicles (EV), and large customer projects. Company-sponsored EE projections are based on the most recently approved 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. Existing and forecasted impacts from load reducing measures such as energy efficiency, distributed generation, or long-term impacts from demand response are captured in the forecast and reduce the projected net

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

load. 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 peak load history and forecast. Adjustments are made to individual substation forecasts for:

1. Specific, identified large development projects and expected changes in system configuration or operation that could not otherwise be predicted by the 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.
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 the figure below.

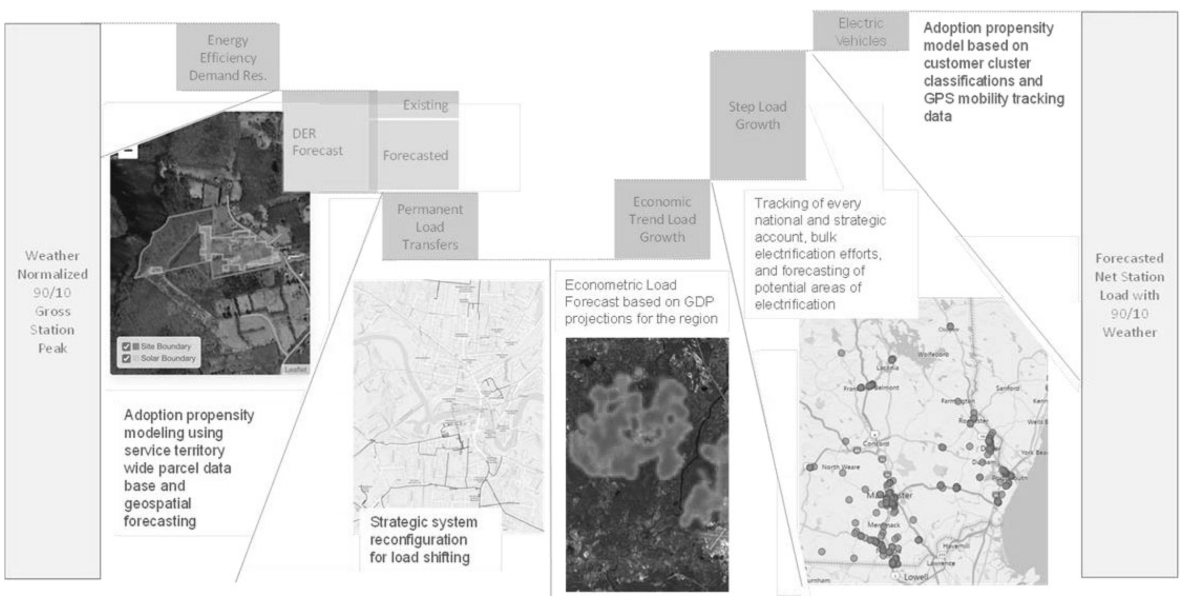


Figure 4-2: Adjustments to the Econometric Trend Load Forecast

The Company does not reconstitute loads for distributed generation units larger than 5 MW, unless those customers are on Standby Delivery Service.

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.

The Company produces both a “normal” and an “extreme”’ peak load forecast. 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.

4.2.1. 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 incentivize energy conservation measures. As an NHSaves utility program administrator, Eversource offers energy efficiency programs across all customer segments, including residential, municipalities, and 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 2024-2026 plan calls for an investment of over $158 million in energy efficiency.

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 energy efficiency 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 energy efficiency would be if a continuation of existing programs at similar funding levels yielded historically consistent impacts.

4.2.2. Solar

The solar forecast involves a two-part process: a) annual solar deployment and regional level adoption and b) generation impact on load.

Solar forecasts are translated into impacts on peak demand. With typical peaks occurring in the afternoon during summer peaks, and already significant solar on the system pushing the peak ever later in the day by offsetting mid-day load, the incremental peak reduction for every future MW of installed solar continuous to shrink.

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 and the forecasted output of solar are considered. 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. The figure 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.

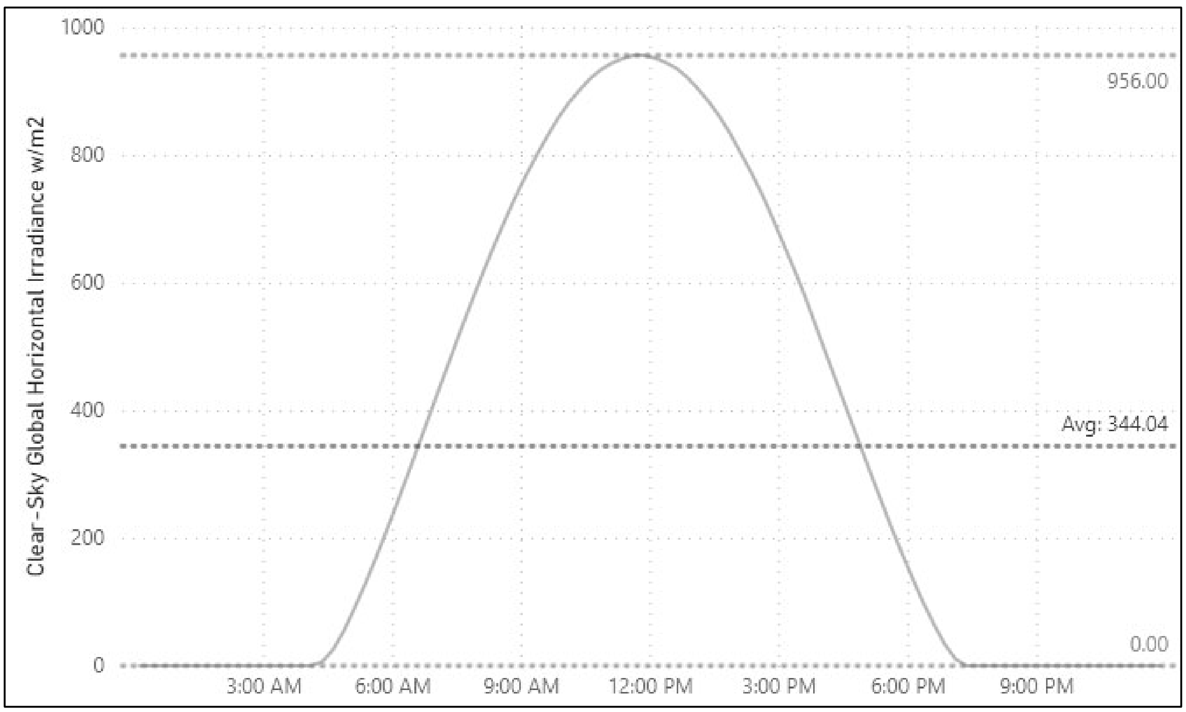


Figure 4-3: Sample 24 Hour Solar Irradiance Profile for July 1, 2022

For behind the meter solar, the Company currently does not consider any direct impacts from potentially co-sited storage due to relatively low penetration and no firm dispatch commitments from such storage. Further, the modelled peak day is based on weather conditions hot, humid, overcast which in all cases causes only partial, or no charge retained on storage systems. However, the Company is tracking the impact such systems have on the peak through its econometric modeling which correlates the station peaks over the past years with economy growth in the region. If such systems show a continuous and reliable peak reduction over multiple years that model will reduce the forecasted trend load accordingly.

4.2.2.1 Ground-Mounted Solar

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 that can:[32]

a. Assist solar developers with utility interconnection, mapping, and parcel identification for ground-mounted solar projects.
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-mounted solar development from this software platform is shown below.

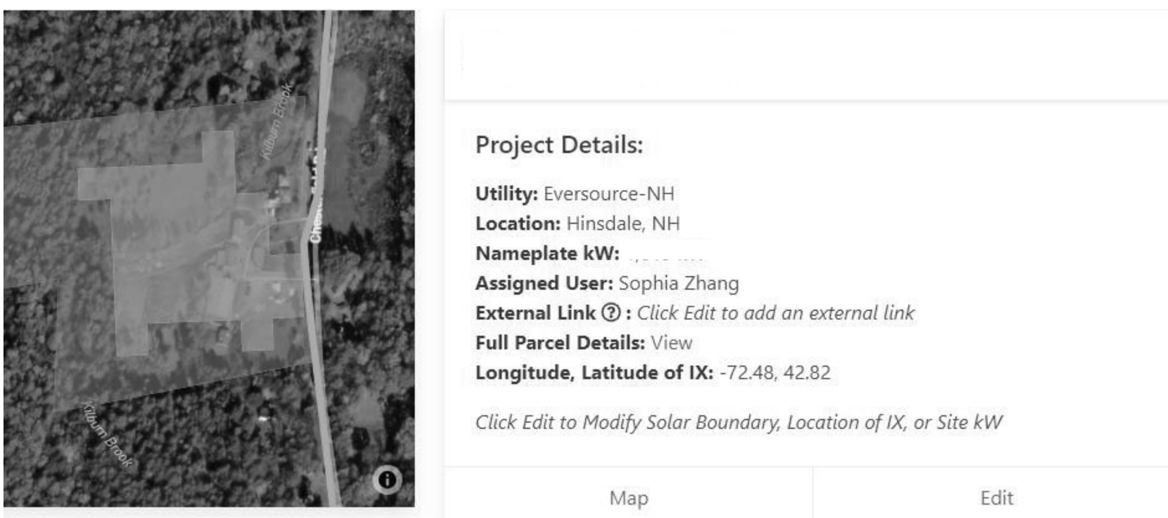


Figure 4-4: Sample of Parcel Identified as Potential Ground Mount Solar Development Project

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-mounted solar projects: cost, infrastructure capacity, and land use constraints. Land use restrictions depend heavily on regulatory guidance.

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

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

1. The annual predicted ground-mounted solar deployment in NH at the system level is applied.
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 the state, 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.

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.

4.2.2.2 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. For example, a station that peaks at 5 PM might, at best and 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. 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 territory. The key take-away from this analysis, shown in the yellow circle in Figure 4-5, 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.

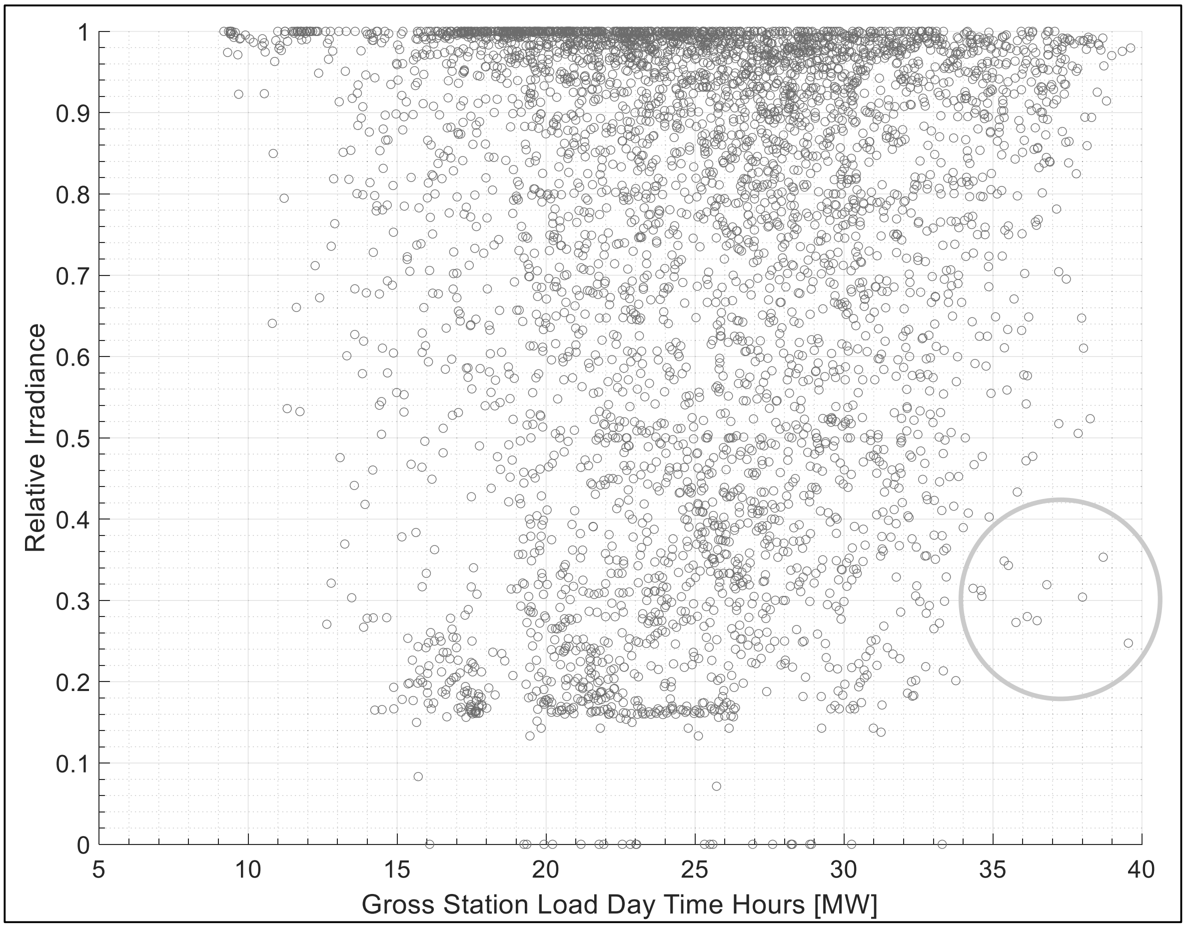


Figure 4-5: Relative Irradiance Data Sample over Gross Station Load

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 4-6 below.

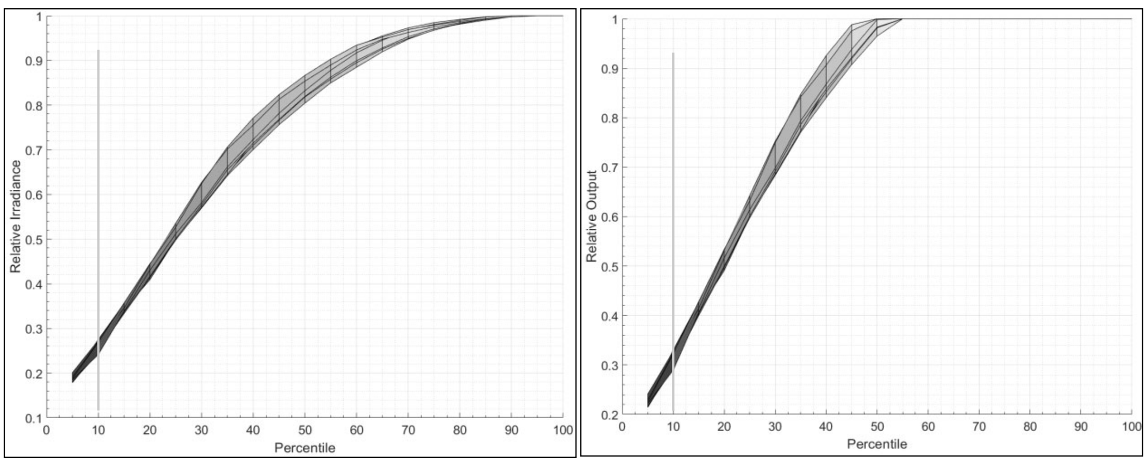


Figure 4-6: a) Historic Weather Percentiles Against Relative Irradiance and b) Impact on Relative Output with 20% Overclocking of Panels During Summer Month.

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 Figure 4-5.

Table 4-1: 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 to a winter morning peak around 2035, the expected contribution to load reduction by solar will be significantly diminished.

Figure 4-7 below shows the difference between the relative Clear-Sky Output, showing the percentage of installed $\mathrm{P_{AC}(t)}$ over two days assuming ideal weather conditions (orange trace), the relative Historic Output, showing the percentage of installed $\mathrm{P_{AC}(t)}$ based on historic irradiance data (blue trace), and the relative Planning Output, showing the percentage of installed and forecasted $\mathrm{P_{AC}(t)}$ 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.[33] 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.

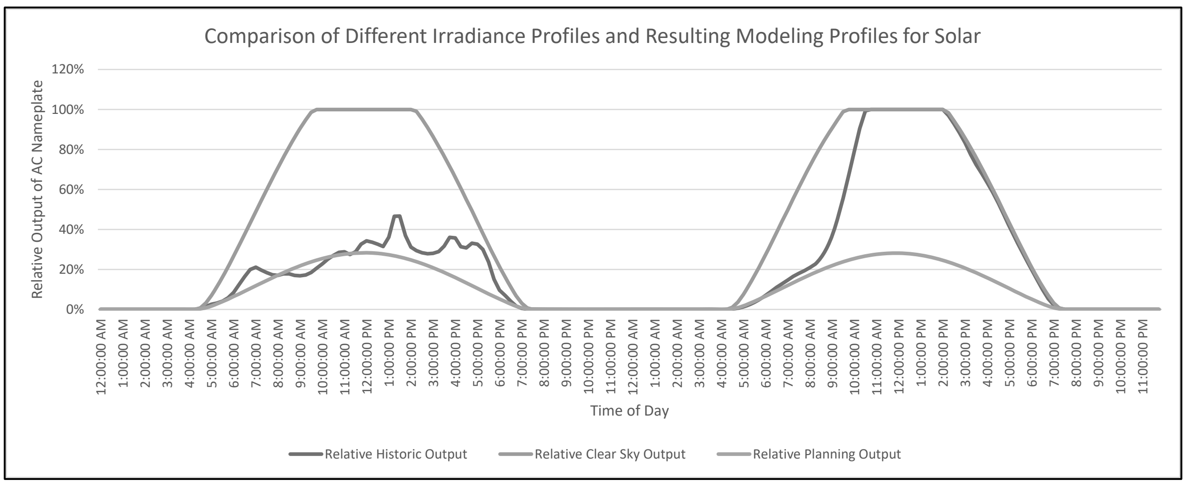


Figure 4-7: Historical June 2022 Data Showing Relative Historic, Clear-Sky, and Planning Output

The Company acknowledges that co-sited storage for the solar sites will help firm up solar output and discusses how it treats and models such impacts in the "Battery Electric Storage" sub-section below.

4.2.3. 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 500 kW or 1000 kW threshold,

[33] Overclocking have been observed at 50% for large solar projects over 500 kW.

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, to get an early indication of customer development plans. From there on, step loads undergo an evolution of certainty within the tracking system. Currently, only loads that are "Certain" are included in the forecast; taken at 100% of rated capacity (or other capacity as indicated by the customer) and expected to be online by their PTO date (usually in 2-3 years).

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. 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 sufficient 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 and the lack of a standardized system for tracking and reporting permits, this is a significant effort for the Company. As a result, it may only be feasible for select cities with significant load growth and tracking databases.

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.

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. For all incoming new construction and step loads the Company applies to the forecast are considered under the most up-to-date code at the time of construction.

4.2.4. Electric Vehicles

In the current iteration of the Company's system-level peak demand forecast, Evs 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. 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. **Existing EV penetration**: National and local market information such as EV registration, state rebate programs and state planned infrastructure investments.
b. **Future EV adoption:** The rate of adoption of EVs (as a proportion of vehicles) is based on ISO-NE transportation electrification forecasts[34].
c. **Charging profiles and locations**: Existing vehicle traffic patterns are used to estimate local potential charging demand. Analysis determines amount and type of charging infrastructure needed to sustain the system level EV penetration.

Electric vehicles are included in the ten-year demand forecast with their coincident demand at the 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 Global Positioning System (GPS) tracking data from cellular service and App providers to create travel profiles showing when, how many, and where vehicles terminate a trip. This information then allows for 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.

The steps to determine EV adoption and charging patterns are summarized as follows:

1. The annual electric vehicle adoption in NH as set out in the ISO-NE state-level projections is applied.
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

[34] ISO New England. "Final 2024 Transportation Electrification Forecast", April 2024. https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf

3. 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 as set out in the state-level projections is applied for this purpose.
4. 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 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 utilizes the results of the model to inform charge management and plan for peak load events. The Company models EV load without charge management in its base case as charge management is considered a solution.

4.2.5. Building Heating Electrification

The Company's most current ten-year forecast issued in Q1-2024 does not yet include an electric heating component, as the forecast range does not yet show transition to a winter peaking system. The Company will include a detailed heating electrification component for the forecast if the system is projected to be winter peaking.

To better assess the impact of electrification in the buildings sector, specifically for heating, the Company employs a variety of analysis methods and data sources, including:

a. **Existing electric heating penetration**: National and local market information such as company rebate programs and state planned infrastructure investments where available.
b. **Future heating adoption and conversion:** The electric heating adoption trend and assumptions in NH as set out in the ISO-NE heating electrification forecast is applied.[35]
c. **Load profiles**: heating profiles based on technology, e.g., Air Source Heat Pump (ASHP) and Ground Source Heat Pump (GSHP), and building type are used to estimate demand.

[35]ISO New England. "Final 2024 Heating Electrification Forecast", April 2024. https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf

4.2.6. Battery Electric Storage

There are two main drivers for energy storage systems (ESS) installations, the co-sited application, and the stand-alone systems. At this point, the Company is observing a significant favoring of the co-sited applications within its territory.

Large Scale Standalone and Co-sited ESS installations are treated as step loads in the ten-year forecast if their interconnection agreement allows for them to charge during peak hours. When interconnecting to the power system, ESS in the Eversource service territory, whether standalone 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 ESS site is "reserved capacity," requiring the Company to hold this capacity available at all times for the ESS operation. An ESS installation that has reserved import capacity during peak load hours will therefore be modeled as a step load at that reserved import capacity level in the forecast. An ESS installation whose schedule is such that no capacity is reserved during peak load hours does not show up in the step load forecast. This is the case for all solar and storage co-sited installations.

The Company does not make any downward corrections in the forecast for ESS applications as 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, and the clean peak standard is only a pay per performance program. Customer-owned and controlled ESS, whether standalone or co-sited, are therefore not considered to be independent resource NWA solutions. 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) ESS installations are included as part of the forecast so far as they provide historic relief to system peaks. The significant issue with BTM ESS 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 ESS installations as a firm capacity resource to displace a traditional distribution asset as the actual future performance of the ESS cannot be known.

However, to the extent that existing BTM ESS 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 4.2) which builds off the last 10 years of station peaks.

4.3. Five- and Ten-Year Electric Demand Forecast

The most recent available forecast across the system shows that step load additions, driven directly by economic development in the region, are responsible for 49 MW of the forecasted load increase from 2024-2033. System-wide, electric vehicle charging demand is the second largest load contribution on the system, with an estimated total of 12 MW of residential charging (not including large fleet charging operations or DC fast chargers). This EV charging load is spread much more equally across the Company's New Hampshire territory resulting in a lower per unit impact by region. A sizable reduction to the net load comes from projected solar installations (-40 MW) and growth in energy efficiency program savings (-83 MW) in the state. The 2024-2033 Company load forecast is displayed below by planning region.

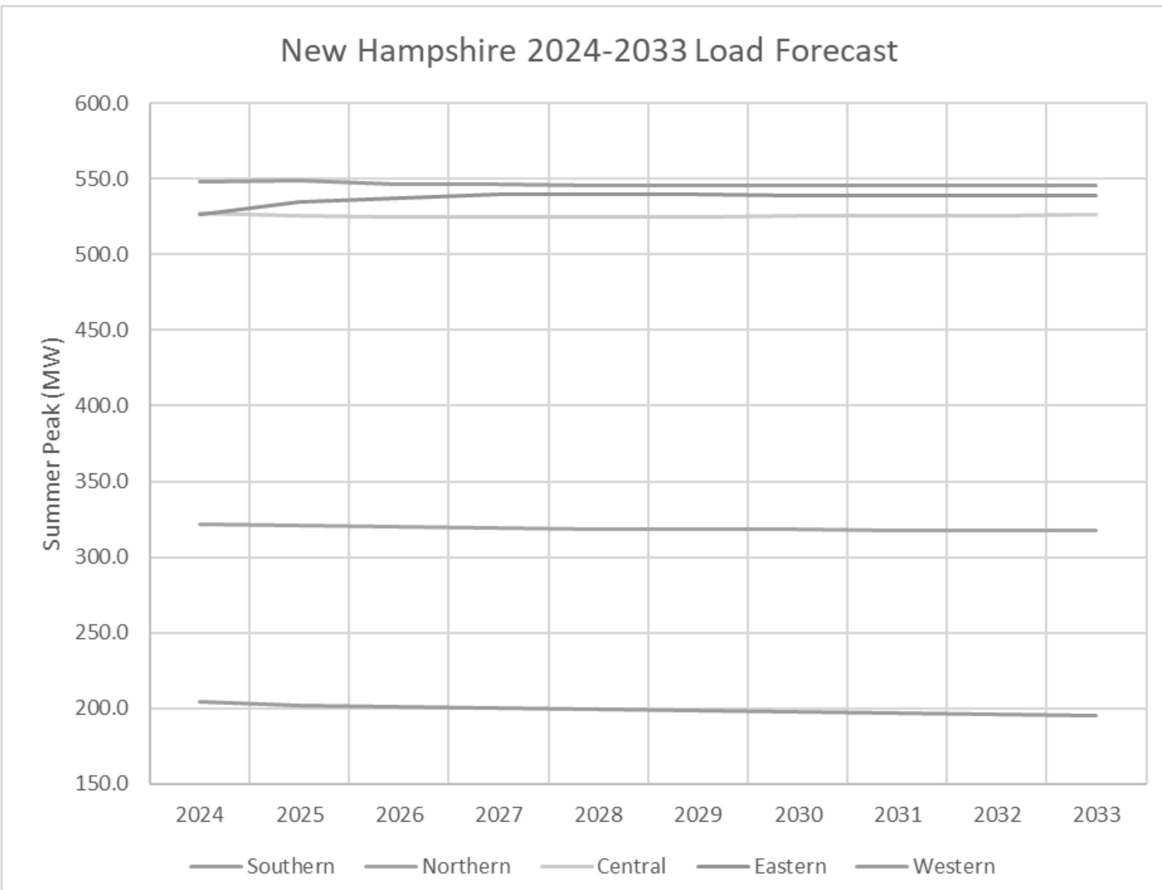


Figure 4-8 2024-2033 Coincident Summer Peak Load Forecast in New Hampshire

Step Loads represent large (> 500kW or >1 MW depending on the 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. The figure below shows the 'Certain' Step Loads in New Hampshire. These are confirmed customer loads from load letter requests and expected to come online in the next 10 years. Most confirmed projects are expected to come online in the next 3 years, 2024-2027. The largest growth area by far is in the Eastern region, followed by the Southern region. There are no anticipated step loads in Western NH at this time.

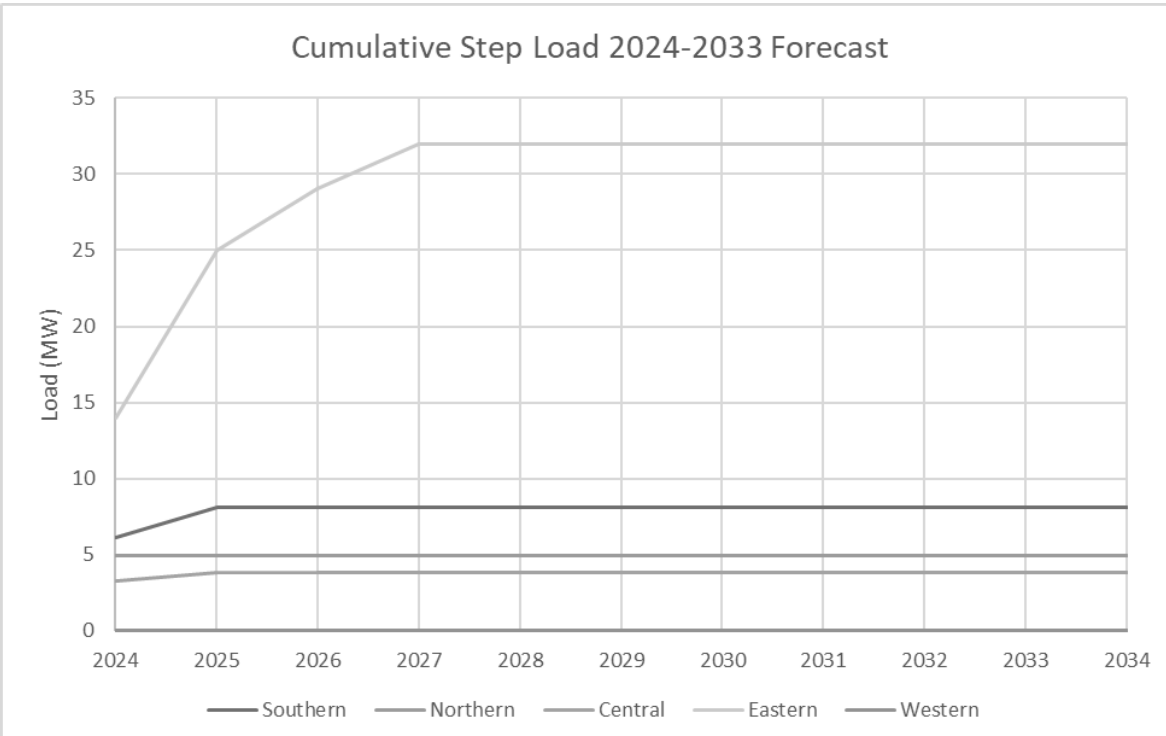


Figure 4-9 2024-2033 Large Customer Step Loads in New Hampshire

Table 4-2: Cumulative Step Loads by Region, 2024 - 2034

Region/ Year	NH	Cumulative Step Load (MW)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Southern	6.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Northern	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Central	3.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Eastern	14.0	25.0	29.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Western	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.0 Five- and Ten-Year Planning Solutions: Building for the Future

5.1. Capacity Grid Needs and Solutions Assessment (Substations and Feeders) by Region

5.1.1. Substation Capacity

Substation capacity needs and solutions are developed in accordance with the bulk distribution substation planning process described in Section 3.2. The ten-year load forecast that drives the planning process is shown by region in Section 4.3. Based on this forecast, and the ensuing system performance with respect to planning standards and criteria, system violations are identified at each bulk distribution substation, and solutions are developed to resolve each identified need.

The project needs and solutions for each substation are described in the following sections by region for the five-year investment period and the ten-year planning timeframe.

Overall, the substation capacity projects described below and the substation reliability projects, described later in Section 5.2 collectively add about 660 MW of transformer capacity, an increase of 17% over the current installed base of 3.9 GW, as shown in Figure 5-1 below.

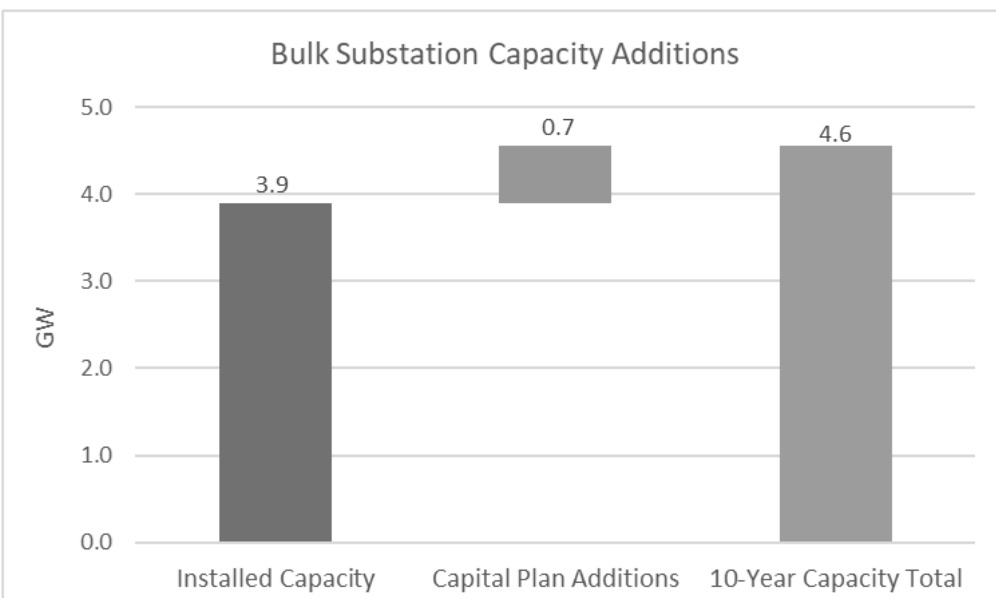


Figure 5-1: Bulk Distribution Substation Capacity Increase due to Capacity and Reliability Projects

5.1.1.1 Central Region

Based on the ten-year forecast in Section 4.3, no substation capacity projects are triggered in the Central Region at this time.

5.1.1.2 Eastern Region

Capacity Needs

Table 5-1: NH Eastern Region Projected Capacity Constraints

Substation Name and Location	Communities Supplied	2032 % of Substation Capacity	Project Solution
Cutts Street Substation *Portsmouth*	Portsmouth	**138%**	Portsmouth 12 kV Capacity Project[36]
Dover Substation *Dover*	Dover, Rochester, Rollinsford, Somersworth	98%	Dover Substation Rebuild[37]
Salmon Falls Substation *Rollinsford*	Rollinsford	97%	Salmon Falls Capacity Project

Capacity Solutions

- **Dover Substation Rebuild (Planned)**
  This project consists of:
  - A new transmission ring bus substation at Dover Substation, relocating 115 kV controls from the circa 1905 former powerhouse building into a new transmission control house.
  - Replace the existing (2) 44.8 MVA transformers at Dover Substation with Eversource standard (2) 62.5 MVA transformers.
  - Rebuild the distribution arrangement with new 34.5 kV double-bus switchgear, relocating 34.5 kV controls from the former powerhouse building into the switchgear.

- **Portsmouth 12 kV Capacity Project (Concept)**
  This project may consist of:
  - Replace Cutts Street 15W4 transformer with a single 34.5-12.47 kV 12.5 MVA transformer.

[36] The Portsmouth 12 kV Capacity Project also addresses substation reliability needs at Mill Pond Substation in addition to the capacity need identified. See Section 5.2.1.2 Eastern Region Reliability Needs.

[37] The Dover Substation Rebuild project also addresses substation reliability needs at Dover Substation in addition to the capacity need identified. See 5.2.1.2 Eastern Region Reliability Needs.

- Reconductor 200 ft of 336 ACSR with 477 ACSR Cutts Street substation to pole 32/9Y.
- Install distribution automation (DA) device at p.32/1A (near switch 4W2DX5W4) to transfer all load from 64W2 to 15W4.

The solution is to utilize a spare transformer from inventory and purchase a replacement 34.5-12.47 kV 12.5 MVA transformer to return to the contingency stock.

- **Salmon Falls Capacity Project (Concept)**
  This project may consist of:
  - Conversion of the 371X30 tap circuit on Main Street, Somersworth from 4.16 kV to 34.5 kV and extension to the 115 circuit at Old Indigo Hill Road. Reconfigure the tap circuit supply from the 371 line to the 32 line (tap circuit becomes 32X30).
  - Remove right of way portion of 13.8 kV 115 feeder from the non-bulk Somersworth Substation to Old Indigo Hill Road. Rebuild and convert the roadside portion of the 115 feeder from 13.8 kV to 34.5 kV.
  - Convert a portion of the 3148X3 circuit tap from 4.16 kV to 34.5 kV and transfer to the new 32X30 tap circuit.
  - Replace the non-bulk Salmon Falls Substation with 34.5-4.16 kV pole-top step transformers.

5.1.1.3 Northern Region

Based on the ten-year forecast in Section 4.3, no substation capacity projects are triggered in the Northern Region at this time.

5.1.1.4 Southern Region

Capacity Needs

Table 5-2: NH Southern Region Projected Capacity Constraints

Substation Name and Location	Communities Supplied	2032 % of Substation Capacity	Project Solution
South Milford Substation *Milford*	Brookline, Greenville, Hollis, Lyndeborough, Mason, Milford, Mont Vernon, New Ipswich, Temple, Wilton	110%	South Milford Capacity Project

Capacity Solutions

- **South Milford Capacity Project (Concept)**
  The selection of the preferred solution for this project is currently under review.
  The leading solution consists of:
  - Modify the distribution yard to accommodate the double bus switchgear at South Milford Substation
  - A new 34.5 kV series bus tie breaker at Amherst Substation. The load on 314X12 will be permanently transferred to the new feeder (1.5 miles, roadside), connecting South Milford Substation to Elm Street, the new SCADA device will be at Elm Street to tie with the new feeder.
  - The load on 3155 will be permanently transferred to the new feeder (3.75 miles, right of way) connecting Amherst Substation to Route 13, the new SCADA device will be on Route 13 Brookline to tie with the new feeder.

  Another solution alternative being considered consists of:
  - A 115 kV transmission ring bus at South Milford, a 115 kV, 26 MVAr capacitor bank at South Milford, new 15-mile 115 kV line between South Milford and Long Hill, and a 115 kV series bus tie breaker at Long Hill.
  - A rebuild South Milford Substation with two 62.5 MVA 115-34.5 kV transformers, 34.5 k double-bus switchgear, two 5.4 MVAr capacitor banks, one new 1.5-mile 34.5 kV feeder, load transfer from 314X12 to new South Milford feeder.

5.1.1.5 Western Region

Based on the ten-year forecast in Section 4.3, no substation capacity projects are triggered in the Western Region at this time.

5.1.2. Distribution Circuit Capacity

5.1.2.1 Central Region

The NH Central region circuit capacity has had a linear steady one to two percent growth with pockets of new commercial and residential load growth as migration from Massachusetts continues along the I-93 corridor. Current load growth in the area is outside of the downtown Manchester area, specifically with growth near the Manchester Airport and rural growth as well.

Current and future capacity projects are planned to support overloaded step transformers or overloaded distribution substation transformers (4.16 kV or 12.47 kV) when financially viable.

Eversource has close collaboration with the heavy industrial area of Manchester Airport and Hooksett with a goal to ensure adequate circuit capacity to serve both residential and commercial loads and support electrification growth.

5.1.2.2 Eastern Region

The NH Eastern region load continues to grow, with large commercial and residential growth in the area as migration from Massachusetts continues along the I-95 corridor. In the Pease area exponential commercial load growth continues as industrial load grows from the pharmaceutical industry.

Eversource needs to continue the expansion of its circuits in Portsmouth downtown area, which is in a revitalization process, with new 12 kV load. Other large towns in the Eastern region have historic 4.16 kV systems which are in the process of conversion, such as Dover where it is near completion of a conversion to 12 kV. Other towns in the region have growth where the overloaded steps require the conversion of the 4.16 kV system to 34.5 kV.

Other portions of the region encounter overloaded step transformers which requires a voltage conversion, as pockets of residential load and EV adoption continues. This conversion also addresses aging infrastructure and when possible, the conversion develops additional circuit ties.

5.1.2.3 Northern Region

The NH Northern region load profile has changed over the years, what used to be vacation campsites have become vacation houses with accompanying increases in electric demand. In addition to new residential load, the Northern region is famous for its ski resorts which are large load centers.

The Northern region has limited reactive load (motor load) support capability as it has long, radial lines and large motors at ski resorts at the end of long lines affects the voltage performance on the circuits. An example is the 34.5kV 355 circuit which is the longest radial circuit. The reliable and secure operation of the system would be severely impacted by the lack of electrical strength and low short circuit fault current when large loads (such as ski resorts) develop in the area.

The Northern region communities are served by pockets of 4.16 kV systems which are fed from overhead step transformers. These transformers are at or near overload condition and the downtown system is near its end of life, which typically a conversion is required to provide additional load serving capabilities.

5.1.2.4 Southern Region

The NH Southern region is similar to the Central region as its load has a linear steady 1% to 2% growth with pockets of new commercial and residential load growth as migration from Massachusetts continues along the I-93 corridor. Current load growth pockets are from new residential complex, retail facilities or warehouses along the Evergreen Parkway or I-93 Corridor.

Current capacity projects are due to overloaded step transformers or overloaded distribution substation transformers (4.16 kV or 12.47 kV). Where financially feasible the circuits are upgraded to higher distribution voltage which will correlate to surrounding voltages.

The PSNH team works closely with municipalities and its large customers in the area to assist in identifying and projecting future growth opportunities in the area.

5.1.2.5 Western Region

The NH Western region's load profile is similar to the Northern region as what was vacation campsites have become vacation houses especially in the Lake Sunapee area. In addition to new residential load, the Western region also has ski resorts and industrial load centers.

The Western region communities are served by pockets of 4.16 kV systems which are fed from overhead step transformers. These transformers are at or near overload condition and the downtown system is near its end of life, when typically, voltage conversion is required to provide additional load serving capability.

5.1.3. DER Integration

As discussed earlier in Section 2.4.2, DER aggregation with a high enough penetration could lead to loading of bulk and non-bulk substation transformers (during reverse flow) beyond substation transformer thermal capacity rating.

Figure 5-2 below shows the number and total capacity of DER projects installed in New Hampshire every year over the past two decades. The data shows the over the last 4-5 years, the pace of DER installations has increased exponentially as more applications are received on the system and many more small projects as well as projects 1-5 MW are being installed. In fact, the DER data in Section 2.3 shows that the majority of queued DER (over 90% in most regions) is solar, and this trend is expected to continue.

Figure 5-3 shows the current aggregate hosting capacity for DER by region. As expected, the regions with the least amount of native load, the Western and Northern regions, and correspondingly less installed capacity, have the lowest total hosting capacity. As solar growth occurs, especially in these Northern and Western regions where there is substantial developable land for solar, available hosting capacity is rapidly diminished, eventually stagnating the solar interconnection queue as developers are faced with the cost of rebuilding or expanding large bulk substations.

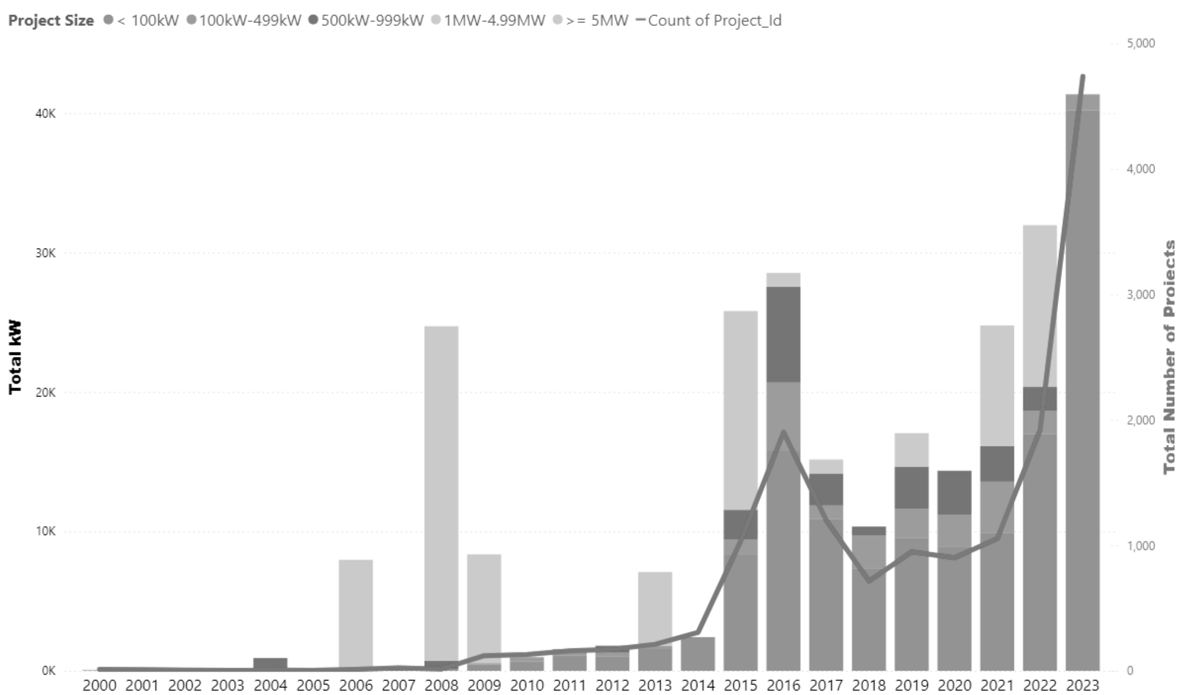


Figure 5-2 New Hampshire Online DER per Year by Project Size

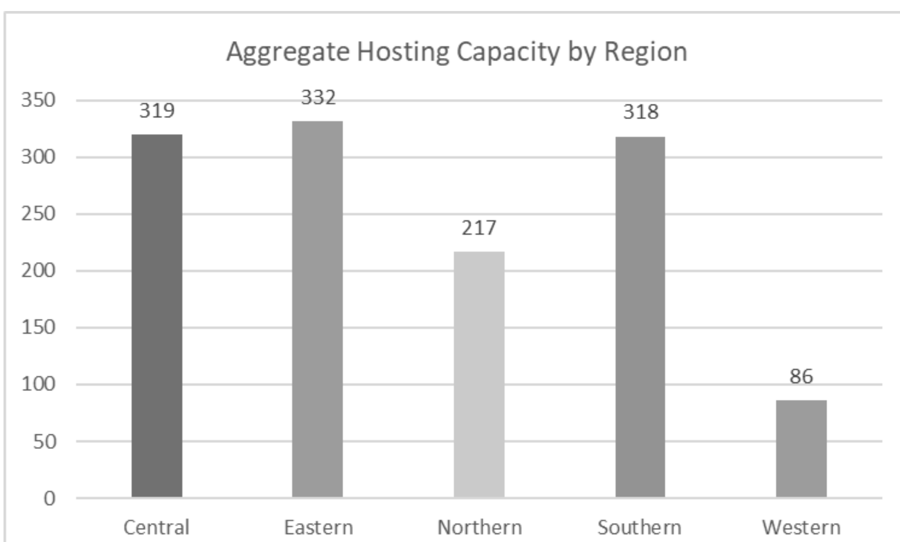


Figure 5-3: Aggregate Hosting Capacity by Region

In these areas of medium to high DER penetration, the standard approach to determining interconnection requirements and assigning costs is based on a cost causation principle; meaning that the project that triggers the need for the interconnection upgrade is responsible for paying those interconnection costs. This can result in "free rider" concerns because if a DER project interconnection triggers an upgrade to the system based on a violation identified during the interconnection study, and if that project chooses to proceed and the upgrade is put in place, that upgrade may expand system capacity at that location. This headroom would then be available to interconnect future DERs until the capacity is fully subscribed (i.e., future DERs would not be responsible for interconnection upgrade costs).

The Company's affiliates in Massachusetts and Connecticut are facing similar challenges. In those jurisdictions, the electric distribution companies are working with regulators and stakeholders to explore alternative cost allocation mechanisms. In Massachusetts, the Department of Public Utilities approved a new beneficiary-pays methodology for a set of DER-driven upgrades in Massachusetts.[38] The Company is open to working with New Hampshire stakeholders to explore similar mechanisms that could support DER development, especially in congested areas, and is in fact participating in the NH DOE Grid Modernization Advisory Group (GMAG) cost allocation subcommittee which is exploring the applicability of the Massachusetts model, as well as other mechanisms in New Hampshire. Any cost allocation mechanism must allow the Company to maintain safe, reliable service for all customers under all foreseeable operating conditions.

5.1.4. Non-Wires Alternative (NWA) Solutions

5.1.4.1 Overview

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. All technologies that directly change the loading of the system can be considered an NWA.

To clarify how the Company thinks about NWAs, a classification into five (5) different categories must be made.

[38] Alternate cost allocation methodologies were explored in the Massachusetts Department of Public Utilities Docket D.P.U. 20-75 ("*Investigation by the Department of Public Utilities on Its Own Motion into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation*"). Recently, Capital Investment Projects (CIPs) that allocated the cost of upgrades between distribution customers and DER developers in proportion to benefits accrued were approved in Massachusetts dockets D.P.U. 22-47, D.P.U. 22-52 to D.P.U. 22-55. Similar cost allocation methodologies are also being explored in Connecticut under Public Utilities Regulatory Authority docket 22-06-29RE01 ("*PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation – Non-residential Interconnection Upgrades*").

1. As part of the forecasting process, the impact of technologies such as energy efficiency (EE) and solar PV are included. As detailed in Section 4.0, 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 would be needed earlier and would be greater in scope. These "Independent Resource Addition" NWAs are considered by the Company through its forecast and the adjustments made to the forecast.
2. After the forecast is created, the Company will evaluate the need and the corresponding system plan developed by the Company (using the process discussed in Chapter 3) an and evaluate every project for NWA applicability. Suitable projects include: (1) projects which cost more than $3 million; (2) projects not related to asset age, health, or safety issues; and (3) projects with a need date more than three years out (the Company is currently evaluating lowering the $3 million threshold to $1 million as part of a settlement reached with the NH DOE during the recent concluded LCRIP proceedings). The forecasted need for a suitable project is reviewed for its possibility to be resolved by a DER. Any DER that would be part of the targeted solution mix here is utility-owned, operated, and considered a Non-Traditional Approach compared to the traditional system upgrade solutions. In all cases, this solution will defer a traditional investment, at most up to the point in time when the underlying traditional asset must be replaced. At such time, the Company will re-evaluate the Non-Traditional Approach's benefit-cost analysis (BCA).
3. Outside the capacity planning efforts of the Company, solutions, especially batteries, can be deployed as Interconnection NWAs. These solutions, such as co-sited storage may allow for a more cost-effective interconnection of DERs. These NWAs base their business case on the BCA of the developer and do not generate direct value to rate payers; therefore, they receive no value stream other than potentially avoiding paying for some system upgrades that would otherwise be needed. The EDCs do not compensate these NWAs. The Company ensures compliance with interconnection requirements using specialized hardware that set export limits (or import limits for EV chargers) at the POI.

5.1.4.2 General Best Practices

NWA projects have the highest chance of successful deployment when they address capacity issues with minimal violations that would trigger significant upgrades, including transmission projects. The Company has found that best practice for NWAs should be based on three criteria:

1. The need is not related to asset condition or safety issues.
2. The need date is at least 24 months and ideally more than 36 months out in the future.
3. The cost of the traditional wires solution is $3 million or more.

Various versions of these criteria have been used in New England 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 FTM and BTM solutions, as well as staged (year by year) roll out. If a technically viable NWA is found, it is evaluated in a BCA against the traditional solution.

To provide the best value to the rate payers, the total impact on the revenue requirements is measured for both solutions, the traditional wires solution and the potential NWA. To ensure that system constraints and issues can be addressed reliably within the Company's capital plan, it is in the customers' best 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 because at some point, the traditional asset that would require an upgrade (e.g., a substation transformer) will be so old that it must be rebuilt. Currently any upgrades to the asset only represent the incremental cost towards the rebuild, making it the most cost-effective solution.

The Company's NWA Framework compares the change in cumulative net present value of the traditional wires solution's revenue requirements with the cumulative net present value of the traditional wires solution's revenue requirements developed for the NWA. Hereby a BCA > 1 would enable the Company to proceed with the proposed NWA. Figure 5-4 below shows the Company's Solution Development Process and how screening for NWAs flows into the process.

To ensure that the NWA Framework stays up to date and always represents industry best practices, the Company engages stakeholders on a regular basis.

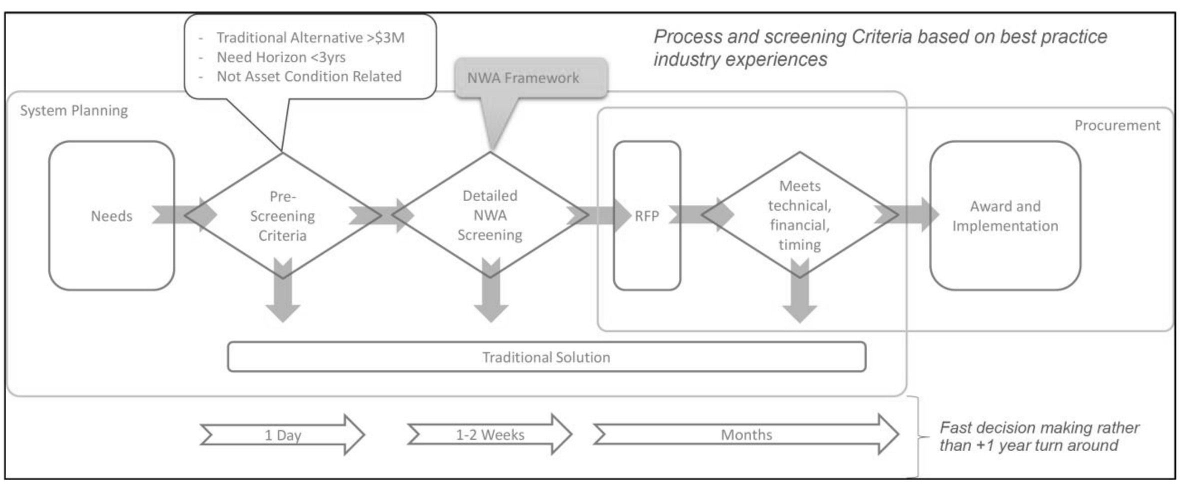


Figure 5-4: Solution Development Process for NWA

5.1.4.3 Challenges and Concerns

If deployed to defer capacity projects, NWAs are distribution assets that are part of the electric power system, and therefore subject to the same performance standards as traditional assets deployed to ensure reliability. With distribution constraints being typically very localized, NWAs may 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. With projected increase in electric demand in localized areas over the next decade, targeted NWA solutions will see increasing loads in some areas and capacity deficits which will shorten the potential timelines for deferral of the traditional solutions. This in turn reduces their overall cost-effectiveness. Capacity violations of a limited nature may present the best opportunity to implement an NWA to defer a traditional solution. As part of its distribution planning process, the Company assesses the potential of NWAs to address suitable capacity and reliability needs.

5.1.4.4 Technical Minimum Requirements

For NWAs to be considered a reliable solution, the Company's framework, and industry best practice requires full operational control, and ideally, ownership of the NWA by the EDC. NWAs which are deployed to defer capacity upgrades must have availability and performance in line with traditional assets, especially for unplanned events. This prohibits the NWA from participating in energy markets or other value-generating activity which would require dispatch of, for example a 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 to the EDC's standards 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 Public Utilities Commission (PUC). The PUC, naturally, has jurisdiction over the EDC, 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 difficult for the PUC to regulate their performance and cost.

5.2. Reliability Needs and Solutions Assessment (Substations and Feeders)

5.2.1. Substation Reliability (Single Contingency Events)

Within its service territory, the Company supplies a range of rural and urban areas which often differ in electric supply characteristics and requirements. To maintain adequate levels of reserve capacity, power quality, and reliability that meet or exceed our customer's increased expectations, Eversource designs its bulk substations to sustain any single contingency event with no load loss. The single contingency events that are planned for include loss of a bulk power transformer, loss of a distribution bus section, and bus tie breaker failure.

The bulk distribution substations in the following sections have been identified in New Hampshire as not meeting the Company's design criteria. Within the regional tables, the criteria violations are abbreviated. The description of each planning criteria violation is as follows:

- **Transformer**: For loss of a bulk substation transformer, customers should not experience a sustained outage.
- **Transformer Load**: For the single contingency event of loss of a bulk substation transformer, loading on the remaining in-service equipment and lines shall not exceed uppermost emergency ratings. Equipment with load levels allowed under emergency ratings must be reduced within certain time durations, eventually needing to be back within normal equipment and line ratings by 24-hours from the start of the event.
- **Bus Section**: For a fault on the distribution bus (the electrical connection between the bulk transformer and the distribution feeders), customers should not experience a sustained outage.
- **Bus Tie Breaker**: For failure of a circuit breaker that both protects and sectionalizes the distribution bus, customers should not experience a sustained outage.

5.2.1.1 Central Region

Reliability Needs

Table 5-3: Central Region Bulk Substations with Reliability Needs

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Bedford Substation *Bedford*	Bedford, Litchfield, Londonderry, Manchester, Merrimack	Transformer Load & Bus Tie Breaker	Manchester Area Reliability Project
Eddy Substation *Manchester*	Manchester	Transformer Load & Bus Tie Breaker	Manchester Area Reliability Project
Garvins Substation *Bow*	Allenstown, Bow, Concord, Chichester, Hooksett, Epsom, Pembroke	Bus Section	Garvins Reliability Project
Huse Road Substation *Manchester*	Londonderry, Manchester	Transformer Load & Bus Section	Manchester Area Reliability Project
Pine Hill Substation *Hooksett*	Allenstown, Auburn, Candia, Chester, Deerfield, Hooksett, Manchester, Raymond	Transformer Load, Bus Section & Bus Tie Breaker	Manchester Area Reliability Project
Rimmon Substation *Goffstown*	Amherst, Bedford, Bow, Dunbarton, Goffstown, Hooksett, Manchester, Merrimack, Milford, Mont Vernon	Transformer Load, Bus Section & Bus Tie Breaker	Manchester Area Reliability Project

Reliability Solutions

- **Garvins Reliability Project (Concept)**
  This project may consist of:
  - Addition of 34.5 kV series bus tie circuit breakers at Garvins Substation.

- **Manchester Area Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the existing 115-34.5 kV, 44.8 MVA transformers at select substations (possibly Bedford, Eddy, and Huse Road) with Eversource-standard 62.5 MVA transformers.
  - Addition of 34.5 kV series bus tie circuit breakers at select substations (likely Bedford, Eddy, Huse Road, and Rimmon).
  - Reconfiguration of the distribution system to balance load with capacity.

5.2.1.2 Eastern Region

Reliability Needs

Table 5-4: Eastern Region Bulk Substations with Reliability Needs

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Brentwood Substation *Brentwood*	Brentwood, Chester, Epping, Fremont, Nottingham, Raymond	Transformer & Bus Section	Madbury Area Project
Dover Substation *Dover*	Dover, Rochester, Rollinsford, Somersworth	Transformer Load & Bus Section	Dover Substation Rebuild
Madbury Substation *Madbury*	Barnstead, Barrington, Brentwood, Deerfield, Dover, Durham, Epping, Epsom, Lee, Madbury, Newfields, Newmarket, Northwood, Nottingham, Pittsfield, Rochester, Strafford	Transformer Load & Bus Section	Madbury Area Project
Mill Pond Substation *Portsmouth*	Portsmouth	Transformer & Bus Section	Portsmouth 12 kV Capacity Project
Portsmouth Substation *Portsmouth*	Newington, Portsmouth	Bus Tie Breaker	Portsmouth 34.5 kV Project

Reliability Solutions

- **Dover Substation Rebuild**
  This project also addresses capacity needs at Dover Substation. See *Eastern Region Substation Capacity Solutions* in Section 5.1.1.2 for project description.

- **Madbury Area Project (Concept)**
  This project may consist of:
  - Replacement of the two 115-34.5 kV 44.8 MVA transformers at Madbury Substation with Eversource-standard 62.5 MVA transformers.
  - Addition of 34.5 kV series bus tie circuit breakers at Madbury Substation.
  - Construction of a new 34.5 kV feeder towards Lee and Northwood to offload the 3137X feeder to increase contingent load carrying capacity.
  - Addition of a second 44.8 MVA transformer at Brentwood Substation.
  - Construction of a new 34.5 kV feeder from Brentwood Substation to the 3103 right of way line.

- **Portsmouth 12.47 kV Project**
  This project also addresses capacity needs at Cutts Street Substation. See *Eastern Region Substation Capacity Solutions* in Section 5.1.1.2 for project description.

- **Portsmouth 34.5 kV Project (Concept)**
  This project may consist of:
    - Construction of a new 115 kV three-breaker ring transmission substation.
    - Construction of a new 115-34.5 kV bulk substation in the area of the Pease Tradeport with one Eversource-standard 62.5 MVA transformer.
    - Construction of new 34.5 kV feeders into the Pease Tradeport area.

5.2.1.3 Northern Region

Reliability Needs

Table 5-5: Northern Region Bulk Substations with Reliability Needs

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Berlin Substation *Berlin*	Berlin, Cambridge, Dummer, Errol, Gorham, Green's Grant, Jefferson, Martin's Location, Milan, Millsfield, Pinkham's Grant, Randolph, Shelburne, Stark, Success, Wentworth's Location	Bus Section	Berlin Reliability Project
Laconia Substation *Laconia*	Belmont, Gilford, Laconia, Meredith, Sanbornton, Tilton	Transformer Load & Bus Section	Laconia Reliability Project
Oak Hill Substation *Concord*	Alton, Barnstead, Belmont, Boscawen, Canterbury, Chichester, Concord, Dunbarton, Gilmanton, Henniker, Hopkinton, Loudon, Pittsfield, Salisbury, Strafford, Warner, Weare, Webster	Bus Section & Bus Tie Breaker	Madbury Area Project
Pemigewasset Substation *New Hampton*	Alexandria, Bridgewater, Bristol, Danbury, Grafton, Hebron, Hill, Laconia, Meredith, New Hampton, Orange, Wilmont	Transformer & Bus Section	Ashland Area Reliability Project
White Lake Substation *Tamworth*	Albany, Conway, Effingham, Freedom, Madison, Ossipee, Sandwich, Tamworth, Tuftonboro, Wakefield, Waterville	Transformer, Transformer Load & Bus Section	White Lake Reliability Project

Reliability Solutions

- **Ashland Area Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the single 44.8 MVA transformer at Ashland Substation with an Eversource-standard 62.5 MVA transformer.
  - Construction of a new 34.5 kV feeder from Ashland Substation to the area of Meredith at a point along the 34.5 kV 338 feeder.
  - Reconfigure the distribution system to balance feeder loading at Ashland Substation.
  - Replacement of the two 115-34.5 kV 44.8 MVA transformers at Laconia Substation with Eversource-standard 62.5 MVA transformers. *(This item is addressed in the scope of the planned Laconia Reliability Project, i.e., scope overlap.)*
  - Reconductoring the Laconia 368 feeder with larger conductor to enable a load transfer to Laconia Substation.
  - Reconfigure the distribution system to increase contingent load carrying capacity between Ashland, Laconia and Pemigewasset Substations.

- **Berlin Reliability Project (Concept)**
  This project may consist of:
  - Addition of 34.5 kV series bus tie circuit breakers at Berlin Substation.

- **Laconia Reliability Project (Proposed)**
  This project consists of:
  - Replacement of the two 115-34.5 kV 44.8 MVA transformers at Laconia Substation with 62.5 MVA transformers.
  - Addition of 34.5 kV series bus tie circuit breakers at Laconia Substation.

- **Madbury Area Project**
  See *Eastern Region Substation Reliability Solutions* for project description.

- **White Lake Reliability Project (Proposed)**
  This project consists of:
  - Addition of 115 kV series bus tie circuit breakers at White Lake Substation.
  - Replacement of the two 115-34.5 kV 28 MVA transformers with two Eversource-standard 62.5 MVA transformers.
  - Reconstruction of the distribution substation with double-bus switchgear.

5.2.1.4 Southern Region

Reliability Needs

Table 5-6: Southern Region Bulk Substations with Reliability Needs

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Bridge Street Substation *Nashua*	Merrimack, Nashua	Transformer Load & Bus Section	Nashua Area Reliability Project
Hudson Substation *Hudson*	Hudson, Litchfield, Londonderry, Nashua, Pelham	Bus Section	Hudson Reliability Project
Lawrence Road Substation *Hudson*	Hudson, Nashua, Pelham, Windham	Transformer & Bus Section	Lawrence Road Reliability Project
Long Hill Substation *Nashua*	Nashua	Transformer Load & Bus Section	Nashua Area Reliability Project
Scobie Pond Substation *Derry*	Derry, Londonderry, Windham	Bus Section & Bus Tie Breaker	Derry 12.47 kV Reliability Project

Reliability Solutions

- **Derry 12.47 kV Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the 34.5-12.47 kV Ash Street and/or High Street non-bulk transformers with Eversource-standard 12.5 MVA transformers.
  - Reconductoring of the 12 kV distribution feeders to increase contingent load carrying capacity.

- **Hudson Reliability Project (Concept)**
  This project may consist of:
  - Addition of 34.5 kV series bus tie circuit breakers at Hudson Substation.

- **Lawrence Road Reliability Project (Concept)**
  This project may consist of:
  - Addition of a 34.5 kV transformer circuit breaker at Lawrence Road Substation.
  - Addition of 34.5 kV series bus tie circuit breakers at Lawrence Road Substation.

- **Nashua Area Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the two 115-34.5 kV 44.8 MVA transformers at Bridge Street Substation with Eversource-standard 62.5 MVA transformers.
  - Addition of 34.5 kV series bus tie circuit breakers at Bridge Street Substation.

  - Replacement of the two 115-34.5 kV 44.8 MVA transformers at Long Hill Substation with Eversource-standard 62.5 MVA transformers.
  - Addition of 34.5 kV series bus tie circuit breakers at Long Hill Substation.

5.2.1.5 Western Region

Reliability Needs

Table 5-7: Western Region Bulk Substations with Reliability Needs

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Chestnut Hill Substation *Hinsdale*	Chesterfield, Hinsdale, Richmond, Spofford, Stoddard, Swanzey, Westmoreland, Winchester	Transformer & Bus Section	Chestnut Hill Reliability Project
Jackman Substation *Hillsborough*	Antrim, Bennington, Bradford, Deering, Francestown, Greenfield, Hancock, Henniker, Hillsborough, Lyndeborough, New Boston, Peterborough, Nelson, Stoddard, Warner, Washington, Weare, Windsor	Transformer Load & Bus Section	Jackman Reliability Project
Monadnock Substation *Troy*	Fitzwilliam, Jaffrey, Marlborough, New Ipswich, Richmond, Rindge, Troy, Winchester	Transformer, Transformer Load, Bus Section & Bus Tie Breaker	Monadnock Substation Rebuild
North Road Substation *Sunapee*	Bradford, Claremont, Croydon, Enfield, Goshen, Grantham, Lempster, New London, Newbury, Newport, Springfield, Sunapee, Sutton, Unity, Warner, Wilmot	Bus Section	North Road Reliability Project

Reliability Solutions

- **Chestnut Hill Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the two 115-34.5 kV 12.5 MVA transformers at Chestnut Hill Substation with Eversource-standard 62.5 MVA transformers.
  - Addition of 34.5 kV feeder and series bus tie breakers at Chestnut Hill Substation.
- **Jackman Reliability Project (Concept)**
  This project may consist of:
  - Replacement of the single 115-34.5 kV 28 MVA transformer at Jackman Substation with an Eversource-standard 62.5 MVA transformer.
  - Addition of 34.5 kV series bus tie circuit breakers at Jackman Substation.

- **Monadnock Substation Rebuild (Planned)**
  This project will consist of:
  - Replacing the transmission facilities with a five-breaker 115 kV ring bus.
  - Replacement of the 115-34.5 kV 20 MVA and 28 MVA transformers at Monadnock Substation with two Eversource-standard 62.5 MVA transformers.
  - Rebuild the distribution arrangement with new 34.5 kV double-bus switchgear.
- **North Road Reliability Project (Concept)**
  This project may consist of:
  - Addition of 34.5 kV series bus tie circuit breakers at North Road Substation.
  - Addition of a 34.5 kV feeder circuit breaker for the 3180 line.
  - Construction of a new circuit tie with the 3180 using distribution automation.

5.2.2. Substation Asset Condition Reliability Programs

Eversource regularly evaluates the condition of its substations with the goals of maintaining the reliability of and minimizing risk to the system, maximizing the life of distribution assets, minimizing costs, and maintaining a safe operating environment. Eversource collects data on the condition of its assets through various asset inspections (including field monitoring and testing). Eversource also considers other factors when evaluating the overall condition of equipment and the need for its replacement. The factors considered include age and estimated useful life, asset physical condition equipment obsolescence, failure history, design standards, safety, and spare part availability.

Over the past several years, Eversource has developed, implemented, and enhanced key initiatives/programs as part of the Long Range Plan. The various categories in the Long Range Plan fall under general modernization (oil filled circuit breaker and recloser replacement, obsolete relay replacements, equipment monitoring, etc.), transformer reliability, automation programs such Distributed SCADA (DSCADA) Load Tap Change (LTC) controls, switchgear reliability, and substation security. Each initiative by the Long Range Capital Plan (substation) is further detailed in the next sections.

5.2.2.1 General Modernization

General Modernization (Gen Mod) addresses and replaces obsolete substation equipment that has reached the end of its useful life, e.g., breakers (non-oil), reclosers, reactors, Motor Operated Disconnects, fencing, ground grid, and annunciators. It also includes new substations, monitoring, and other equipment needed to improve substation or distribution system reliability. This initiative also addresses the removal of electrical and civil materials, and environmental remediation at retired substations. The need for equipment replacement is determined by inspections, testing, age of equipment, safety issues, operating issues, changes to standards, and spare parts availability. Currently, there are programs under way such as: battery replacements, relay replacements, roof top unit (RTU) replacements, gas monitor replacements, gas monitor and health monitor installation, station service transformer replacements, battery monitoring installations, capacitor bank switch replacements, oil circuit breaker, oil filled recloser, and ancillary equipment replacement, substation animal protection installations and substation eliminations.

Battery Replacement Program

The Program will replace the aging (20 years or older) substation batteries and chargers. The program will also evaluate the capacity required for present and planned equipment and relay installations in accordance with Eversource Substation Standards. This will assure reliable performance on the Eversource system by reducing the risk of mis-operations. Along with the replacements, the Substation Control Building HVAC systems will be evaluated for compliance with the Eversource HVAC Standards.

Relay Replacement Programs

Continuing to build upon the Company's distribution automation program, there is a need to replace substation electromechanical relays on circuit breakers with new microprocessor-based relay that provide the monitoring and control capabilities required to support the DMS' advanced network functions. The existing electromechanical relays have limitations for measuring voltage and current and providing that directly to a station RTU. This creates a blind spot for the DMS' advanced applications to make decisions. The Company plans to replace an additional 100 electromechanical line relays in 5 years.

In addition to electromechanical relay replacement programs, Eversource has several other initiatives to replace relays due to reliability, past poor performance, and manufacturer obsolescence. For instance, there is a Program to replace the obsolete Asea Brown Boveri (ABB) TPU2000R transformer differential protection relays currently existing within Eversource's NH service territories with Schweitzer Engineering Laboratories (SEL) SEL-387E current differential and voltage relays. These relay replacements are necessary due to age-related reliability concerns and manufacturer obsolescence which has resulted in key replacement components being unavailable. ABB migrated its TPU2000R relays from a Legacy to Obsolete designation according to its Last Buy Notification in January 2015.

RTU Replacement Program

SCADA systems are used throughout the transmission and distribution systems to monitor and control substation equipment. Eversource employs a fleet of RTUs to transmit status and condition data to and receive signal controls from remotely operate equipment from the SCADA system. The existing fleet of RTUs with installations dating as far back as 2001, consists of equipment from 15 different manufacturers, with more than 30 different models and configurations depending on the region, business unit (Transmission or Distribution), and type of substation communications.

The average lifespan for an RTU ranges between 10-20 years, depending upon the availability of replacement parts, manufacturer support, advances in technology, etc. Many of these systems currently in use are obsolete and no longer supported by the manufacturer. In addition, periodic hardware failures have rendered some RTUs unreliable.

The Program will investigate, evaluate solutions, and employ a standard RTU system across all service territories. Units identified for replacement will include those approaching end of life, those that have been deemed obsolete by their manufacturer, and problematic units.

Gas Monitor Replacement, Gas Monitor and Health Monitor Installation Program

There are Calisto and GE Hydran gas monitoring units on the Eversource system that are more than 20 years old and are no longer supported by their manufacturers, Morgan Schaffer and GE. These units face the risk of mis-operating and may cause a lack of oversight into equipment condition. The Gas Monitor Replacement will replace aging and failed transformer gas with new generation Calisto, Serveron, and/or equivalent units to standardize Eversource's gas monitoring protection equipment. The Gas Monitor & Health Monitor Installation program will install transformer gas monitors and health monitors on bulk distribution transformers and mobile transformers where no monitors currently exist.

The gas monitors detect the gas generation level inside transformer's main tank and provide visibility to manage the health of the transformer. Installation of gas monitors and health monitors will allow Eversource to collect and analyze transformer gas and health data thereby reducing operation and maintenance cost by alerting operating personnel of potential equipment problems. This will minimize the risk of unplanned system outages resulting from in-service failures by providing continuous monitoring of high voltage transformers and mobile transformers and will extend the life of the transformers.

Station Service Transformer Replacement Program

The Program will replace aging, poor condition, and temporary pole type substation station service transformers across the Eversource system. Proactively replacing these substation station service transformers will ensure continued reliable operation of the transmission and distribution substations.

Battery Monitoring Program

The Program will install Bulk Electric Substation (BES) Battery Monitors for all remaining batteries. North American Electric Reliability Corporation (NERC) Std. PRC-005-2 requires periodic maintenance and testing practices of BES system protection elements which includes station batteries and chargers. This includes various visual and physical inspections, as well as measurement and analysis of cell and connection resistance to identify potential problems. The latter test consists of multiple measurements of each cell (typically 60 per bank) at hundreds of stations company-wide each year. The battery monitoring program will design and install battery monitors at all remaining Transmission and Distribution BES substations to maintain compliance more efficiently with NERC Standard PRC-005-2. The installation of battery monitors will alleviate annual testing (voltage and ohmic measurements) as required by PRC-005 and provide a more comprehensive overview of system health.

Capacitor Bank Switch Replacement

The Program will replace multiple 34kV Capacitor Bank Switches based on age, condition, operating problems, and uniqueness. Some equipment has failed including cracked vacuum bottles. The Electric System Control Center (ESCC) uses the substation 34.5kV capacitor banks during high load periods to control the system losses and transmission voltage. It is important that these switches be available for energizing the substation capacitor banks on the system.

Oil Circuit Breaker, Oil Filled Recloser, and Ancillary Equipment Replacement

There are initiatives that will replace 34.5kV Oil Circuit Breakers (OCBs) as well as oil filled reclosers. There is a need to remove all circuit breakers from the system which break fault current utilizing an oil insulating medium as several are unique and old breakers that no longer have spare parts and are difficult to maintain. The program also removes breakers with Type U-Bushings from the system which have PCB oil and create an environmental risk. The overall program objective is to replace obsolete equipment to increase system reliability, increase employee safety, and reduce maintenance intervals.

Substation Animal Protection

Outages caused by animals in substations can affect the reliability to thousands of customers for a single event. This program has been initiated to provide animal protection systems throughout substations to improve reliability.

Substation Elimination

This program provides funding for the station work necessary to eliminate small, aging distribution substations that, if not eliminated, will require significant upgrades and equipment replacement to remain in service. At this time, seventeen of the substations are “Islanded” i.e., a substation where all or most of the load cannot be picked up by alternate sources in the event of a transformer failure. Rather than replacing the aging substation equipment, the preferred mitigation technique, for both the Islanded and non-Islanded substations, is to eliminate them by converting the distribution system to safely operate at a higher voltage fed from a bulk substation that is not islanded.

5.2.2.2 Transformer Reliability

Transformer Reliability addresses the proactive replacement of aging/unhealthy substation transformers. Aging substation transformers are a problem across the system. The age of a transformer is one of the most important factors in assessing asset condition. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer is approximately 40 years according to industry regulators, independent non-profits, and manufacturers. Of the 83 Bulk Substation transformers in the system, 16 are over 50 years old and 8 more are over 40 years old. Of the 103 Distribution Substation transformers, 58 of them are over 50 years old with six of them over 70 years old.

On average, one or two substation transformers fail annually across the system. As increasing numbers of these transformers reach the end of their useful life, not replacing them proactively could lead to a significant increase in the volume of failures and cause extended outages for large numbers of customers. Because of transformer age and condition, it is proposed to replace at least 4 to 5 substation transformers in NH each year.

The condition of these units is actively being monitored for degradation and replacement projects are initiated under this initiative. The multiple databases created and managed by Eversource for the purposes of cataloguing transformer asset condition, maintenance activities, and event recording, have allowed for assessment and reporting of all transformers under its ownership.

5.2.2.3 DSCADA Load Tap Changer Automation

The program will install DSCADA LTC Automation at all remaining sites currently utilizing the existing obsolete radio-controlled system for substation LTC voltage reduction. Replacement units are not available, and the system is no longer supported by the manufacturer. The program will provide the capability to remotely reduce distribution voltage by 5% during system contingencies to help stabilize the transmission system. It will provide Operations the ability to raise/lower the voltage at individual LTCs and will add increased transformer alarming.

5.2.2.4 Switchgear

This initiative 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.

5.2.2.5 Substation Security

This initiative is for enhancing security systems at key substations across the system. Substations proposed for enhanced security are critically important to the interconnection between the Transmission and Distribution systems. The Distribution funded scope of work includes the installation of a perimeter barrier, anti-vehicle protection, an intrusion detection system, and elevating distribution feeders. The scope for 2025-2029 will include access control, surveillance cameras and fence upgrades/replacement where appropriate, at key bulk substations across the system.

5.2.3. Circuit Reliability Solutions and Programs

Circuit reliability planning utilizes a tool bench of data analytics tools to evaluate the cost-effective approach in improving circuit reliability.

1. Eversource utilizes a Circuit Owner approach, thus each circuit has an engineer that is familiar with the circuit, its coordination, problematic areas, age infrastructure and fault current capabilities.
2. Eversource uses a “circuit hit list,” which has four years of circuit performance and ranks the circuits in order from worst performing. Data on the circuit allows focus on improvements and provides a data driven decision on what investments are required on the circuit.
3. Eversource evaluates the circuits not just for the Eversource customer, but also the interconnecting electrical utility, knowing that at an outage from Eversource affects a large population beyond just one metering point.
4. Eversource continues to invest in data analytic tools to evaluate circuits on a preventative basis instead of being purely reactive to outage situations; these tools evaluate momentary operations, and initiate circuit patrols.
5. Eversource utilizes the right protection equipment at the right location, with the utilization of Distribution Automation equipment to segment large customer blocks with remote communication. The goal is for each zone to have at most 500 customers. With smaller line segments, the use of TripSavers has reduced the impact of transient (temporary) faults as well as nuisance tripping.
6. One of the difficulties with long circuits on Eversource’s system, is the low available fault current. Eversource reviews protective device coordination both upstream and downstream of problematic areas to ensure dependable, secure operation to clear faults and minimize customer impact.
7. Each year, the Eversource engineering team collaboratively develops solutions that are proposed for the following year’s budget cycle for the improvement on the circuits. After

the circuit improvement project is complete, the circuit owners monitor the improvement made over the years.

With the above tools and methods, the Eversource team evaluates and develops cost-effective projects and programs to improve circuit reliability. Over the next several years, the improvement in available fault current, line segmentation, and the creation of circuit ties will support the reliability of Eversource's system both in a blue and grey sky days.

5.2.4. Co-Optimized Reliability Enhancements (Proposed Investment)

Where warranted, the Company, with authorization from the PUC, could pursue certain grid reliability enhancements through co-optimization of customer-driven investments. Periodically, the Company must make significant infrastructure investments to accommodate a large new or expanded customer load. The customer contributes to the cost of the project through a contribution in aid of construction ("CIAC") charge. However, these projects may also provide an opportunity for limited incremental investment to address broader capacity, reliability, resiliency needs that benefit the broader customer base. For example, if a new customer load requires the construction of a new substation, the Company could also reconfigure the distribution lines to serve other customers from the new substation and alleviate constraints on existing substations, thereby improving service reliability. In this manner, for limited incremental cost, the Company can take advantage of these periodic opportunities to enhance safe and reliable service and potentially future-proof investments for the benefit of the broader customer base, rather than just the customer triggering the infrastructure upgrade.

Specific investments the Company has identified as potential co-optimized reliability enhancement opportunities include:

- **The Northern Reliability loop:** Prospective redevelopment of an existing site in the North Country would require a capital project investment to upgrade existing circuits and extend service to the site. As part of the project, Eversource would take the opportunity to create a circuit tie between the two longest radial 34.5 KV circuits on I's system, the 355X and the 3525X5, which do not currently have backup sources and serve thousands of Eversource customers and New Hampshire Electric Cooperative (NHEC) members. The upgraded lines and circuit tie will improve overall reliability for the prospective new large load and other customers in the area, and spur additional economic growth in the northern area.

- **Manchester-Boston Regional Airport**: The airport is forecasting a significant load demand increase within 10 years based on electrification of customer vehicles, airport service vehicles, aircraft, and parcel delivery fleet vehicles. To serve this potential concentrated step load growth, electric infrastructure modifications and investments would be needed to replace existing transformers at several area substations, add series bus tie circuit breakers to improve reliability, and reconfigure the distribution system to balance load (see Section 5.2.1). The area-wide investment driven by the need to serve a large customer load provides improves service reliability for a wider customer base.

5.2.5. Telecommunications

Voice communications is a critical tool that the Company uses daily to maintain and operate the system. It establishes a consistent method for all field crews to be able to communicate back to the control center and crew to crew. A reliable voice radio system is critical to Eversource's business because it is a lifeline for field crews that enables the communication between teams in various locations, provides fast and secure communications, operates independently of public cellular networks, and can enable continuous communication during emergencies or black starts when other existing communication methods may not be operable. These capabilities are key to enhanced situational awareness and ultimately employee safety. In NH, there currently are 39 base radios used to create the voice radio network which connects approximately 825 mobile and portable radios. This equipment has been in service up to 30 years and is at end of life. The replacement strategy will focus on updating all of the existing equipment to enable a digital mobile radio network. The digital mobile radio network will provide several benefits over the existing analog system:

- **Improved Audio Quality:** Digital mobile radio (DMR) provides clearer and more reliable voice communication, reducing background noise and distortion that are common in analog systems.
- **Enhanced Privacy and Security:** DMR supports advanced encryption standards, making communications more secure and less susceptible to eavesdropping.
- **Better Coverage and Range**: Digital signals can be transmitted over greater distances with more consistent audio quality, extending the effective coverage area of the radio system.
- **Integrated Data Services**: DMR can transmit both voice and data, enabling features such as text messaging, GPS location tracking, and telemetry, which are not possible with analog systems.
- **Scalability and Flexibility**: DMR systems can be easily scaled to accommodate more users and can integrate with other digital networks, providing flexibility for growing organizations.
- **Enhanced Features and Functionality**: DMR radios offer advanced features such as emergency calls, priority interrupt, lone worker protection, and remote monitoring, which enhance safety and operational efficiency.

- **Interoperability**: DMR is a globally recognized standard, ensuring compatibility between equipment from different manufacturers, facilitating easier upgrades and expansions.
- **Future-Proofing:** Digital technology is continually evolving, and investing in DMR ensures compatibility with future advancements and integration with other digital communication technologies.

5.2.6. Outage Management

The Company's Outage Management System is planned to be upgraded to enable new capabilities and prepare for future use cases. The upgrade also ensures the software stays compliant, secure and compatible with the overall IT environment. The expected enhancement from the upgrade includes the following:

- Common network model creates consistent user interface for system operators and field users that will improve situational awareness
- Enhanced web viewer for ease of access and improved user performance during major events
- Improved user experience with optimized process flows to manage crews throughout the lifecycle of an event.
- Improved mobile app for damage assessment
- Enables future AMI integration which will provide a system operator the ability to remotely monitor and interact with meters to improve response to customer outages.

5.3. Resilience Needs and Solutions Assessment for Substations and Feeders (Proposed Investment)

5.3.1. Historical Outage Data-Based Distribution Resiliency Hardening Plans

New England has experienced the impacts of climate change through the increased frequency and intensity of storm events resulting in elevated all-in SAIDI. 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 Internet of Things (IoT), place the electric grid at the epicenter of various social and economic sectors. As a result, effective 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, and discusses the Company's proposed resilience investments. Section 5.3.3 outlines changes envisioned to this planning process after considering the results of the climate vulnerability study.

5.3.1.1 Historical Outage Data

The Company has investigated the outage data during major storms in the past four years (2020-2023). In order to classify major events, Eversource used the IEEE major exception threshold calculation methodology. In New Hampshire, between 2020 and 2023, approximately 804 million Customer Minutes of Interruption (CMI) are accumulated during major events.

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 where the operating device is a recloser or circuit breaker. 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. In the 2020-2023 major event data, 323 million CMI or 40% of the total major event CMI were related to reclosers and breakers' operations. The number of events and CMI during major exception days per year are shown in the following Table, while Table 5-9 further narrows this down to major storm data where the operating device is a recloser or a breaker.

Table 5-8: Historical Major Outage Data (2020-2023)

Years	Number of Major Events	Total Customer Minutes of Interruption (CMI)	Total Customers Affected (CI)
2020	4,587	188,894,752	349,487
2021	1,722	45,344,240	122,090
2022	5,325	254,302,837	403,249
2023	7,031	316,076,926	410,279
Grand Total	18,665	804,618,755	1,285,105

Table 5-9: Historical Major Outage Data, Reclosers and Breakers (2020-2023)

Row Labels	Number of Major Events	Total Customer Minutes of Interruption (CMI)	Total Customers Affected (CI)
2020	485	76,200,023	171,100
2021	187	14,882,302	57,958
2022	669	110,193,266	218,898
2023	794	121,273,918	184,355
Grand Total	2,135	322,549,509	632,311

As Table 5-8 and Table 5-9 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 recloser or breaker events 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.

5.3.1.2 Eligibility Criteria

As mentioned earlier, the resilience plan targets 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 2 or more events per zone or more than 1,000,000 average CMI per event, the resilience program focuses on 470 zones.

5.3.1.3 Solutions Planning

The Company's resilience plan is using the following hierarchical, rules-based approach to pair resilience projects to the eligible 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.

Eligible 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 and are also shown visually in the figure below.

- First tier zones -> Undergrounding
- Second tier zones -> Aerial cable
- Third tier zones
    - With bare wire -> Reconductoring to tree wire
    - Insulated wire -> Vegetation Work

The logic of the rules is to pair the highest criticality zones with the highest impact solutions. The impact of resilience mitigation is quantified as the impact on the all-in SAIDI, based on Table 3-2.

The following flowchart visualizes the rule-based approach described above.

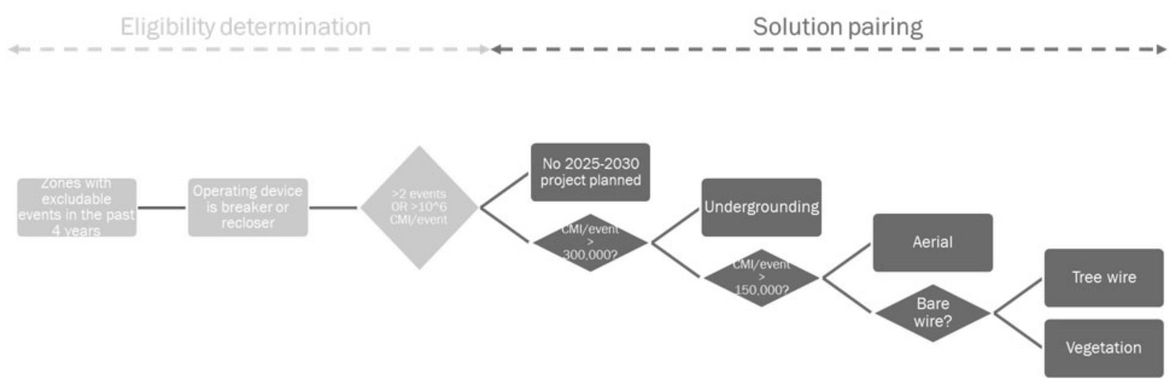


Figure 5-5: Rules-Based Approach to Solutions Planning Process

5.3.1.4 Optimal Investment Saturation Point

Applying this rule-based methodology results in a 20% reduction of all-in SAIDI with projects on 470 zones. 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 470 resilience projects are ranked based on their cost efficiency as measured by the ratio of delta SAIDI (SAIDI pre-hardening minus SAIDI post-hardening) to cost. The following figure shows the delta SAIDI per dollar on the vertical axis in descending order plotted against the running resilience program cost on the horizontal axis. Because of the way the graph was constructed, the curve can be seen to have a declining slope as the potential program cost increases.

The total cost is $1,551M for the aforementioned 20% all-in SAIDI reduction, therefore the optimal investment point is set as the point where the cost efficiency is three times higher than the cost efficiency of the entire program (SAIDI reduction divided by program cost). For this case, the cutoff point for a proposed resilience program is pegged at $150M for a 4.3% SAIDI reduction.

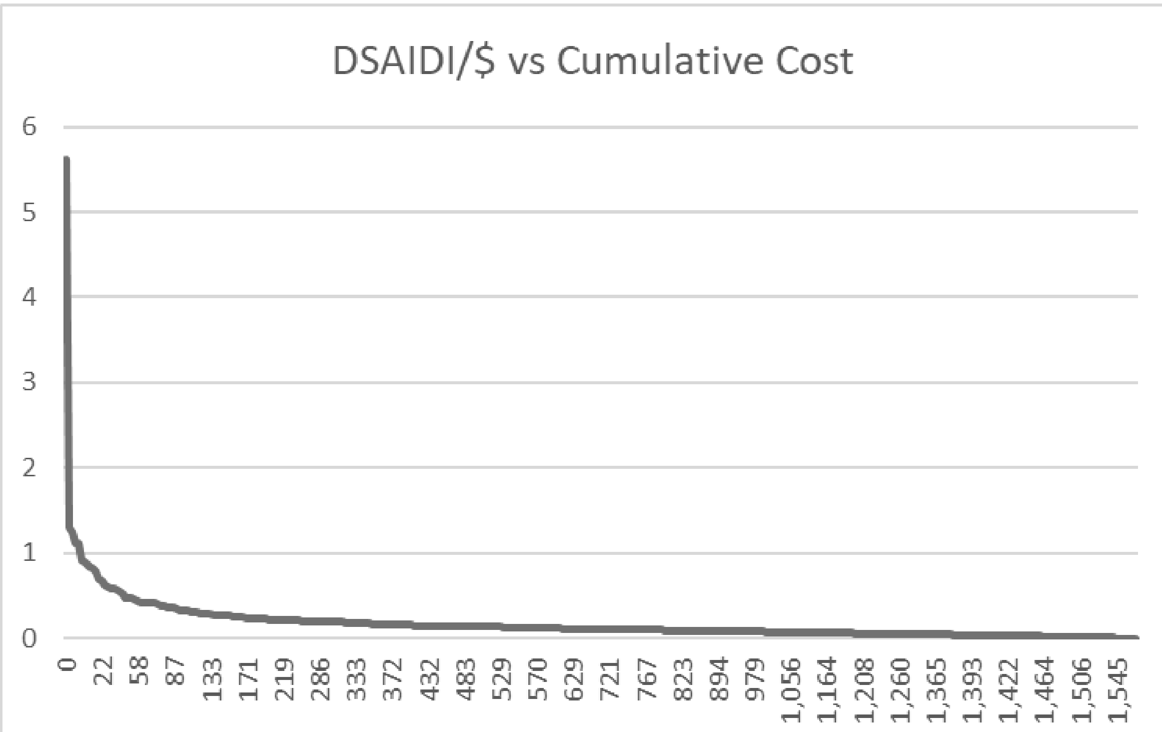


Figure 5-6. Resilience programs ranked by cost efficiency (DSAIDI/$) versus program costs.

5.3.1.5 Results of the proposed methodology

Applying this rule-based methodology results in 48 potential projects under the proposed resilience program. Since the focus was on high criticality events, the methodology is expected to result in high undergrounding percentages. Specifically, 29% of the zones or 14 zones are paired with undergrounding. Reconductoring to tree wire is paired with 25% of the zones or 12 zones and is the second most common mitigation measure proposed. Vegetation represents 23% of the projects (11 zones). Aerial cable also represents 23% of the projects (11 zones).

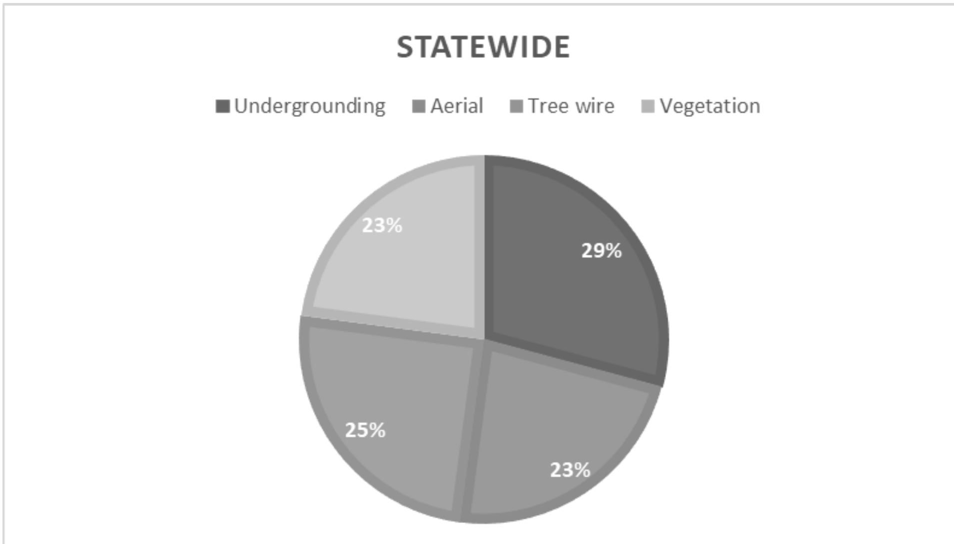


Figure 5-7. Resilience projects in plan by project type

In terms of the various planning regions, most projects are in NH Eastern (33% or 16 projects). 29% or 14 projects are in NH Northern. NH Western, NH Central and NH Southern get 7, 6 and 5 projects respectively (15%, 13% and 10% of all projects respectively).

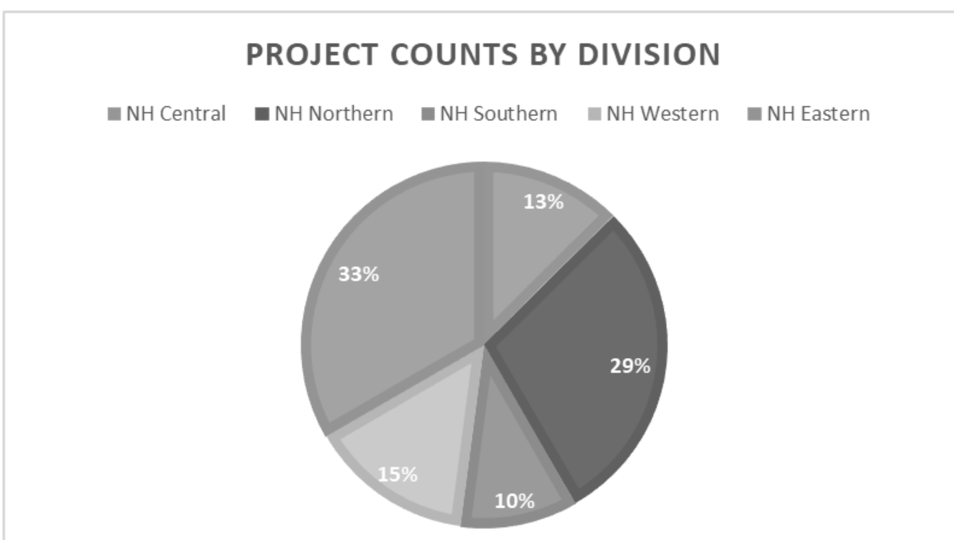


Figure 5-8. Resilience projects in plan by planning region

The results can further be broken down into specific regions. In NH Western, 72% of the zones (5 zones) are paired with undergrounding. This is because events in this region are typically high impact SAIDI-wise, due to the system being on overhead with long zones and without many ties. In other regions, undergrounding ranges from 18%-34% of the region's projects. In NH Eastern, most projects are aerial cable (44% or 7 projects).

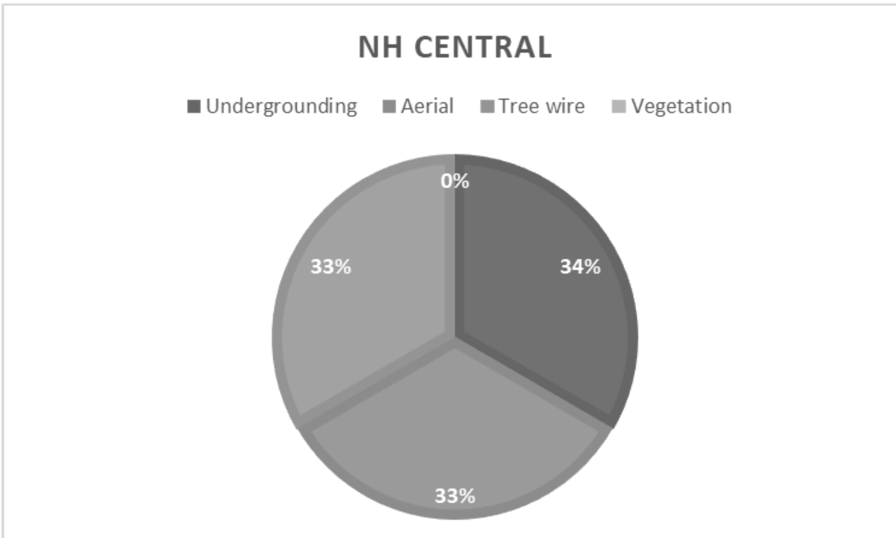


Figure 5-9. Proposed resilience projects in NH Central by project type

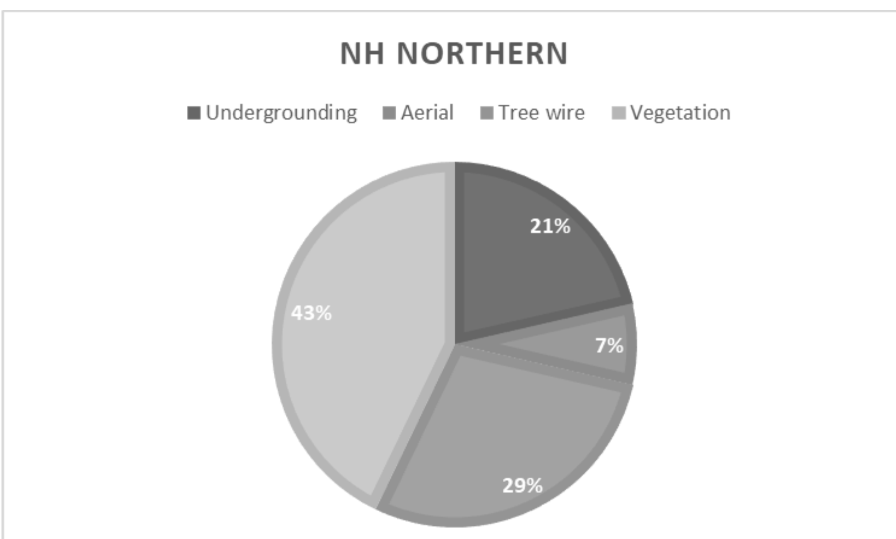


Figure 5-10. Proposed resilience projects in NH Northern by project type

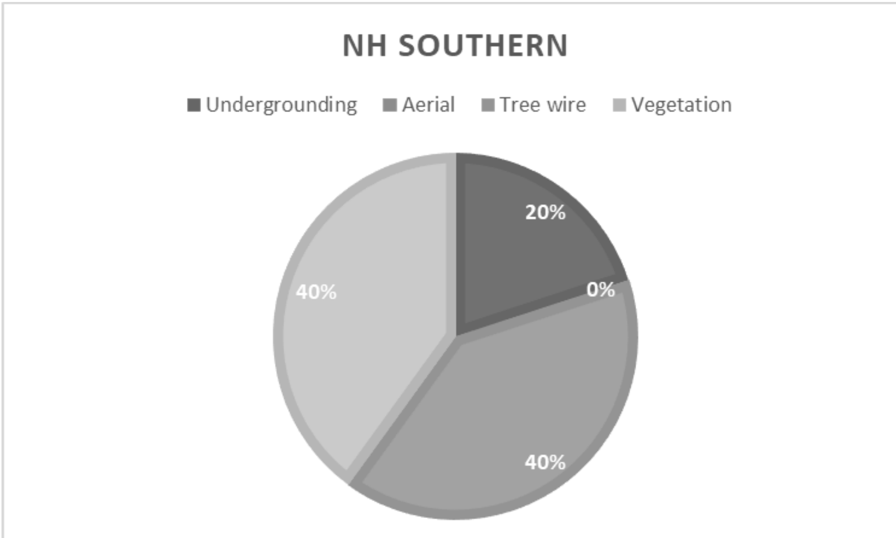


Figure 5-11. Proposed resilience projects in NH Southern by project type

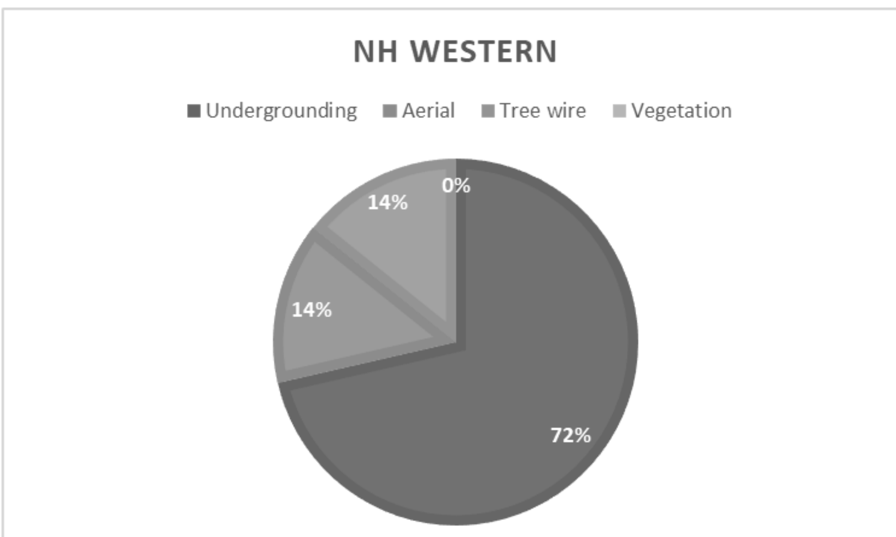


Figure 5-12. Proposed resilience projects in NH Western by project type

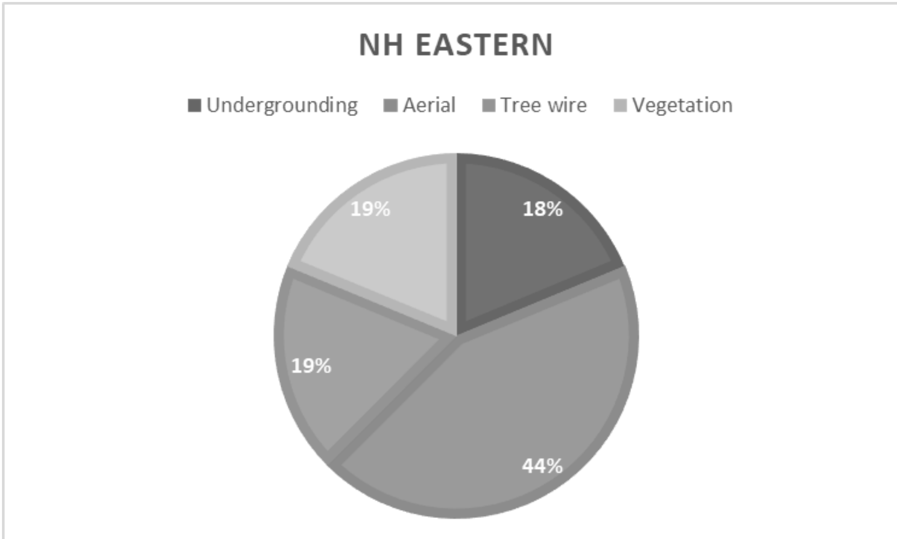


Figure 5-13. Proposed resilience projects in NH Eastern by project type

5.3.2. 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 2.3 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, 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 projected 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 projected. For example, Table 5-10 shows there are 11 different variables utilized to describe the temperature projections. The list also includes indirect effects, such as the impacts of temperature changes to demand.

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 be properly highlighted and addressed. These statistical downscaling models are refreshed periodically; the Company is the first EDC to use their latest version.

Table 5-10: 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 (2) and three (3) consecutive day heat waves with daily maximum temperature over 90th and 95th percentiles 6. Frequency of two (2) and three (3) 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 one (1) and five (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

Two climate change scenarios were used for the projections: the Shared Socioeconomic Pathways (SSP) 2-4.5 and SSP5-8.5. The former assumes that greenhouse gas (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 projections extend out to 2080 with intermediate steps for 2030, 2040 and 2050.

Projections use a common set of 23 LOCA Global Science Models across SSP2-4.5 and SSP5-8.5. For each climate science variable and each SSP scenario, the 10th, 25th, 50th, 75th and 90th percentiles are calculated. Mathematically, the 90th percentile represents the right tail of the probability distributions, where 90% of the samples have a lower value. The 90th percentile of the

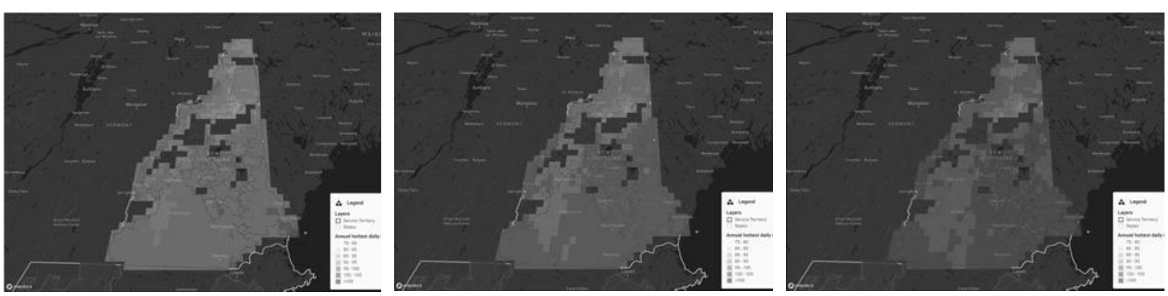
SSP5-8.5 is highlighted in the upcoming results, as it represents a worst case or a perceived ceiling of the forecast. The results also highlight the 50th percentile of SPP2-4.5, as a more middle-of-the-way scenario to contrast with that worst case. The 50th percentile represents a value that is higher 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. Because both the average and maximum temperature are projected to increase, the electric system stress during blue-sky days and associated performance will change too, creating a broader impact than just isolated occurrences and major storms.

The following tri-fold figures are organized as follows: from left to right the historically observed values of the variable, the projected value under SSP2-4.5 50th percentile for 2050 and the projected value under SPP5-8.5 90th percentile for 2050.

The two-fold figures show the evolution of a variable's projection 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.

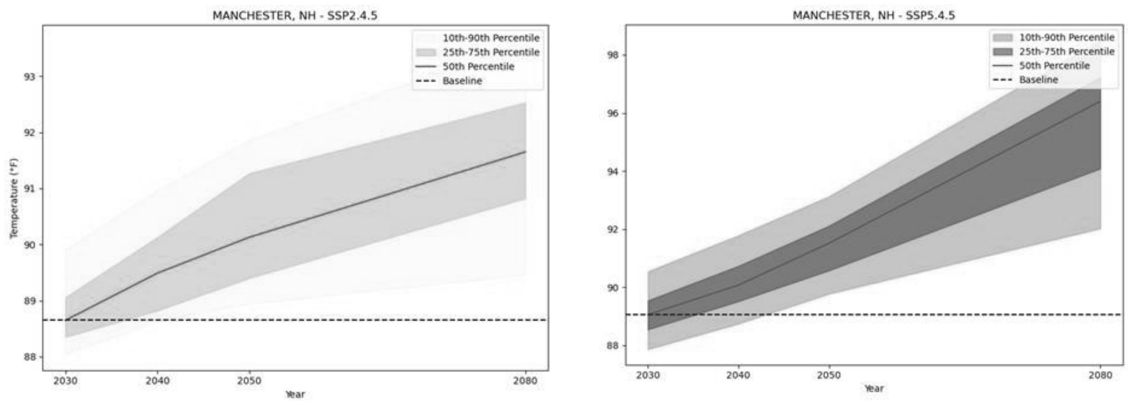
Figure 5-14 shows the projected annual hottest daily temperature. Both SSP2-4.5 50th percentile and SPP5-8.5 90th percentile show the warming impacts in all the Company's NH territory. Under SSP2-4.5 50th percentile, the southeast part of the State is warmer, while the Northern and most of the west part of the State have a similar annual hottest daily temperature to today's values. Under SPP5-8.5 90th percentile it is only the northernmost part of the State that retains a similar annual hottest daily temperature to today's values, while all other areas warm up significantly.



Historical Observed *SSP2-4.5 50th percentile* *SPP5-8.5 90th percentile*

Figure 5-14: Projected Annual Hottest Daily Temperature in 2050

A view across time of the same variable (annual hottest daily temperature) for Manchester is provided in Figure 5-15 below. Both emission scenarios show a progressive increase of the annual hottest daily temperature from 2030 to 2080. Under SSP2-4.5, the projected range of the annual hottest daily temperature in Manchester in 2050 is approximately 2F, while under SSP5-8.5 the projected range of the annual hottest daily temperature in Manchester in 2050 is close to 3F (using 25th-75th percentiles for both scenarios). Under SSP5-85 the range of projected annual hottest daily temperature for 2080 further expands.

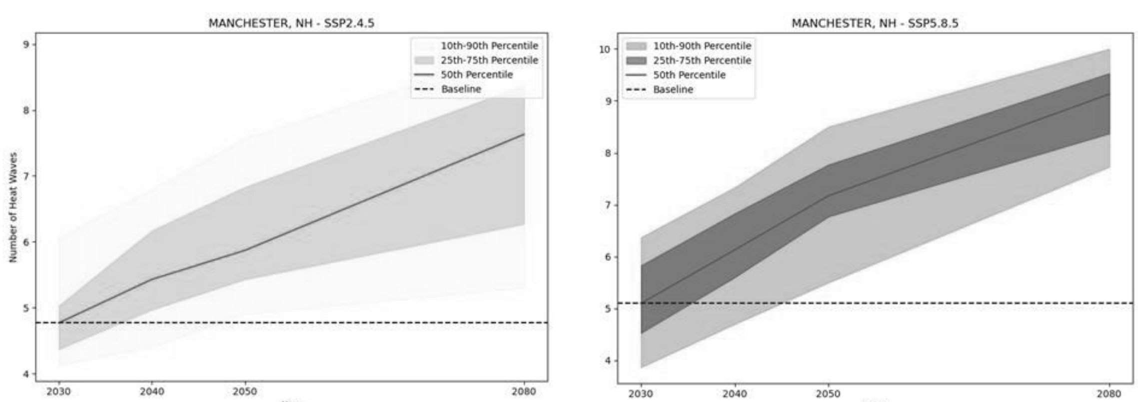


SSP2-4.5 SSP5-8.5

Figure 5-15: Projected Annual Hottest Daily Temperature for Manchester, 2030-2080

The warming climate can also be quantified through the duration and frequency of heat waves; the study projects about five to seven heat waves annually by 2050, while the current baseline is 2.2 heat waves annually. Heat waves are expected to be 7.8 to 27.7 days long in 2050, a substantial increase from today's baselines of 4.4 to 7-day long heatwaves.

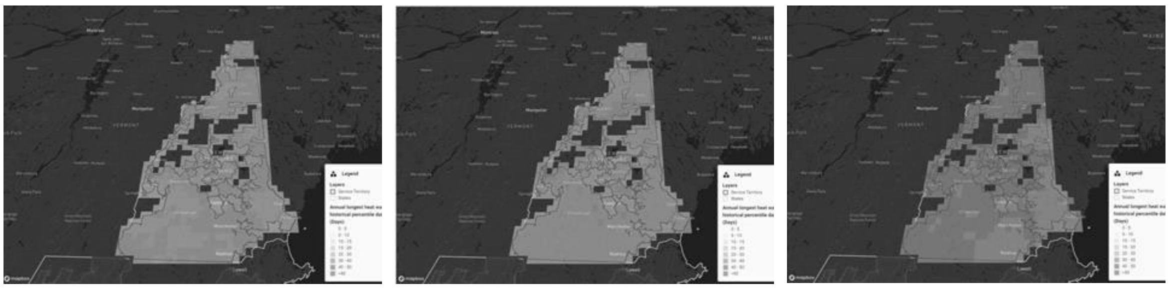
A view across time of the number of the three-day heat waves for Manchester is provided in the Figure 5-16 below. Both emission scenarios show a progressive increase of the number of three-day heat waves from 2030 to 2080. Under SSP2-4.5, the 50th percentile of the number of the three-day heat waves for Manchester in 2050 is projected to be seven three-day long heat waves, while under SSP5-8.5 the 90th percentile of the three-day heat waves for Manchester in 2050 is projected to be nine three-day long heat waves.



SSP2-4.5 SSP5-8.5

Figure 5-16: Projected Three Day Heat Waves in Boston 2030-2080

Figure 5-17 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 projected to be 7.8-15.0 days in 2050, about the current 4.4-7 days. Under SPP5-8.5 90th percentile, the annual longest heat wave is projected to be 11.7-27.7 days in 2050, potentially almost quadrupling the current 4.4-7 days.

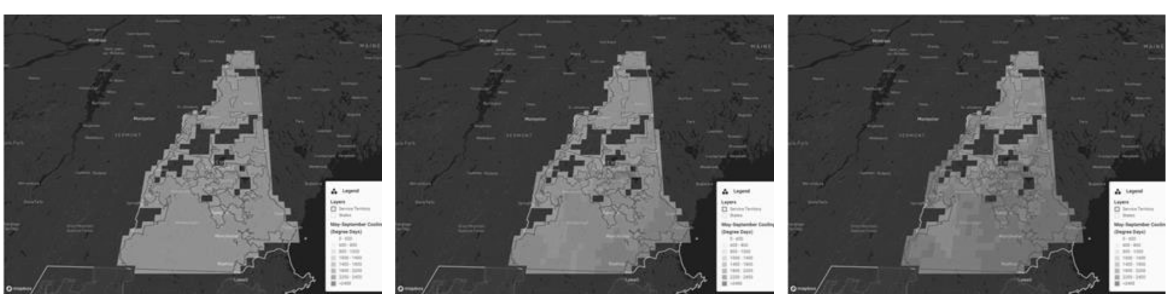


Historical Observed *SSP2-4.5 50th percentile* *SPP5-8.5 90th percentile*

Figure 5-17: Projected Annual Heat Waves in 2050

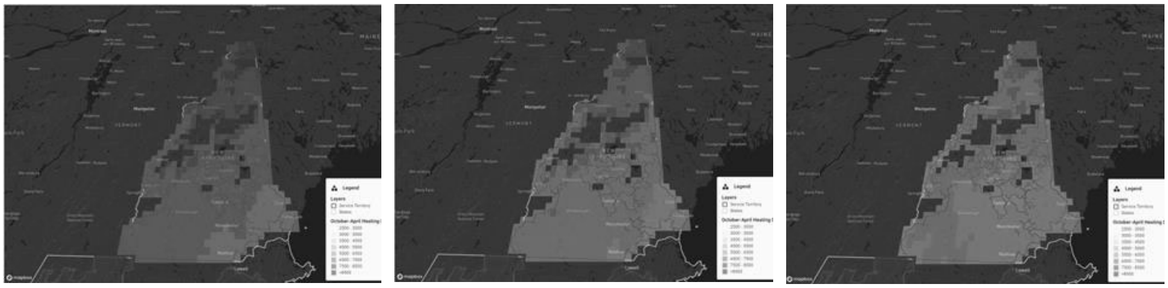
Summer demand will increase significantly as a result; May to September cooling degree days is expected to increase to 84-1681 annually by 2050, potentially doubling from today's baseline of 14-926 cooling degree days. Figure 5-18 and Figure 5-19 below show the cooling degree days in the summer months (May-September) and the heating degree days from October to April. Heating degree days subside statewide in both scenarios. The Company notes that while a warming climate is projected, 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.

Cooling days increase particularly in the southeast part of the State, in alignment with the projections of annual hottest temperature shown above.



Historical Observed *SSP2-4.5 50th percentile* *SPP5-8.5 90th percentile*

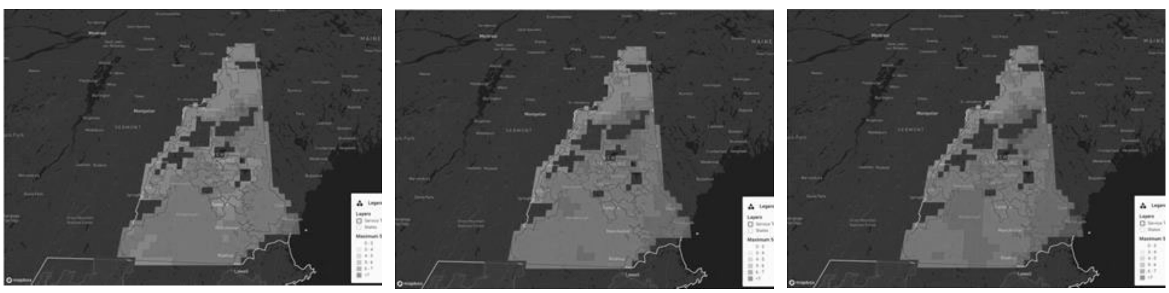
Figure 5-18: Projected Cooling Days from May to September in 2050



Historical Observed *SSP2-4.5 50th percentile* *SPP5-8.5 90th percentile*

Figure 5-19: Projected Heating Degree Days from October to April in 2050

Figure 5-20 shows the 5-day maximum precipitation. Both the results of SSP2-4.5 50th percentile and of SPP5-8.5 90th percentile reveal progressively worsening and spreading high precipitation around Portsmouth and west of Manchester and Concord.



Historical Observed *SSP2-4.5 50th percentile* *SPP5-8.5 90th percentile*

Figure 5-20: Projected Five-Day Maximum Precipitation in 2050

5.3.3. Framework to Address Climate Vulnerability Risks Through Resilience Plans

As Sections 3.6 and 5.3.1 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 ambient temperature will be the highest (daily maximum or average) or where the highest precipitation or wind speed is expected). This granular identification of peaks of climate hazards' projections are going to form the new targets of additional resilience work. The timing of the need (i.e., the pace of climate change) will also be factored in when optimizing mitigations.

The critical, final step in the Company's proposed resilience plan is to pair projected grid vulnerabilities due to progressing climate change with the optimal resilience project based on the type of climate science variable that mostly affects the area. Table 5-11 is a causation and effect table that qualitatively associates climate hazards to grid asset types and to potential mitigations.

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 association table below (Table 5-11) will be used to optimize mitigations for each climate hazard and asset pair. Since these projects are long-term (multi-year), the Company is expecting a need to prioritize projects across time and inform a multi-year resilience plan.

Table 5-11: Associations of Climate Hazards with Affected Asset Types and Potential Mitigations.

Climate Hazard	Affected Asset Type	Potential Mitigations
Extreme Temperature	Transformers Conductors (Underground and overhead)	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 & pad-mounted equipment	Substation elevation Water proofing, trenching
Drought	All OH equipment (secondary impact through drought impacts to vegetation)	Enhanced tree trimming and tree removals. Higher class poles Reconductoring Undergrounding
Sea Level Rise	Substations All UG & pad-mounted equipment	Substation elevation Water proofing, trenching
Storm Surge	All OH equipment Substations All UG & pad-mounted equipment	Enhanced tree trimming and tree removals Higher class poles Reconductoring Undergrounding Substation elevation Water proofing, trenching

The Company expects that climate change impacts will create a new normal that could drive change in Planning, Standards and Operations across its entire territory. The Company is therefore laying the groundwork for the potential re-evaluation of existing Standards, Operating Practices and System Planning as discussed above. As explained below, the Company expects a potential new or accelerated need to replace overhead and underground conductors, station, and network transformers with higher ampacity ratings 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) to accommodate increased energy demand for cooling loads. System Planning models may require edits to produce cost-efficient solutions with multi-scenario probabilistic inputs such as those returned by the climate change vulnerability study.

Overhead conductors

Air temperature is a key parameter when sizing and loading overhead conductors. Overhead conductor rating is dependent on conductor material type, ambient air temperature and average wind speed. 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. Figure 5-14 and Figure 5-15 above show 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 updates and associated replacements/ upgrades is expected.

Increased wind speeds can result in cable faults due to trees encroached in or in close proximity to the overhead wires, but on the other hand, lower wind speeds offer less cooling and increase the potential need to derate the operating loads on the wires during high ambient temperatures.

Underground conductors

Underground cable ampacities are dependent on soil resistivity, earth ambient temperature and the installation configuration (depth, number circuits/duct bank). Soil ambient temperature relates to air ambient temperature, while soil resistivity may also depend on drought or precipitation conditions. Since the cable jacket is rated to a maximum temperature limit (75^{o}C/90^{o}C/100^{o}C), the underground cables might require derating to limit the temperature rise beyond the cable rating.

Transformers

The ratings for station transformers and network transformers depend on ambient temperature, amongst other factors. In the Company's Standards, the transformer daily peak loading limits are expressed as percentages of the transformer's nameplate rating for summer normal, summer emergency, winter normal, and winter emergency. Re-rating the existing transformers based on the higher projected ambient temperatures could result in reduction of nameplate capacity; according to IEEE standard C57.91-2011 would roughly amount to 1.0% capacity loss per degree rise in ambient temperature over the manufacturer's ambient temperature rating. If the transformers are not re-rated, the increased operating temperature could result in accelerated transformer loss of life. In a warming climate due to climate change, Eversource expects some transformers to be de-rated, resulting in loss of capacity and the potential need for additional transformer capacity to offset the capacity loss due to increased ambient temperatures.

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 one of the critical indicators of 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 because of previous hours loading levels and ambient temperatures. In other words, loss of life for a transformer is accelerated when its hottest spot temperature is continuously high, in contrast with high periods followed by low load periods that allow the transformer to cool down. The hottest spot temperature can be elevated continuously due to continuously high ambient temperatures, such as those in a heat wave. This temperature rise is exacerbated by the fact that a heat wave increases demand and thus further increases transformer loadings. This is why the duration of heat waves, and the maximum daily temperatures are both highly influential climate variables for assessing the need to reevaluate transformer sizing and operating practices in the face of climate change.

Substations

With rising sea levels, coastal substations could be subjected to permanent water inundation. Rising sea levels also layer on top of potential acute flooding events due to storm surge/ hurricane activity. The results of the climate vulnerability study would indicate projected flood elevation levels due to sea level rise and storm surge and by extension, the substations at risk of flooding. Eversource already has Standards regarding the elevation of its existing and proposed stations, which are using the Federal Emergency Management Agency (FEMA) maps. FEMA defines Base Flood Elevation (BFE) as the elevation of surface water resulting from a flood that has a 1% chance of equaling or exceeding that level in any given year. Per the current Eversource Standards, existing coastal substation equipment should be elevated to BFE plus a buffer of 1 ft, while the minimum standard for new substations in coastal areas is BFE plus 3 feet (or FEMA's 500-year flood levels plus 1 foot, whichever is greater). (Lower elevations standards apply currently for existing and new substations that are not in coastal areas). As part of the climate resilience study, Eversource will assess whether the existing elevation Standards are adequate to cover the sea level rise projected as part of the climate study and which levels of storm surge would say existing Standards protect against. Potential proposed changes could be further substation elevation for targeted stations, universal station elevation standard changes or operational solutions like installing flood walls as part of Standards or for targeted stations.

Caveats of the Analysis

We note that the table and discussion above is focused on "primary" relations, meaning the asset types directly and significantly impacted by a climate hazards, but there are multiple secondary and tertiary effects too. For example, flooding due to storm surge may impact poles significantly, since the base of the pole can be submerged in water for limited time without short- or long-term impacts. Similarly, overhead conductors may be susceptible to increased corrosion due to sea level rise. Other examples not considered in this vein of work are indirect impacts like for example, the possibility of flood waters carrying material damaging to the pole, or even pushing objects onto the poles and making dents or increasing leaning angles. These secondary, tertiary direct and indirect effects can potentially end up being impactful; for example, the efficiency loss of heat pumps due to ambient temperatures can further exacerbates demand.

5.4. Grid Modernization and VVO (Proposed Investments)

5.4.1. Volt-Var Optimization (VVO)

One of the components of the modern grid will be advanced technologies aimed at actively managing voltage. This requirement becomes essential for multiple reasons, first and foremost, to ensure the distribution voltages remain within prescribed tolerances and are not moving up and down rapidly as additional distributed energy resources (DER), characterized by intermittent output, are added to the system. In addition, managing these voltages to reduce energy consumption and optimizing demand will provide direct benefits to customers. By deploying a Volt VAR Optimization (VVO) scheme on a distribution feeder, Eversource can improve the efficiency of this energy delivery, while at the same time dramatically increasing visibility into real-time grid conditions. VVO is the process of optimally managing voltage levels and reactive power to achieve more efficient grid operation with the benefit of reducing system losses and energy consumption and improving the management of peak demand. The result is lower costs for customers, decreased carbon emissions, and increased DER hosting capacity.

The concept of reducing service voltage to customers to reduce line losses and energy consumption is not new because utilities have long recognized that close to ten percent of the electricity produced by power plants is lost as it travels from the source to the end-user, with about forty percent of this loss occurring on the distribution system. In the 1990s, Eversource implemented programs known as conservation voltage reduction (CVR) by lowering voltage at the substation bus to a level that was expected to keep voltage within the +/- 5 percent tolerance range for all customers on the associated feeders and manually changing line regulator and capacitor bank settings. This CVR approach relied on using the lower end of the acceptable voltage range with customers closer to the substation having somewhat higher voltage than customers at the end of the feeder. This approach relied on calculations and models to determine the appropriate device settings that would be expected to produce the desired results under most conditions. Without real-time sensing, communication, and control of line regulators and capacitors, however, it proved difficult to achieve meaningful levels of savings while ensuring reliable, high-quality power service to customers. As the electric power grid became more complex over time with basic automation and increased penetration of DER, manual CVR techniques were increasingly insufficient, and the programs were abandoned.

Advanced grid technology and communications capabilities have the potential to be transformative for Eversource in its ability to implement voltage management programs. In particular, the ability of the DMS to collect voltage data from feeders in real-time, process the data, and immediately send commands to substation transformers, line regulators, and capacitor banks is a major departure from the CVR techniques. With visibility into real-time feeder conditions, a VVO system will reduce the potential for customers to experience high or low voltages. Customers are also less likely to experience voltage flicker, which can be caused by rapidly fluctuating output of intermittent resources such as solar inverters once devices are automatically controlled based on actual field conditions rather than static settings and system models.

When deployed in the Company's Massachusetts affiliate's service territory over the past several years, the Company's affiliate achieved a 2.1% reduction in distribution system losses and a 1.8% reduction in peak demand.

By investing $22.5M in capital assets from 2025-2029, Eversource can install the required devices to implement VVO on an estimated 10 to 12 substations and their feeders per year, which represents approximately 20% of the Eversource substations in New Hampshire.[39] While the exact benefit/cost ratio (BCR) depends on the substations ultimately chosen for this investment, representative analyses place the BCR between 1.2 and 1.4. The Company is certain it will build upon its successful deployments in Massachusetts to conceive, design, construct, and test VVO equipment and software in New Hampshire. The Company's transition towards active voltage management as an operational tool used to increase system efficiency and support the integration of DER represents a step change in creating a reliable, resilient, and cost-effective system for customers.

A key objective of the VVO program will be to determine the substation and feeder deployment strategy that will maximize benefit to customers. The Company will focus on areas that have high penetration of DER and areas where feeder and load characteristics maximize energy and demand savings. For instance, it is likely that relatively short, heavily loaded feeders will provide a greater benefit for energy savings, while less dense rural feeders with large DER integrated at the end of the feeder may provide greater benefit from a DER integration perspective. Over the five-year time horizon, the Company expects to deploy VVO on approximately 15 percent of the substations serving customer load and that have significant levels of DER connected.

5.4.1.1 VVO Investment Description

The VVO program has three investment components: The first is to deploy and/or upgrade the substation transformer load tap changers, substation feeder metering, feeder voltage regulators, and feeder capacitor banks to enable two-way communication (also known as SCADA) such that the devices can be actively controlled by a centralized system in response to real-time voltage and reactive power fluctuations. The second component is the centralized intelligence program used to collect real-time data from the system, perform analyses and calculations, and send control signals to devices.[40] The third component is the communications infrastructure needed to enable the two-way communication between the field devices and Eversource's centralized SCADA system.

[39] The exact number of substations at which the Company can deploy VVO will depend on the number of substation transformers that require upgrades to their load tap changers.

5.4.2. DERMS

The Company is also continuing to improve its core control room technologies through software upgrades that deliver additional functionality and capabilities. Distributed energy resources have the potential to play an important role in cost effectively achieving reliability goals and provide an opportunity to shift how the distribution system is operated to a more optimal state.

The potential use of DER to provide grid services is driving the need for a Distributed Energy Resource Management System (DERMS) to assist operators in managing DER assets. Increasingly, system operators will be challenged daily to monitor and control power flow on the distribution system in the presence of DER. The DERMS is a software platform that can manage DER to deliver grid services and provide operators a tool to balance demand with supply on the distribution network. To achieve the optimal use of distribution system assets, the DERMS will organize connected assets and provide critical operational data for each asset to be a data input into the DMS. The DERMS will also act as the system from which the system operator will be able to issue commands to the DER to guarantee the safe and reliable operation of the distribution system in real time. Another expected enhancement in this area is to build IT infrastructure to support the interoperability of the DERMS with other real time systems. It is critical to future growth to be able to share data efficiently between systems and having the IT infrastructure in place to improve interoperability will be critical. The Company does expect to progress this capability over time and is planning to start with a targeted deployment to include different types of assets within a specific geographic region of its service territory.

To go beyond monitoring and to take full advantage of these assets, there are many areas of need that are required to be addressed. To begin, the adoption of IEEE 1547-2018 requires DERs to be capable of active voltage regulation, disturbance ride through, and frequency response. These advanced the functionality of DER but also necessitates the collection of data for each asset and to build them into the model of the distribution system to effectively manage them. DER assets' nameplate data and operational setpoints don't reside in an operational system today. The DER type, model, output capability, site connection is critical information to know how to model these assets as part of the steady state model. In addition, control of operational modes and setpoints such as voltage, Volt/VAR, watt/frequency will be predicated on collecting the "as-left" settings and including those details in the model of the asset.

Today, there is no such system that has this data and can translate it into operational use for system operators to be able to act on local distribution conditions. Furthermore, if DER begins to be aggregated for multiple use cases, there will be a need to know how that aggregation is intending to use each asset and layer that data point on top of the individual asset information. An example of this is the potential impact Federal Energy Regulatory Commission (FERC) Order 2222 will have by establishing a path to the regional market for aggregated DERs which may compete with local distribution operating conditions. This complex situation of individual use versus aggregated use requires a system to manage the local, global, and contractual constraints that each DER potentially are subject to.

In addition to the operating tool, building out information system architecture that is interoperable and efficient to manage the sharing of data between operational systems is needed to enhance the capability. As information technology advances, the Company also needs to establish a more agile architecture to make adoption more “plug and play” in nature.

5.4.3. Advanced System Planning Tools

5.4.3.1 Advanced Forecasting

As the composition of customer load changes with the adoption of rooftop solar and electrification of previous other fuel sources, understanding, in detail, understanding the relationship between these trends and the expected load will become increasingly important. Future planning will require the ability to conduct scenario-based planning. Scenario-based planning capabilities will be enhanced with the implementation of a tool focused on robust forecasting of load and generation.

Currently, planning engineers use basic tools to forecast load and generation at the circuit level. This process involves a combination of “top down” allocation from regional forecasts and “bottoms up” understanding of expected step changes in load and generation. Using a traditional approach to forecasting, planners typically use assumptions including average load growth over wide areas, basic analysis of weather impacts, and have limited insight into changing economic, resource deployment, or network topology changes. A manual process is used to account for load masked by large generators, a process that is not feasible for smaller behind-the-meter solar facilities. Without accurate forecasts, planners must use conservative assumptions to ensure adequate system capacity. It is also difficult and time consuming to produce multiple scenarios of future load and generation penetration to enable probabilistic planning under a range of outcomes.

As a result of this initiative the Company will develop and deploy advanced forecasting capabilities in New Hampshire which will allow a detailed and automated assessment of bulk circuit level forecasts and support probabilistic modelling of scenarios for risk-based investment prioritization. For this purpose, the Company will leverage existing knowledge and capabilities to develop large scale power flow automation that can ingest the forecasts, conduct Monte Carlo simulations on various input parameters, and produce reports that inform distribution engineering, system planning, and regulators and policy makers on future investment decisions.

Furthermore, the Company will develop, as part of its advanced forecasting capabilities, long-term demand assessment approaches which provide a 20–30-year lookout on state policy objectives and macroeconomic trends. These results will then be used as inputs into solution design of projects to ensure the Company develops only those solutions that serve a long-term purpose.

The Company is hereby building on experiences from other jurisdictions where similar projects are already underway allowing leveraging of synergies for New Hampshire.

5.4.3.2 Hosting Capacity and Interconnection

Assessing the potential impact of DER on the system is an essential component of modern system planning. There is growing recognition in the electric power industry of the need to improve the efficiency and effectiveness of the study process to reduce time and lower costs for customers. The volume of applications and the complexity of analysis are increasingly stressing the limits of existing engineering resources and their current processes. These stresses are expected to grow as new drivers support the use small DER as aggregated resources that can be dispatched simultaneously in one area of the grid for a common objective. In recognition of these needs and limitations, in recent years, new software tools have been introduced to effectively automate portions of the study process. These tools increase capacity, reduce study time and free up high value resources to focus on more complex planning activities. Eversource has invested in tools and solutions including Synergi Electric, Hosting Capacity Maps. Additional tools used in the interconnection process include Power Systems Computer Aided Design (PSCAD) and Power Clerk. However, in order to better service our customers a more automated and streamlined approach needs to be considered.

The recent increase in interconnection applications as well as engagements with developers have shown that there is a need for more and better information, flexible interconnection processing for storage, and a faster turnaround for interconnection requests. In an effort to learn and understand how other utilities and jurisdictions approach this issue, Eversource has conducted a wide-ranging review of market technologies from North American and Europe as well as benchmarking discussions with peer utilities. Eversource found that in all cases, the key to improving and speeding up the interconnection review process is a unified software platform to combine and streamline relevant tools and processes.

In support of increasing the efficiency and effectiveness of the interconnection application study process, Eversource is proposing to procure a software solution to enhance the Company's capabilities to quickly and accurately assess interconnection impacts in order to safely and reliably interconnect as much DER as possible. As such, the Company will target the following areas.

Procurement of Software Solution: Eversource intends to purchase a software solution using the experience gain from previous vendor interactions. The intention is to provide a dedicated and specifically tailored solution to DER planners while leveraging investments made into Synergi, PSCAD and Power Clerk by increasing integration and automation between the tools. The Solution will be specifically tailored to the interconnection process.

Improvements to Customer Provided Data: 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.

Improvements to Hosting Capacity Calculations: A key component of the proposed solution is the active engagement with customers through a portal environment, providing easy access to guidance on improvements to their interconnection, which is based on the ability to compute ad hoc hosting capacity calculations. In addition to this ad hoc capability, hosting capacity calculations must be time series based to allow for the evaluation of specific operating modes and dispatch patterns.

Customer User Flow: Customers will have the ability to actively engage with the interconnection portal and receive direct feedback on possible constraints of their application. While this will not replace an interconnection study, modifying the interconnection to better fit the available grid capacity significantly reduces the risk of associated interconnection cost. Furthermore, it will provide developers with more information on options to utilize storage assets or other measures to actively reduce their possible cost to interconnect.

Interconnection Turn Around Time: Through automation of all feasible study steps and an improved case management, Eversource expects a reduction of effort, and consequently time, required to study the interconnection request. The result will manifest itself with faster turnaround times for interconnecting customers, which directly results in reduced risk to projects.

The Company is hereby building on experiences from other jurisdictions where similar projects are already underway allowing leveraging of synergies for New Hampshire.

5.5. Eversource Solar (Proposed Investments)

Appropriately sited solar can lower utility customer costs while supporting state energy goals. Recent changes to federal incentives have improved the cost effectiveness of solar technologies and provided regulated utilities with more options for monetizing federal tax credits on behalf of their customers. Given these developments, Eversource has been actively pursuing development of potential company-owned solar projects in New Hampshire on company-owned properties.

Under RSA 374-G, New Hampshire electric distribution companies are permitted to build, own and operate distributed generation under specific circumstances including when the benefits of such projects exceed the cost to ratepayers. In 2023, Unitil received PUC approval to own a 5MW solar project adjacent to its Kingston substation. This project was approved in recognition of the broad benefits it would provide to Unitil customers. Eversource intends to file several similar projects in the coming months with the PUC, seeking commission approval. The specific projects, their overall size and costs are currently under development. A filing with the PUC will be made after a competitive procurement for a solar contractor and a thorough analysis of the benefits and costs of the projects.

The Company's affiliates have significant experience developing large-scale solar projects in Massachusetts where company affiliates own 70 MW of solar across 22 individual sites. These Massachusetts projects were delivered at overall costs to ratepayers below prevailing solar market rates when they were constructed. The company intends to use the lessons learned building and operating these solar sites to benefit its development efforts in New Hampshire.

6.0 Investment Summary (Including Siting, Permitting, Supply Chain, and Workforce Risks)

The 2025-2029 DSP includes multiple categories of investments that will improve the safety, reliability, resiliency, and DER enablement capabilities of the Company's electric distribution system, delivering value to customers on many fronts. The total investment is approximately $1.4 billion in capital over the DSP five-year term and is focused on reliability and resiliency and includes technologies to assist in optimizing the grid.

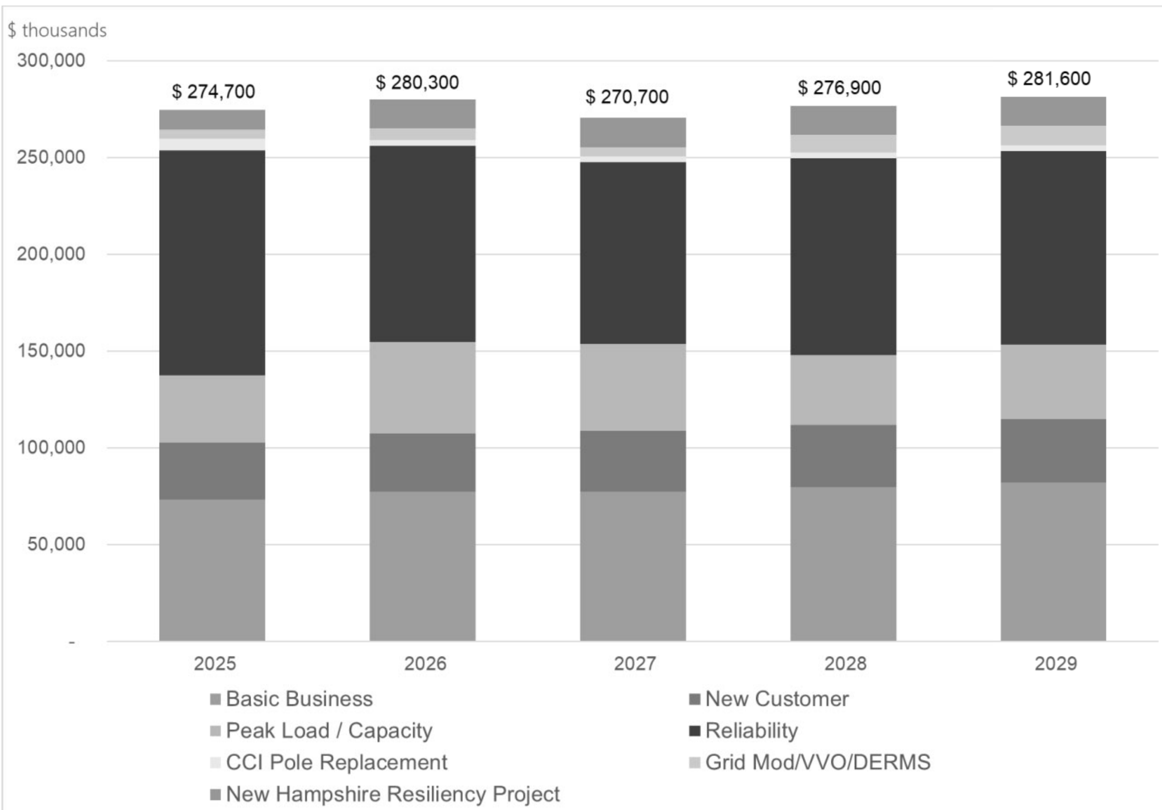


Figure 6-1: 2025-2029 Capital Investments ($K)

Capital investments are divided into the following two categories:

1. **Core Investments – 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.
    a. **Peak Load and Capacity:** Upgrades and new build of substations and distribution lines to accommodate load growth over the ten-year planning horizon.

b. **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).

c. **Reliability:** Upgrades to overhead and underground infrastructure to ensure reliable service, including hardening, conversions, aging infrastructure replacements, and automation.

d. **New Customer:** Investments to provide infrastructure for new customer loads that are coming on-line.

e. **CCI Poles:** Capital investments required to replace zero life poles in the areas previously maintained by Consolidated Communications ("CCI") because of the transfer of CCI ownership interest in these poles to the Company as of May 1, 2023. As approved in the New Hampshire Public Utilities Commission issued Order No. 26,729 on November 18, 2022, these investments include replacements required based on information received from CCI and from ongoing pole inspections of the newly acquired poles.

2. **Resiliency and Grid Modernization (Proposed Investments):** Proposed capital investments to harden the distribution system against climate change threats, improve control room technology, optimize the system through voltage management, and provide addition planning tools for future forecasting.

   a. **Grid Modernization Technology:** Capital expenditures to improve its core control room technologies with a DERMS system, build technology platforms required to optimize voltage management (VVO), and support advanced forecasting engineering. (See Section 5.4 for further description of proposed investments)

   Resiliency: Incremental capital investments in hardening distribution system infrastructure to address impacts of climate change as identified by recent climate impact analysis. (See Section 5.3 for further description of proposed investments).

6.1. Customer Benefits

The Company's five-year investment plan will deliver a portfolio of customer benefits.

- **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, which 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.

- **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. This includes strategic system hardening investments like reconductoring and undergrounding as well as vegetation management. These reliability investments target improvements in the Company's existing SAIDI and System Average Interruption Frequency Index (SAIFI) metrics. As described in Section 5, the Company's new resiliency program is targeting a 4.3% reduction in all-in SAIDI over 10 years with a $150M investment. A multitude of further customer benefits emanate from shorter and/or less outages. Customer experience in the area is improved beyond what this reliability improvement if the customers of NHEC (New Hampshire Electric Cooperative) fed by hardened feeders are considered.

6.2. Execution Risks – Siting, Permitting, Supply Chain and Workforce Challenges

6.2.1. Siting and Permitting Execution Risks

The DSP projects described in this section 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 DSP is focused on distribution; however, bulk substations will require increased transmission capacity at a similar scale. In addition to projects outlined in the DSP, 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 may 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.

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. The Company has expanded its Siting, Licensing and Permitting, and Project Services groups to keep pace with growing demand while continuing to produce timely, consistent, and comprehensive project filings, and to address issues and continue engagement throughout the review process (as appropriate). Once a project has been approved and permitted, communication with the community and impacted stakeholders continues, while 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.

6.2.2. 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 the 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.

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.

When it comes to supply chain execution risks, rapidly changing technologies will introduce challenges to ongoing equipment maintenance and future design considerations. For example, SF6 (Sulphur Hexafluoride) is a very potent greenhouse gas. Eversource is currently piloting non-SF6 electrical equipment to help evaluate how SF6 may be phased out in the future. Currently, non-SF6 alternatives are expensive, and the supply chain industry is not yet equipped to fully support a rapid change.

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 and must find new ways to address uncertainty in future equipment costs.

Cybersecurity continues to grow and is a critical focus of the utility industry as more products in the field are software and cloud based. As the world grapples with how to deal with addressing new cyber 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.

6.2.3. Workforce Challenges

Ensuring a prepared workforce capable of deploying and effectively operating innovative grid technologies is a crucial component for a successful implementation of the DSP. Although all utilities in NH and throughout New England are facing similar workforce obstacles, the following challenges have been identified by Eversource, along with the strategies adopted to address them.

6.2.3.1 Current Employment Market Landscape

With historically low unemployment rates in NH, 2.6% in April 2024, employers such as Eversource do encounter a scarcer pool of candidates than in previous years. 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.

6.2.3.2 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 Sections 2.4.1 and 2.4.2).

6.2.3.3 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.

6.2.3.4 Attrition and Retention

Given the vibrancy of the NH 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.

Table 6-1: Eversource 2022 Retention Rates

We continue to listen to employees through surveys, town hall meetings and online employee groups, and work to engage them. Turnover is also an opportunity to continue diversifying our workforce.

	AMERICAN INDIAN OR ALASKA NATIVE	ASIAN	BLACK OR AFRICAN AMERICAN	HISPANIC OR LATINO	NATIVE HAWAIIAN OR OTHER PACIFIC ISLANDER	OTHER	TWO OR MORE RACES	WHITE	TOTAL
FEMALE	90.00%	89.74%	85.85%	83.71%	100.00%	90.91%	89.66%	89.05%	**88.27%**
MALE	92.86%	85.39%	90.02%	93.35%	50.00%	103.85%	91.67%	91.28%	**91.25%**
TOTAL	**92.11%**	**86.72%**	**88.30%**	**90.33%**	**75.00%**	**101.59%**	**91.15%**	**90.75%**	**90.48%**

2022 data: Eversource and Aquarion combined.

6.2.3.5 Fostering the Energy Industry and Eversource's Workforce

Eversource continuously looks for innovative ways to replenish the workforce by expanding and refining its programs because business needs are evolving. Broadening the candidates' pool is a challenge faced among all utilities and businesses in other industries. Through the establishment of dedicated programs aimed at engaging communities and organizations that represent all populations, Eversource aims to attract exceptional talents from a wide range of diverse candidates to its 1,300 strong employee workforce in NH.

Eversource partners with New Hampshire's Manchester Community College (MCC), the International Brotherhood of Electrical Workers (IBEW) Locals 104 and 1837, and the National Electrical Contractors Association (NECA) to offer a certificate program that upskills diverse candidates and prepares graduates for line worker apprenticeships. Eversource is also working with MCC to build a pipeline of candidates working to obtaining degrees in Electrical Technology by partnering with internship and career opportunities for substation electricians.

The University of New Hampshire (UNH) is another strong partnership, in addition to partnering for internship and career opportunities; Eversource sponsors the UNH Clean Energy Scholarship & Internship program. This program is designed to provide students with financial assistance while providing an opportunity for career exploration, training, and a varied work experience. Each student selected for the UNH Clean Energy Scholarship & Internship, will participate in a 10–12-week paid internship at a New Hampshire Eversource facility.

As the hiring needs related to the DSP 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. In addition to workforce development, Eversource has developed a Supplier Diversity Program that provides value for the Company while positively impacting diverse businesses, which include minority and women-owned businesses, and the communities they operate within.[41] In 2022, Eversource's number of diverse suppliers reached 297, the highest achieved to date by the Company. Eversource is also strengthening its internal approach to supplier diversity. Eversource actively identifies, develops, and does business with diverse suppliers that reflect the market, customers, and communities that the Company serves.

As the Company remains committed to fostering diversity in the energy sector, Eversource is cognizant of the substantial efforts required to achieve this objective. Nonetheless, as a result Eversource's commitments to diversity, the Company's workforce is becoming more diverse encompassing its board of trustees, employees, new hires, and internal promotions which are highlighted in the Company's Diversity, Equity and Inclusion Report, 2022 for a summary of the Company's key metrics with respect to diversity, equity, and inclusion.[42] In addition, in 2023, the Company received multiple awards recognizing its efforts to ensure a diverse, equitable, and inclusive workplace.[43][44][45][46]

[41] https://www.eversource.com/content/docs/default-source/community/2022-eversource-dei-report.pdf
[42] For more information on Eversource's diversity efforts, see "Diversity, Equity & Inclusion Report 2022", https://www.eversource.com/content/docs/default-source/community/2022-eversource-dei-report.pdf.
[43] Just Capital. "2023 Overall Rankings," January 10, 2023. https://justcapital.com/rankings/.
[44] "Gender Equality Index Member List." Bloomberg. February 2023. https://assets.bbhub.io/company/sites/51/2023/02/GEI-MemberList.pdf
[45] "Workplace Equity Scorecard Large-Cap 3000." As You SOW. September 30, 2023. https://www.asyousow.org/report-page/workplace-equity.
[46] "Workplace Equity Scorecard Large-Cap 3000." As You SOW. September 30, 2023. https://www.asyousow.org/report-page/workplace-equity.

7.0 CONCLUSION

Through the DSP, Eversource has highlighted a clear path to achieve its objectives of addressing aging infrastructure to support reliability, supporting increasing demand due to economic growth and DER adoption, maintaining safe and reliable service at a measured pace of investment, and highlighting the need for improved resiliency to address increasing impacts from extreme weather events.

Addressing aging infrastructure is a foremost priority for the Company. Eversource has an obligation to monitor its assets and implement required replacement to deliver safe and reliable service. As highlighted in Section 2.4.5, 15% NH of substation transformers are older than 60 years and 12% of breakers which are at or over 50 years old. Eversource has adopted a comprehensive method to assess the health of its assets which does not rely solely on age (see Section 2.4.5 and Section 3.3). Additionally, Eversource performs inspections, field monitoring and testing, to evaluate the health of the infrastructure. The collected asset inspection data is used for further asset health assessment analyses according to industry standards.

The DSP addresses the need to support increasing loads due to economic growth in the state. Eversource is using a demand forecast methodology to identify the needs for upgrades of the EPS. Using this method, the Company has forecasted the need to implement a series of projects. Notably, Eversource is planning or proposing the rebuilding of the Dover substation, the Portsmouth 12 kV capacity project, the Salmon Falls capacity project, and the South Milford capacity project (see Section 5.1.1). Additionally, Eversource is proposing distribution circuit capacity upgrades to supporting projected overload of step transformers or distribution substation transformers, and expansion and voltage upgrades of circuits.

The DSP includes multiple categories of investments aimed at improving the safety, reliability, resiliency, and DER enablement capabilities of the Company's electric distribution system, delivering value to customers (see Chapter 6). The DSP includes proposed resilience, grid modernization, and solar programs that could be deployed in addition to the core investments described in the DSP to further benefit customers.

The total investment is approximately $1.4 billion[47] in capital over the DSP five-year term and is focused on reliability and resiliency and includes technologies to assist in optimizing the grid. Investments include peak load capacity upgrades, basic business, reliability upgrades, basic business-related upgrades related to new customer loads, and communication (CCI). Grid Modernization investments include the deployment of a DERMS system, VVO, and supporting advanced planning tools and processes.

With three catastrophic hurricanes since 2010, a significant winter snowstorm in 2011, and many other additional storms resulting in a substantial number of outages in the past several years,

[47] The total budget does not include costs related to the Company-owned solar program discusses in Section 5.5.

devastating weather events in New England are becoming more frequent. Eversource is proposing incremental capital investments in hardening the distribution system infrastructure to address resiliency challenges posed by climate change impacts (see Section 5.3). Eversource's resiliency analyses highlight the need for upgrading conductors (underground and overhead) and transformers to higher ratings. Rising sea levels require Eversource to assess the flooding risks posed to substations which may require substation elevation for targeted stations and universal elevation standard changes or operational solutions such as installing flood walls.

The DSP aligns with many of the goals outlined in the *"New Hampshire 10-Year State Energy Policy"* as highlighted below:[48]

- Goal 1: "*Prioritize cost-effective energy policies*." By proposing smart and targeted investments, the DSP will bring substantial benefits to Eversource's customers including safety, reliability, resiliency, and DER enablement capabilities. All these investments are reviewed for alternatives and the most cost-effective solutions are selected.

- Goal 2: "*Ensure a secure, reliable, and resilient energy system*" is fully addressed by the DSP. As already highlighted in the DSP, Eversource's foremost priority is to ensure safe and reliable service to its customers. As highlighted through this document, safety is a core value at Eversource (section 6.1), and Eversource has a regulatory requirement to comply with all the relevant safety codes and procedures (Section 3.1). Reliability is extensively discussed in the DSP in Sections 5.2 and Section 5.3.

- Goal 3: "*Adopt all-resource energy strategies and minimize government barriers to innovation*": by considering the forecasted growth of DER, the DSP supports a greater increase of diversification of energy generation in the state (Section 2.4.2 and Section 5.1.3). The DSP proposes investment in innovative technology solutions including VVO, DERMS, advanced forecasting, and hosting capacity and interconnection (see Section 5.4).

- Goal 4: "*Achieve cost-effective energy savings, State Energy Efficiency Programs*". As an NHSaves utility program administrator, Eversource offers energy efficiency programs across all customer segments, including residential customers of all income brackets, municipalities, and commercial and industrial (C&I). These programs led to significant reduction in energy savings for customers. (see Section 4.2.1).

- Goal 5: "*Achieve environmental protection that is cost-effective and enables economic growth*", Goal 8**: "***Generate in-state economic activity without reliance on permanent subsidization of energy,*" and Goal 9: "*Protect New Hampshire's interests in regional energy matters*". By supporting the integration of DER in the state with the DSP, Eversource is actively channeling the transition toward a clean energy-economy which

[48] *"New Hampshire 10-Year State Energy Strategy"*, July 2022
https://www.energy.nh.gov/sites/g/files/ehbemt551/files/2022-07/2022-state-energy-strategy.pdf

has significant potential for economic growth (see 2.4.2. and 5.1.3.). In addition, the forecasted growth of the share of renewable energy, channeled through DER integration, will strengthen the state's energy self-reliance.

- Goal 10: "*Ensure that appropriate energy infrastructure is able to be sited while incorporating input and guidance from stakeholders*": as highlighted in Section 2.1.6, State permitting provide opportunities to engage municipalities, residents and other stakeholders in planning and review of the electric system and related projects. As the energy sector moves toward a cleaner energy future, the opportunities and challenges of this transition must be considered with a commitment to maximize benefits to customers.

Through the DSP, Eversource provides to its customers, regulators, policymakers, stakeholders, and the general public a comprehensive overview of the challenges facing the grid and the solutions to address them over the next five and ten years. The solutions proposed by Eversource are critical and consequential investments for the Company to continue delivering safe, reliable and resilient service to its customers while addressing key issues including aging infrastructure, load and DER growth, evolving customer needs, and grid modernization requirements. This transparency invites a thorough review of the DSP by all interested stakeholders. Eversource looks forward to receiving feedback and recommendations on the DSP as the Company and stakeholders engage in the rate case process.

8.0 Appendix

8.1. Glossary and Acronyms

8.1.1.1 Glossary

Term	Definition
Ancillary Structures	Ancillary structures encompass structures which are an integral part of the operation of any transmission line. The term "ancillary structure" has been interpreted by the EFSB to include substations or switching station additions.
Behind-the-Meter (BTM)	BTM refers to DER installations located on the customer side of the electric meter. It typically involves rooftop solar panels, residential energy storage systems, demand response, and other DERs that are installed at individual homes or businesses.
Blue-sky	Days without storms.
Breaker (circuit breaker)	A circuit breaker is a device designed to provide protection to the circuit during an abnormal condition. The breaker automatically breaks current when it detects fault conditions such as overcurrent or short circuit.
Bridge to Wires	Bridge to Wires refers to the use of existing DER, dispatched by Eversource System Operations, to add operational flexibility in areas with growing demand where traditional solutions are required.
Bus Work	In a bulk substation, bus work is a group of rigid conductors typically made of aluminum or an alloy that serve as a common connection between the other components of the substation.
Capacity	The rated and continuous load-carrying ability, expressed in megawatts or megavolt-amperes, of generation, transmission, or other electrical equipment.
Cascade	Cascade is a software application that serves as the Company's asset repository and system of record for substation equipment.
Customer Average Interruption Duration Index (CAIDI)	Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service after an event. CAIDI is typically measured in minutes.
Demand Response (DR)	DR includes any load that is flexible in its consumption and can, through external triggers or incentives, be made to change its behavior. This can include traditional DR solutions such as heating and cooling, or up and coming solutions such as charge management.
Distributed Energy Resource (DER)	DERs include a wide variety of distributed generation (DG) resources, energy storage systems (ESS), or flexible load commonly referred to as demand response (DR) that are controllable and connected to the distribution system.
Distributed Energy Resource Management System (DERMS)	Control room tool to manage, monitor, and dispatch DER based on real time system conditions. DERMS is a foundational platform capability intended to increase the efficiency and effectiveness of DER integration and to enable the use of DER as a grid asset.
Distributed Generation (DG)	DG include a wide variety of generation resources connected to the distribution system that either export to the distribution system or are intended for behind the meter self-consumption.
Distribution	The delivery of electricity to end users via low-voltage electric power lines.
Electric Power System (EPS)	The EPS refers to the network of components and systems designed to generate, transmit, distribute, and regulate electrical power to end-use customers. See section 2.1.1 for more detailed description and graphic depiction of the EPS. This DSP is focused on the distribution system segment of the EPS.

Energy Efficiency (EE)	EE represents programs that have created a permanent, non-dispatchable load reduction through improvement to building systems, structures, or operations.
Energy Storage System (ESS)	ESS include any technology that can store energy for any amount of time and discharging that energy as electric power. ESS can include chemical storage systems such as lithium-ion systems or other modes of storage, such as pumped hydro.
Enterprise Energy Control System (eECS)	The Company's combined transmission and distribution SCADA system. eECS provides system operators with visibility and control of remote substation and distribution line devices with communications capability.
Environmental Benefits	Based on current state law, Environmental Benefits means the access to clean natural resources, including air, water resources, open space, constructed playgrounds and other outdoor recreational facilities and venues, clean renewable energy course, environmental enforcement, training, and funding disbursed or administered by EEA.
Feeder	Feeders are electrical circuits emanating from a substation that supply underground areas at distribution level voltages. Feeders do not supply customer level transformers directly except for underground network areas.
FERC 2222	The Federal Energy Regulatory Commission (FERC) issued Order No. 2222 in 2020, with updates in 2021. The main goal of Order No. 2222 is to better enable distributed energy resources (DERs) to participate in the electricity markets run by regional grid operators.
Flexible Interconnections	Flexible Interconnections allow DER to interconnect to the distribution system with agreed upon operating constraints that reduce the need for system modifications. See 6.3.2.1.
Flexible Services	See Grid Services Solutions.
Front-of-the-Meter (FTM)	Front of the Meter usually refers to activities, technologies, or systems that are located on the utility side of the electricity meter. For this DSP it typically refers to utility-scale ESS.
Generation	The production of electric energy.
Geographic Information System (GIS)	The GIS system is the as-built asset repository which is the primary source model of the distribution system. The GIS asset and connectivity model serves as the source system for real time operations, and system planning models.
Grid Services Solutions	Dispatch of customer owned aggregated BTM and third-party FTM DER to manage system constraints in real time to cost effectively address local capacity constraints or better optimize voltage levels.
Headroom	Headroom refers to the margin of available capacity at a specific equipment to accommodate additional load without causing violations of equipment specifications.
Heat Pump (Air Source ASHP) or (Ground Source GSHP)	A heat pump is a device capable of heating and cooling a building. During the heating mode, a heat pump extracts heat from an external source (air or ground) and transfers it into the home. In the cooling mode, the process is reversed, and heat is taken from indoor air and expelled outside.
Hosting Capacity	Hosting capacity is the estimated maximum amount of energy from a distributed resource (such as solar panels) that can be accommodated on the distribution system at a given location. This capacity is under existing grid conditions and operations without requiring significant infrastructure upgrades. This capacity takes into consideration safety, power quality, reliability, or other operational criteria.
Interconnection	The connection of DERs to the power grid that ensures safe operations in all grid conditions.
Inverter	An inverter is a device that converts direct current (DC) electricity, which is what a solar panel generates or energy storage system discharges, to alternating current (AC) electricity, which the electrical grid uses to serve load.
Load	The demand for electricity; electricity consumption; the amount of electric power delivered to any specified point on a system, accounting for the requirements of the customer's electrical equipment.

Maximo	Maximo is the work and asset management software application in use for the distribution system.
Meaningful Involvement	Based on current state law, Meaningful Involvement means that all neighborhoods have the right and opportunity to participate in energy, climate change, and environmental decision-making including needs assessment, planning, implementation, compliance and enforcement, and evaluation, and neighborhoods are enabled and administratively assisted to participate fully through education and training, and are given transparency/accountability by government with regard to community input, and encouraged to develop environmental, energy, and climate change stewardship.
Non-Traditional Solution	Alternative approaches to meeting system need. These solutions are Company owned and operated non-traditional approaches compared to the traditional system upgrade solutions. Section 6.3.2.1.
Non-Wires Alternatives (NWA)	NWAs are technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations. The technologies can include distributed energy resources, such as microgrids or batteries, and practices and programs focused on load management, demand response or energy efficiency.
Outage Management System (OMS)	The OMS is a detailed network model of the distribution system based on Eversource's GIS. By combining the locations of outage calls from customers, a rules engine is used to predict the locations of outages. OMS data is also used to provide customers with detailed information regarding their outage.
Outage Prediction Model (OPM)	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.
Peak Load	Peak load refers to the highest electricity demand experienced by the grid during a specific period.
Peak Shaving	Peak shaving refers to a strategy to reduce or "shave" the peak electricity demand during periods of highest usage.
Recloser	Reclosers are pole-mounted distribution line equipment which automatically respond to faults by opening to isolate the sections of circuits that are damaged.
Reliability	The assurance that electric power is available even under adverse conditions, such as storms or outages of generation or transmission lines.
Resiliency	Resiliency is the ability of the grid to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy-dependent services.
Step Load	Step Loads represent large (> 500kW or >1 MW depending on system) new load additions which can come from new buildings, or redevelopment of existing sites. These step loads can include residential developments, C&I, large standalone storage systems, fleet charging operations, and more. See Section **Error! Reference source not found.**.
Substation	A Bulk Power Substation steps down transmission level voltages (typically 69kV and above) to Distribution level voltages (typically below 69kV). See section 4.1.3 for an overview of bulk distribution substations.
Supervisory Control and Data Acquisition (SCADA)	SCADA is the system used for visibility and control of the grid.
Synergi	Synergi refers to a simulation tool, DNV Synergi Electric, used to develop advanced load flow capability. Synergi is also referred to as, "Advanced Load Flow."
System Average Interruption	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.

Duration Index (SAIDI)	
System Average Interruption Frequency Index (SAIFI)	SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period, typically a year.
The Company	PSNH d/b/a Eversource Energy
Transformer	A transformer is a device that step-down or step-up the level of voltage.
Transmission	The transporting of electricity through high-voltage lines to distribution lines.
TripSaver	Specific commercial name of a single-phase recloser.
Virtual Power Plant (VPP)	Aggregation of DERs to utilize for grid purposes.
Volt-Var Optimization (VVO)	Volt/VAR Optimization is a technology designed to manage voltage levels and reactive power flow to optimize the efficiency of the distribution grid. See Section 6.3.1.5. for more details.

8.1.1.2 Acronyms

Acronym	Definition
ABR	Automatic Bus Restoral
AC	Alternating-Current
ACEEE	American Council for an Energy-Efficient Economy
ACOE	Army Corps of Engineers
ACT	California's Advanced Clean Trucks Rule
ADMS	Advanced Distribution Management System
ADR	Active Demand Response
ADR	Active Demand Response
AESC	Association of Executive Search and Leadership Consultants
AF	Alternate Fuel
AHI	Asset Health Index
AI	Artificial Intelligence
ABR	Automatic Bus Restoral
AIS	Air Insulated Substation
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARR	Annual Reliability Report
ASAP	Affordable Solar Access Program
ASHP	Air-Sourced Heat Pump
AWC	Eversource's Area Work Center
BCR	Benefit Cost Ratio
BEA	Bureau of Economic Analysis
BESS	Battery Energy Storage System
BIPOC	Black, Indigenous and People of Color

Acronym	Definition
BTM	Behind the Meter
C	Celsius
C&I	Commercial and Industrial
CA	California
CAIDI	Customer Average Interruption Duration Index
CEMI-6	Customers Experiencing Major Outage - Percentage of customers experiencing longest interruption duration of six or more hours, excluding major events
CI	Customer Interrupted
CMI	Customer Minutes Interruption
CO	Carbon Monoxide
CO2	Carbon Dioxide
CVR	Conservation Voltage Reduction
DC	Direct-Current
DE&I	Diversity, Equity, and Inclusion
DEMI-3	Devices Experiencing Multiple Interruption – Devices that faulted three times in a given year
DER	Distribution Energy Resources
DERMS	Distribution Energy Resources Management System
DERPG	Eversource Distributed Energy Resource Planning Guide
DGA	Dissolved Gas Analysis
DG	Distributed Generation
DHR	New Hampshire, Natural Heritage Bureau, Division of Historic Resources
DMS	Distribution Management System
DNAF	Distribution Network Advanced Functions
DNCR	New Hampshire Division of Natural and Cultural Resources
DOE	U.S. Department of Energy
DR	Demand Response
DRWG	Distribution Reliability Working Group
DSCADA	Distributed Supervisory Control and Data Acquisition
DSP	Distribution System Plan
DSPG	Eversource Distribution System Planning Guide
DTT	Direct Transfer Trip
EDC	Electric Distribution Company
EE	Energy Efficiency
eECS	Enterprise Energy Control System
EEI	Edison Electric Institute
EFSB	Energy Facilities Siting Board
EMS	Energy Management System
EMT	Electromagnetic Transient
EPA	U.S. Environmental Protection Agency
EPS	Electric Power System

Acronym	Definition
ESCC	Electric System Control Center
EV	Electric Vehicle
F	Fahrenheit
FAN	Field Area Network
FERC	U.S. Federal Energy Regulatory Commission
FISR	Fault Isolation and Service Restoration
FTM	Front of the Meter (usually solar or battery)
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GHz	Gigahertz
GIS	Geographic Information System
GMP	Gross Metropolitan Product
GPS	Global Positioning System
GSHP	Ground-Sourced Heat Pump
GW	Gigawatt
HVAC	Heating Ventilation and Air Conditioning
IBEW	International Brotherhood of Electrical Workers
IEEE	Institute of Electrical and Electronics Engineers
IIJA	Infrastructure Investment and Jobs Act
IoT	Internet of Things
IP	Internet Protocol
IRR	Internal Rate of Return
ISO-NE	Independent System Operator - New England
IT	Information Technology
IVR	Interactive Voice Response
kV	Kilovolt
kW	Kilowatt
kWH	Kilowatt Hour
LCC	Load Carrying Capacity
LI	Low-Income
LMI	Low-to-Moderate Income
LOCA	Localized Construction Analogue
LRP	Eversource's Long-Range Plan
LTC	Load-Tap-Change
LTE	Long-Term Emergency
MCC	Manchester Community College
MDMS	Meter Data Management System
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatt

Acronym	Definition
NECA	National Electrical Contractors Association
NERC	North American Electric Reliability Corporation
NH	New Hampshire
NHDES	New Hampshire Department of Environmental Services
NH DOE	New Hampshire Department of Energy
NH DOT	New Hampshire Department of Transportation
NHF&G	New Hampshire Fish and Game Department
NPCC	Northeast Power Coordinating Council inc.
NPV	Net Present Value
NWA	Non-Wires Alternatives
O&M	Operation and Maintenance
OCB	Oil Circuit Breaker
OH	Overhead
OMS	Outage Management System
OPM	Outage Prediction Model
PEAT	Eversource Pro-Equity Advisory Team (PEAT)
PLOS	Planned Outage Study
PSCAD	Power Systems Computer Aided Design
PSNH	Public Service of New Hampshire
PV	Solar Photovoltaic
ROW	Right-of-Ways
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEC	Site Evaluation Committee
SF6	Sulfur Hexafluoride
SPP	Shared Socioeconomic Pathways
SS	Substation
SSP	Shared Socioeconomic Pathways
T&D	Transmission and Distribution
UG	Underground
UNH	University of New Hampshire
V	Volt
VA	Volt-Ampere
VPP	Virtual Power Plant
VVO	Volt Var Optimization
W	Watt
WAP	Weatherization Assistance Program
WTHI	Weather Temperature Humidity Index

8.2. Historical Substation Loading

A discussion on the overall state of the distribution system is presented in Section 2.2. The following is a detailed look at the loading and capacity utilization of each of Eversource's bulk substations in New Hampshire. While making the most of installed system capacity, high utilization of substation capacity reduces and can eliminate the load carrying capacity during single contingency events, planned or unplanned. Without the ability to carry load during contingent events, customer reliability decreases.

8.2.1. Central Region

	Bedford Substation			**Eddy Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	59.8	89.6	67%	64.3	89.6	72%
2015	64.2	89.6	72%	60.8	89.6	68%
2016	57.7	89.6	64%	65.2	89.6	73%
2017	54.7	89.6	61%	54.3	89.6	61%
2018	59.0	89.6	66%	65.1	89.6	73%
2019	58.5	89.6	65%	64.9	89.6	72%
2020	61.6	89.6	69%	63.0	89.6	70%
2021	61.6	89.6	69%	66.3	89.6	74%
2022	60.7	89.6	68%	63.4	89.6	71%
2023	56.1	89.6	63%	56.7	89.6	63%
Min	54.7	89.6	**61%**	54.3	89.6	**61%**
Max	64.2		**72%**	66.3		**74%**

	Garvins Substation			**Huse Road Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	*No data*	134.4		70.5	92.8	76%
2015	*No data*	134.4		67.6	92.8	73%
2016	66.9	134.4	50%	71.9	92.8	77%
2017	62.8	134.4	47%	64.5	92.8	69%
2018	67.7	134.4	50%	69.5	92.8	75%
2019	67.4	134.4	50%	66.9	92.8	72%
2020	67.2	134.4	50%	64.4	92.8	69%
2021	74.9	134.4	56%	71.3	92.8	77%
2022	70.5	134.4	52%	67.9	92.8	73%
2023	66.9	134.4	50%	62.6	92.8	67%
Min	62.8	134.4	**47%**	62.6	92.8	**67%**
Max	74.9		**56%**	71.9		**77%**

	Oak Hill Substation			**Pine Hill Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	*No data*	89.8		51.0	89.6	57%
2015	*No data*	89.8		52.3	89.6	58%
2016	61.5	89.8	69%	54.8	89.6	61%
2017	56.2	89.8	63%	51.5	89.6	57%
2018	61.7	89.8	69%	56.1	89.6	63%
2019	58.6	89.8	65%	54.9	89.6	61%
2020	65.4	89.8	73%	57.0	89.6	64%
2021	64.4	89.8	72%	58.8	89.6	66%
2022	61.4	89.8	68%	58.1	89.6	65%
2023	58.7	89.8	65%	57.5	89.6	64%
Min	56.2	89.8	63%	51.0	89.6	57%
Max	65.4		73%	58.8		66%

	Reeds Ferry Substation			**Rimmon Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	31.2	44.8	70%	55.3	44.8	123%
2015	30.8	44.8	69%	55.6	44.8	124%
2016	32.0	44.8	72%	63.1	89.6	70%
2017	30.7	44.8	69%	61.1	89.6	68%
2018	32.1	44.8	72%	62.2	89.6	69%
2019	29.0	44.8	65%	59.1	89.6	66%
2020	31.9	44.8	71%	63.1	89.6	70%
2021	32.5	44.8	72%	64.4	89.6	72%
2022	32.3	44.8	72%	62.9	89.6	70%
2023	29.6	44.8	66%	59.7	89.6	67%
Min	29.0	44.8	**65%**	55.3	89.6	**62%**
Max	32.5		**72%**	64.4		**72%**

	Weare Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	22.9	44.8	51%
2015	25.0	44.8	56%
2016	25.3	44.8	56%
2017	23.9	44.8	53%
2018	26.1	44.8	58%
2019	24.8	44.8	55%
2020	29.8	44.8	67%
2021	26.6	44.8	59%
2022	26.3	44.8	59%
2023	26.2	44.8	59%
Min	22.9	44.8	**51%**
Max	29.8		**67%**

8.2.2. Eastern Region

	Brentwood Substation			Dover (Cocheco Street) Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	21.2	44.8	47%	70.7	89.6	79%
2015	21.8	44.8	49%	71.4	89.6	80%
2016	23.6	44.8	53%	74.9	89.6	84%
2017	22.3	44.8	50%	70.5	89.6	79%
2018	24.6	44.8	55%	79.0	89.6	88%
2019	23.7	44.8	53%	75.2	89.6	84%
2020	25.5	44.8	57%	80.3	89.6	90%
2021	25.6	44.8	57%	80.6	89.6	90%
2022	24.9	44.8	56%	77.8	89.6	87%
2023	24.1	44.8	54%	70.3	89.6	79%
Min	21.2	44.8	**47%**	70.3	89.6	**79%**
Max	25.6		**57%**	80.6		**90%**

	Great Bay Substation			Madbury Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	36.0	44.8	80%	69.0	89.6	77%
2015	34.5	44.8	77%	61.7	89.6	69%
2016	37.5	44.8	84%	71.8	89.6	80%
2017	36.1	44.8	80%	65.9	89.6	74%
2018	39.6	44.8	88%	77.7	89.6	87%
2019	37.7	44.8	84%	67.5	89.6	75%
2020	38.2	44.8	85%	70.8	89.6	79%
2021	39.2	44.8	87%	71.8	89.6	80%
2022	44.6	44.8	100%	69.0	89.6	77%
2023	39.0	44.8	87%	67.3	89.6	75%
Min	34.5	44.8	**77%**	61.7	89.6	**69%**
Max	44.6		**100%**	77.7		**87%**

Year	Mill Pond Substation Load (MW)	Mill Pond Nameplate Capacity (MVA)	Mill Pond Load % of Capacity	Ocean Road Substation Load (MW)	Ocean Road Nameplate Capacity (MVA)	Ocean Road Load % of Capacity
2014				37.9	89.6	42%
2015	3.3	30.0	11%	33.6	89.6	38%
2016	9.2	30.0	31%	39.2	89.6	44%
2017	8.6	30.0	29%	30.9	89.6	35%
2018	10.3	30.0	34%	31.3	89.6	35%
2019	9.7	30.0	32%	32.0	89.6	36%
2020	10.2	30.0	34%	32.9	89.6	37%
2021	11.6	30.0	39%	35.4	89.6	39%
2022	10.4	30.0	35%	36.6	89.6	41%
2023	9.5	30.0	32%	26.7	89.6	30%
Min	3.3	30.0	**11%**	26.7	89.6	**30%**
Max	11.6		**39%**	39.2		**44%**

Year	Portsmouth Substation Load (MW)	Portsmouth Nameplate Capacity (MVA)	Portsmouth Load % of Capacity	Resistance Substation Load (MW)	Resistance Nameplate Capacity (MVA)	Resistance Load % of Capacity
2014	36.3	44.8	81%	23.1	44.8	52%
2015	34.5	44.8	77%	19.5	44.8	44%
2016	38.3	44.8	86%	19.1	44.8	43%
2017	35.5	44.8	79%	20.6	44.8	46%
2018	36.9	44.8	82%	21.3	44.8	48%
2019	38.4	44.8	86%	20.8	44.8	47%
2020	37.8	44.8	84%	19.7	44.8	44%
2021	42.8	44.8	96%	23.3	44.8	52%
2022	39.9	44.8	89%	21.5	44.8	48%
2023	37.3	44.8	83%	19.7	44.8	44%
Min	34.5	44.8	**77%**	19.1	44.8	**43%**
Max	42.8		**96%**	23.3		**52%**

Year	Rochester Substation Load (MW)	Rochester Substation Nameplate Capacity (MVA)	Rochester Substation Load % of Capacity	Tasker Farm Substation Load (MW)	Tasker Farm Substation Nameplate Capacity (MVA)	Tasker Farm Substation Load % of Capacity
2014	60.1	89.6	67%	12.7	44.8	28%
2015	57.4	89.6	64%	28.5	44.8	64%
2016	61.2	89.6	68%	30.9	44.8	69%
2017	52.6	89.6	59%	26.1	44.8	58%
2018	58.5	89.6	65%	28.6	44.8	64%
2019	59.5	89.6	66%	27.5	44.8	61%
2020	59.9	89.6	67%	32.4	44.8	72%
2021	61.5	89.6	69%	31.0	44.8	69%
2022	60.9	89.6	68%	31.6	44.8	71%
2023	58.4	89.6	65%	28.5	44.8	64%
Min	52.6	89.6	**59%**	12.7	44.8	**28%**
Max	61.5		**69%**	32.4		**72%**

Year	Timber Swamp Substation Load (MW)	Timber Swamp Substation Nameplate Capacity (MVA)	Timber Swamp Substation Load % of Capacity
2014	104.1	280.0	37%
2015	107.0	280.0	38%
2016	103.5	280.0	37%
2017	92.4	280.0	33%
2018	97.4	280.0	35%
2019	96.0	280.0	34%
2020	102.6	280.0	37%
2021	106.2	280.0	38%
2022	97.2	280.0	35%
2023	80.0	280.0	29%
Min	80.0	280.0	**29%**
Max	107.0		**38%**

8.2.3. Northern Region

	Ashland Substation			Beebe River Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	34.0	44.8	76%	19.4	44.8	43%
2015	31.2	44.8	70%	16.3	44.8	36%
2016	35.3	44.8	79%	17.7	44.8	39%
2017	26.9	44.8	60%	15.3	44.8	34%
2018	33.5	44.8	75%	17.1	44.8	38%
2019	32.2	44.8	72%	17.5	44.8	39%
2020	36.1	44.8	81%	20.1	44.8	45%
2021	32.8	44.8	73%	18.9	44.8	42%
2022	36.1	44.8	81%	23.3	44.8	52%
2023	31.5	44.8	70%	19.1	44.8	43%
Min	26.9	44.8	**60%**	15.3	44.8	**34%**
Max	36.1		**81%**	23.3		**52%**

	Berlin (Eastside) Substation			Laconia Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	15.3	35.0	44%	58.6	89.6	65%
2015	15.6	35.0	44%	55.7	89.6	62%
2016	17.5	35.0	50%	61.3	89.6	68%
2017	14.6	35.0	42%	51.3	89.6	57%
2018	18.3	35.0	52%	59.0	89.6	66%
2019	18.1	35.0	52%	59.6	89.6	67%
2020	16.6	35.0	48%	62.4	89.6	70%
2021	16.0	35.0	46%	61.1	89.6	68%
2022	16.4	64.8	25%	63.9	89.6	71%
2023	14.6	64.8	23%	55.4	89.6	62%
Min	14.6	64.8	**23%**	51.3	89.6	**57%**
Max	18.3		**28%**	63.9		**71%**

	Lost Nation Substation			**North Woodstock Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	9.9	28.0	35%	8.6	44.8	19%
2015	7.7	28.0	27%	8.2	44.8	18%
2016	8.2	28.0	29%	8.9	44.8	20%
2017	8.5	28.0	30%	7.2	44.8	16%
2018	10.4	28.0	37%	8.5	44.8	19%
2019	9.5	72.8	13%	9.4	44.8	21%
2020	10.5	72.8	14%	9.2	44.8	20%
2021	10.2	72.8	14%	9.1	44.8	20%
2022	10.6	72.8	15%	9.3	44.8	21%
2023	10.6	72.8	15%	7.9	44.8	18%
Min	7.7	72.8	**11%**	7.2	44.8	**16%**
Max	10.6		**15%**	9.4		**21%**

	Pemigewasset Substation			**Saco Valley Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	22.0	20.0	110%	19.9	44.8	44%
2015	20.9	20.0	104%	17.2	44.8	38%
2016	22.7	20.0	113%	18.6	44.8	42%
2017	19.7	20.0	99%	16.7	44.8	37%
2018	21.5	20.0	107%	18.7	44.8	42%
2019	21.5	20.0	107%	19.5	44.8	43%
2020	24.6	20.0	123%	19.9	44.8	44%
2021	23.0	62.5	37%	18.6	44.8	42%
2022	23.9	62.5	38%	18.6	44.8	41%
2023	21.5	62.5	34%	17.3	44.8	39%
Min	19.7	62.5	**32%**	16.7	44.8	**37%**
Max	24.6		**39%**	19.9		**44%**

	Webster Substation			White Lake Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	34.2	52.0	66%	42.4	56.0	76%
2015	32.5	52.0	63%	39.1	56.0	70%
2016	36.7	52.0	71%	43.7	56.0	78%
2017	33.1	52.0	64%	33.5	56.0	60%
2018	38.8	89.6	43%	40.7	56.0	73%
2019	36.6	89.6	41%	43.5	56.0	78%
2020	38.0	89.6	42%	47.6	56.0	85%
2021	36.9	89.6	41%	47.3	56.0	85%
2022	35.8	89.6	40%	50.1	56.0	89%
2023	36.1	89.6	40%	42.0	56.0	75%
Min	32.5	89.6	**36%**	33.5	56.0	**60%**
Max	38.8		**43%**	50.1		**89%**

	Whitefield Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	20.2	44.8	45%
2015	17.8	44.8	40%
2016	22.0	44.8	49%
2017	18.2	44.8	41%
2018	20.5	44.8	46%
2019	19.9	44.8	44%
2020	20.2	44.8	45%
2021	21.8	44.8	49%
2022	22.3	44.8	50%
2023	19.5	44.8	43%
Min	17.8	44.8	**40%**
Max	22.3		**50%**

8.2.4. Southern Region

	Amherst Substation			Bridge Street Substation (4.16 kV)		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	98.6	280.0	35%	7.5	10.5	71%
2015	97.9	280.0	35%	6.4	10.5	61%
2016	104.2	280.0	37%	6.6	10.5	63%
2017	96.5	280.0	34%	6.2	10.5	59%
2018	103.8	280.0	37%	7.4	10.5	70%
2019	101.3	280.0	36%	7.3	10.5	69%
2020	102.6	280.0	37%	7.2	10.5	69%
2021	106.1	280.0	38%	7.9	10.5	75%
2022	106.3	280.0	38%	7.5	10.5	71%
2023	97.3	280.0	35%	6.7	10.5	64%
Min	96.5	280.0	**34%**	6.2	10.5	**59%**
Max	106.3		**38%**	7.9		**75%**

	Bridge Street Substation (34.5 kV)			Chester Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	55.2	89.6	62%	35.5	89.6	40%
2015	51.1	89.6	57%	38.0	89.6	42%
2016	55.8	89.6	62%	38.2	89.6	43%
2017	46.7	89.6	52%	37.4	89.6	42%
2018	52.8	89.6	59%	41.7	89.6	47%
2019	52.3	89.6	58%	38.2	89.6	43%
2020	51.5	89.6	57%	44.3	89.6	49%
2021	55.5	89.6	62%	43.7	89.6	49%
2022	56.8	89.6	63%	41.8	89.6	47%
2023	50.9	89.6	57%	40.0	89.6	45%
Min	46.7	89.6	**52%**	35.5	89.6	**40%**
Max	56.8		**63%**	44.3		**49%**

	Hudson Substation			**Kingston Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	43.6	89.6	49%	11.8	44.8	26%
2015	39.1	89.6	44%	12.0	44.8	27%
2016	43.1	89.6	48%	13.0	44.8	29%
2017	39.3	89.6	44%	11.9	44.8	27%
2018	41.4	89.6	46%	12.7	44.8	28%
2019	41.1	89.6	46%	12.7	44.8	28%
2020	42.5	89.6	47%	13.6	44.8	30%
2021	44.4	89.6	50%	13.9	44.8	31%
2022	47.2	89.6	53%	13.4	44.8	30%
2023	47.2	89.6	53%	12.5	44.8	28%
Min	39.1	89.6	**44%**	11.8	44.8	**26%**
Max	47.2		**53%**	13.9		**31%**

	Lawrence Road Substation			**Long Hill Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	43.6	140.0	31%	62.6	89.6	70%
2015	42.8	140.0	31%	64.2	89.6	72%
2016	41.6	140.0	30%	66.4	89.6	74%
2017	42.2	140.0	30%	63.7	89.6	71%
2018	44.0	140.0	31%	67.0	89.6	75%
2019	44.0	140.0	31%	64.3	89.6	72%
2020	45.4	140.0	32%	66.8	89.6	75%
2021	46.9	140.0	34%	63.9	89.6	71%
2022	45.3	140.0	32%	61.8	89.6	69%
2023	42.2	140.0	30%	59.0	89.6	66%
Min	41.6	140.0	**30%**	59.0	89.6	**66%**
Max	46.9		**34%**	67.0		**75%**

	Mammoth Road Substation			Scobie Pond Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	41.6	89.6	46%	28.9	60.0	48%
2015	42.4	89.6	47%	27.7	60.0	46%
2016	44.7	89.6	50%	30.9	60.0	51%
2017	43.3	89.6	48%	28.7	60.0	48%
2018	46.3	89.6	52%	31.1	60.0	52%
2019	45.3	89.6	51%	29.6	60.0	49%
2020	47.9	89.6	53%	32.2	60.0	54%
2021	48.9	89.6	55%	31.9	60.0	53%
2022	48.7	89.6	54%	31.6	60.0	53%
2023	44.9	89.6	50%	30.1	60.0	50%
Min	41.6	89.6	**46%**	27.7	60.0	**46%**
Max	48.9		**55%**	32.2		**54%**

	South Milford Substation			Thornton Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	37.8	44.8	84%	22.3	44.8	50%
2015	38.2	44.8	85%	20.1	44.8	45%
2016	39.7	44.8	89%	19.1	44.8	43%
2017	38.7	44.8	86%	17.9	44.8	40%
2018	43.9	44.8	98%	17.4	44.8	39%
2019	41.1	44.8	92%	16.2	44.8	36%
2020	44.6	44.8	100%	17.3	44.8	39%
2021	46.1	44.8	103%	17.9	44.8	40%
2022	43.8	44.8	98%	17.3	44.8	39%
2023	41.9	44.8	94%	17.1	44.8	38%
Min	37.8	44.8	**84%**	16.2	44.8	**36%**
Max	46.1		**103%**	22.3		**50%**

8.2.5. Western Region

	Chestnut Hill Substation			**Emerald Street (Keene) Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	13.5	25.0	54%	35.2	92.2	38%
2015	14.5	25.0	58%	33.2	92.2	36%
2016	15.1	25.0	60%	34.7	92.2	38%
2017	13.8	25.0	55%	31.4	92.2	34%
2018	15.7	25.0	63%	35.0	92.2	38%
2019	14.6	25.0	58%	32.9	92.2	36%
2020	16.7	25.0	67%	31.7	92.2	34%
2021	16.3	25.0	65%	33.3	82.4	40%
2022	16.0	25.0	64%	33.2	82.4	40%
2023	15.2	25.0	61%	32.9	82.4	40%
Min	13.5	25.0	**54%**	31.4	82.4	**38%**
Max	16.7		**67%**	35.2		**43%**

	Jackman Substation			**Monadnock Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	32.6	72.8	45%	34.3	48.0	71%
2015	32.7	72.8	45%	33.1	48.0	69%
2016	32.6	72.8	45%	39.1	48.0	81%
2017	29.3	72.8	40%	29.2	48.0	61%
2018	32.9	72.8	45%	36.8	48.0	77%
2019	31.5	72.8	43%	33.7	48.0	70%
2020	34.7	72.8	48%	34.8	48.0	73%
2021	35.4	72.8	49%	36.0	48.0	75%
2022	37.1	72.8	51%	37.3	48.0	78%
2023	32.5	72.8	45%	36.9	48.0	77%
Min	29.3	72.8	**40%**	29.2	48.0	**61%**
Max	37.1		**51%**	39.1		**81%**

	North Keene Substation			**North Road Substation**		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014				35.6	89.6	40%
2015				32.5	89.6	36%
2016				38.4	89.6	43%
2017	16.4	30.0	55%	34.3	89.6	38%
2018	19.1	30.0	64%	38.8	89.6	43%
2019	18.1	30.0	60%	37.2	89.6	42%
2020	19.1	30.0	64%	40.6	89.6	45%
2021	18.9	30.0	63%	41.2	89.6	46%
2022	18.1	30.0	60%	40.7	89.6	45%
2023	17.9	30.0	60%	38.2	89.6	43%
Min	16.4	30.0	**55%**	32.5	89.6	**36%**
Max	19.1		**64%**	41.2		**46%**

	Swanzey Substation		
Year	Load (MW)	Nameplate Capacity (MVA)	Load % of Capacity
2014	6.5	25.0	26%
2015	6.7	25.0	27%
2016	6.4	25.0	26%
2017	6.0	25.0	24%
2018	7.1	25.0	29%
2019	6.6	25.0	26%
2020	7.3	25.0	29%
2021	7.4	25.0	30%
2022	7.3	25.0	29%
2023	6.9	25.0	27%
Min	6.0	25.0	**24%**
Max	7.4		**30%**

8.3. Table of Figures

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