SUMMARY NARRATIVE

STATE OF THE DISTRIBUTION SYSTEM

The Connecticut Light & Power Company d/b/a Eversource Energy

July 14, 2026

Executive Summary

This document is designed to provide a basic summary overview of the current state of the electric distribution system owned and operated by The Connecticut Light & Power Company d/b/a Eversource Energy ("Eversource" or the "Company"). This summary report is presented in a non-technical manner to describe the system configuration; discuss how the system performs and why it faces significant challenges; and to highlight on the investments that Eversource is making to address those challenges.

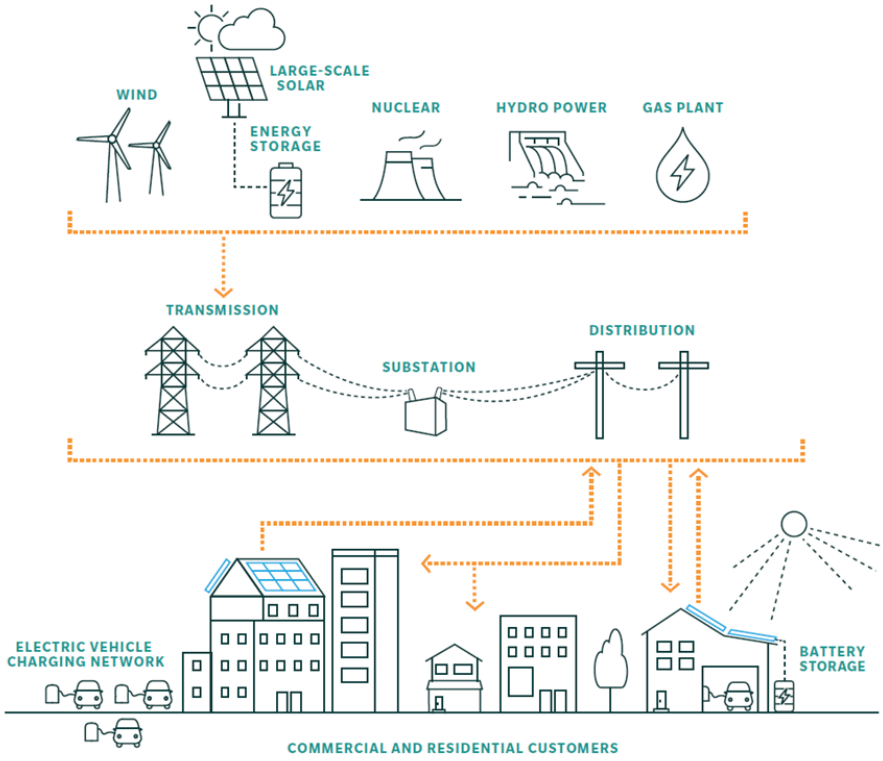
System Characteristic	Current Value	Notes
Total Customer Accounts	~1.3 million	Residential + C&I
Total Circuit Miles	~23,593 miles	All construction types
Overhead Circuit Miles	~16,640 miles (71%)	Bare wire + covered wire
Underground Circuit Miles	~6,953 miles (29%)	Includes network
Bare-Wire Miles	~7,500 miles (47%)	
Covered Wire Miles	~9,140 miles (53%)	Includes aerial &spacer
Wood Poles - Eversource	413,844	56% of 734,952
Wood Poles - Telephone	321,109	44% of 734,952
Number of poles at current standard (Class 2+)	179,419 (24%)	
Number of poles below current standard (Class 3 or lower)	561,179 (76%)	
Total Reclosing Devices	6,064	Reclosers + trip savers
Automatic Tie Reclosers	~1,000	
Number of Bulk Substations	99	Substation supplied from bulk transmission

System Characteristic	Current Value	Notes
Number of Distribution Substations (Non-Bulk)	57	Substation supplied from distribution lines
Substation Transformers	314	Total in bulk and non-bulk substations
Substation Circuit Breakers	1,702	Total in bulk and non-bulk substations
Number of Feeders/Circuits	995	Total supplied from bulk and non-bulk substations

1. Understanding the Eversource Electric Distribution System

The basic architecture of the electric power grid has not changed much since its inception over a century ago. Most power is still produced by central generating stations, whether fueled by natural gas, hydropower, nuclear, or other resources, connected by high-voltage networked transmission lines. The electric distribution system is the "last mile" of the power grid, comprised of substations, lines, poles, transformers, protection devices, switches and sensors that take high-voltage electricity from the transmission system and deliver it safely and reliably directly to homes and businesses at usable or service voltages. The electric grid functions like a local road network with the transmission system as the interstate highway and the distribution system as every local or neighborhood street that connects from the interstate highway to a customer's driveway.

The diagram below shows an overview of the electric power system and the function of distribution infrastructure within that framework.



Even though the basic architecture of today's electric grid is fundamentally the same, the mission and challenges facing modern power systems and the impact of those challenges on customers have significantly evolved over the past several decades. For example, although most generation resources continue to operate as central power plants feeding into the transmission network, the significant retirement of traditional generation sources (like coal and gas plants) coupled with the expansion of inverter-based resources ("IBR"), including growth in offshore wind, transmission-connected large-scale solar farms and distributed energy resources (DER) like solar photovoltaic (PV) and battery energy storage systems (BESS) is fundamentally changing the requirements for power system operation and control. As the figure above shows, the distribution system has evolved to accommodate these new generation sources, as well as new end-use technologies such as electric vehicles (EV) and local battery energy storage in customer residences and businesses. These modern-day resources and end-uses present unique challenges to how the system is operated and controlled, and

drive investments in infrastructure, equipment and technology on the distribution system.

Serving as the interface between the transmission system and customers, the distribution system is the backbone of a reliable Electric Power System (EPS). An effectively planned and securely operated distribution grid is therefore critical as customers transition to an electrified future, with Eversource charged with a core mission of providing essential safe, reliable and resilient electric service to all customers.

1.1 How the System Functions

The system moves electric power from the source to loads in several steps:

- Bulk distribution substations receive power from the high-voltage transmission grid and step it down via substation transformers to distribution medium voltage levels. These are the starting points of the local delivery system.
- Distribution feeders (also called circuits), comprised of poles and wires, move power radially at medium voltage levels from the substation out to towns, neighborhoods and individual customers. Along some feeders, *non-bulk* distribution substations might step voltage down from one medium voltage level (e.g., 23 kV) to another (e.g., 5 kV). A single feeder can serve anywhere from a few hundred to thousands of customers, often extending for many miles from the substation to our customers' homes and businesses.
- Service transformers receive power from distribution feeders and step it down to service voltage levels, which is then routed by secondary lines (e.g., 120/240V) to customers' homes and businesses. A single service transformer can serve anywhere from 1 to 10 or more customers, typically located in close proximity to the transformer.

Within this complex power delivery system, bulk distribution substations are key components, essential to meeting consumer demand for energy, and supporting 21st century economies. 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 Connecticut customers. The figure below shows a typical bulk distribution substation with incoming high voltage transmission lines (e.g., 115 kV), terminating at high voltage buses, power transformers that step voltage down to distribution levels (e.g. 13.2 kV, 13.8 kV, or 23 kV) and outgoing distribution feeders routing power to towns, neighborhoods and customers.

Eversource's distribution system includes bulk substations in 99 locations; almost 1,000 distribution feeders comprising almost 24,000 circuit miles; and over 265,000 service transformers serving approximately 1.3 million customer accounts across Connecticut.



1.2 How the System is Constructed: Overhead vs. Underground

Distribution lines are constructed in two different ways which each has distinct performance characteristics:

Construction Type	How It Works	Tradeoffs
Overhead (O/H) (bare or covered wire)	Wires strung on wood poles, exposed to the environment	Lower cost to build and repair; most vulnerable to weather and trees, especially bare wire
Underground (U/G) cable	Insulated cables directly buried or in conduit and structures below ground	Protected from weather and trees; outages are less frequent but far longer to repair when they occur

The Connecticut distribution system is approximately **71 percent** overhead and **29 percent** underground, including underground network construction. Notably, a

significant amount of overhead construction, about 7,500 miles or 47 percent, is still bare wire, with no protection against tree contact.

1.3 How the System is Designed: Radial vs. Looped vs. Networked

Distribution systems are typically designed in three different configurations, each having distinct cost and operational characteristics:

Construction Type	How It Works	Tradeoffs
Radial Design	Designed and operated with one path for power flow from the source to the load	Lower cost and simple to operate, but outage results in interruptions for downstream customers
Loop Schemes	Includes a (normally open) tie point between feeders to provide an alternate source of power to the load	Higher cost and complexity, but Improves reliability by allowing customers downstream of an outage to be picked up by an alternate feed
Meshed Networks	Interconnected or meshed design, providing multiple redundant supply paths from the source to the load.	Very high reliability; complex and expensive to operate and maintain; used in UG secondary networks to supply dense urban areas Hartford, Waterbury, Norwalk, Stamford

Most distribution systems are designed and operated in a radial configuration. In Connecticut, most of the radial O/H system is looped designed with smart switches installed at tie points between feeders and all along the feeders to allow the system to be reconfigured following a fault – failure of conductor or equipment that requires de-energization by protection equipment. Most new residential construction is designed using U/G cables, and are looped when serving 26 or more lots. There are a relatively small number of U/G networks in a few urban central business districts. For these U/G secondary networks, the source is the network transformer that can be operate in parallel to supply customers more reliably.

An outage event is a failure of any component or equipment on the system that interrupts the path of power flow (directly or indirectly) from the source to the load. This could be, for example, a tree that falls across a line and breaks the conductor,

directly interrupting power to customers fed from the line section. This event could also require the protection system to operate and de-energize customers fed from other sections for safety reasons, indirectly creating interruptions. This and many other types of equipment failures typically lead to customer interruptions, especially on radial distribution lines. However, not all outage events interrupt customers.

Because there are multiple paths for power flow, U/G networks and bulk substations can sustain failure or outage of a single component without interrupting customers (N-1 design). Since radial distribution lines are not designed for N-1 operation, reliability is ensured by using sectionalizing and protection devices to (1) limit the number of customers impacted by an outage to a single zone; and (2) reconfiguring the system to pick up as many customers as possible in other zones that do not have an outage event. Most sectionalizing devices are designed to automatically reconfigure the system to quickly reduce the impact of outage events on customers. In this way, distribution automation helps to compensate for some of the intrinsic shortcomings of bare overhead, radial distribution construction. Loop schemes in Connecticut employ this fundamental principle to ensure that during a fault, most customers (except those in the faulted zone) experience no more than a momentary interruption.

2. Eversource's Unique Operating Environment in Connecticut

To understand why the Connecticut system faces the challenges it does, it is important to understand the environment in which it operates. Connecticut is like few other states in the country in one critical respect – it is simultaneously one of the most densely populated and one of the most canopy covered states in the nation.

Connecticut Forest & Population Facts	
Forest Cover (land area)	75-78 percent
Total Tree Canopy (including urban)	~75 percent
National Rank – Forest Cover	13th in the Nation
National Rank – Population Density	4th in the Nation
Forest Trees > 61 years old	~85 percent

These statistics indicate that Eversource's overhead wires, 47 percent of which are bare copper wire, run through and under some of the most mature, densely forested corridors of any utility in the United States. Approximately 85 percent of the state's trees are over 61 years old, tall and heavily canopied, with many growing directly into or over utility rights-of-way.

Connecticut's forests are also structurally pre-disposed to storm damage. The dominant forest types of oak-hickory and northern hardwoods grow tall and comparatively slender under crowded canopy conditions, making these trees particularly susceptible to wind throw and branch failure. Trees along right-of-way boundaries grow asymmetrically toward open space, developing lopsided crowns. When storms arrive, these are the trees that fall first and most often — directly onto distribution lines. The vegetation operating environment combined with the high proportion of bare overhead distribution circuits, is at the core of any real or perceived reliability and resiliency performance issues on the Connecticut distribution system.

3. How the System Currently Performs

System performance is measured using industry-standard reliability indices. Understanding these metrics is important for putting Eversource's system performance into context.

3.1 Reliability Metrics Explained

Metric	What It Measures
SAIDI (System Average Interruption Duration Index)	Average minutes of interruption per customer per year
SAIFI (System Average Interruption Frequency Index)	Average number of interruptions per customer per year
CAIDI (Customer Average Interruption Duration Index)	Average duration of each interruption (minutes)
CMI (Customer Minutes Interrupted)	Total customer-minutes of interruption system-wide
CI (Customer Interruptions)	Total number of customer interruptions system-wide

3.2 Blue Sky vs. Storm Performance

One of the most important aspects of understanding system performance is the distinction between normal operating days (called “blue-sky” days) and storm-active days. The data tells two very different stories depending on which type of day is examined.

KEY FINDING: From 2021–2025, approximately 75 percent of total system CMI occurred on storm-active days, which are days with 100 or more outage events. These days represent approximately 12 percent of calendar days. Vegetation exposure drives the majority of the customer impact.

Day Type	% of Total Customer-Minutes of Interruption (CMI)
Storm-Active Days (≥100 outage events/day)	~74–76 percent
Blue Sky Days (<100 outage events/day)	~24–26 percent

3.3 Storm Activity: How Often Is the System Under Stress?

The table below shows the annual breakdown of storm days, minor storm days and blue-sky days for 2022–2025:

Year	Major Storm	Minor Storm	Total Storm	Blue Sky
2022	3	27	30	335
2023	3	29	32	333
2024	3	38	41	325
2025	8	37	45	320

These storm days have a direct and measurable impact on customers. The following tables show how customers interrupted ("CI") and customer-minutes of interruption ("CMI") are distributed across weather condition types each year:

Customer Interrupted by Weather Condition:

Year	Major Storm (%)	Minor Storm (%)	Blue Sky (%)	Total CI (Customers)
2022	24.6%	21.4%	54.0%	1,106,554
2023	21.9%	31.0%	47.1%	1,068,347
2024	12.6%	42.0%	45.3%	1,099,224
2025	34.0%	21.9%	44.1%	1,231,779

Customer-Minutes of Interruption (CMI) by Weather Condition:

Year	Major Storm (%)	Minor Storm (%)	Blue Sky (%)	Total CMI (Minutes)
2022	58.2%	17.7%	24.1%	241,847,530
2023	57.3%	21.6%	21.1%	237,711,456
2024	34.9%	40.6%	24.5%	200,796,611
2025	61.3%	17.0%	21.7%	280,183,635

3.4 What Causes Outages?

The root causes of outages differ significantly between storm-active and blue-sky days. This is critical for investment prioritization.

Cause	Major Storm (%)	Minor Storm (%)	Blue Sky (%)	Total Events
Tree / Vegetation (Tree, Trim Zone, Vines)	93.8%	77.9%	45.0%	54,060
EQUP-Equip Failure	1.9%	6.6%	19.7%	10,515
ANIM-Animal/Birds	0.5%	3.0%	19.7%	9,362
VHCL-Veh Accident	0.3%	1.1%	5.9%	2,898
LTNG-Lightning	0.8%	6.9%	1.8%	2,679
PTNF-Patrolled Nothing Found	1.3%	1.5%	2.5%	1,674
OVLD-Overload	0.2%	1.8%	1.9%	1,318

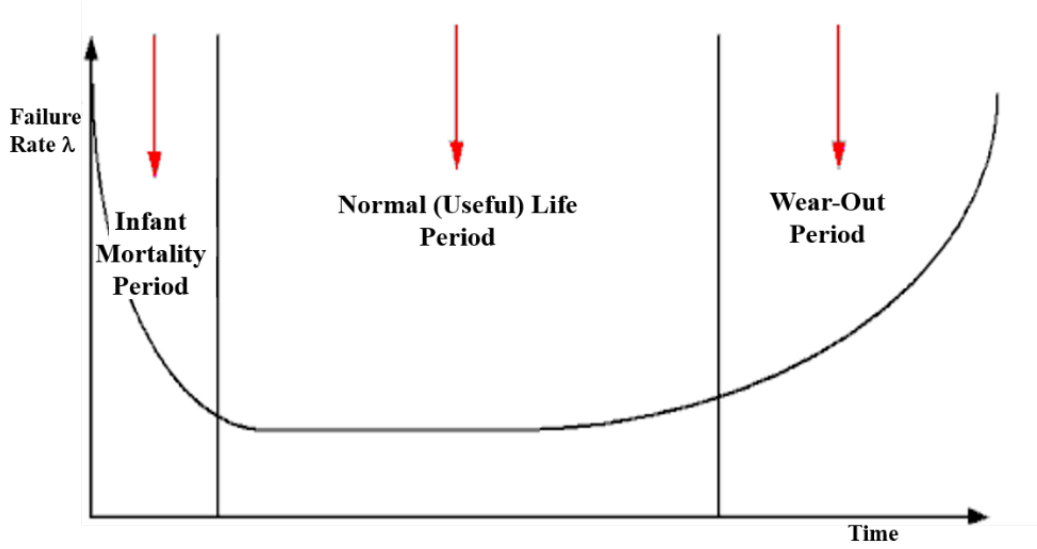
4. Legacy Infrastructure: Where the System Came from and Why It Matters

Connecticut's distribution system was designed and built during an era when the performance standards, weather patterns, and tree canopy conditions were significantly different from today.

4.1 The Aging Infrastructure Issue

As assets age beyond their design life, the assets enter the wear-out period (as shown in the figure below), where failure rates rise sharply due to insulation breakdown, corrosion, mechanical wear, and obsolete components. In a distribution system with a large share of assets in this "wear-out" phase, customers would experience more frequent and severe

outages, and the cost to improve reliability is significantly higher. Proactive renewal and targeted replacement strategies are therefore critical to keep the overall population of assets in the normal (useful life) middle phase of the bathtub curve and maintain reliability.



A transformer is a static, passive device used to increase (step-up) or decrease (step-down) the magnitude of electrical potential (voltage) within a given Alternating Current (AC) electrical system. A transformer contains a ferrite (high magnetic permeability with low electrical conductivity) core with electrically conducting coils (also referred to as windings) wrapped around opposite sides of the transformer core. An input voltage source is connected to one of the coils (the primary side of the transformer), and an output voltage is produced proportionally to the ratio of windings on the coil connected on the opposite side of the core (secondary side).

In Connecticut, the distribution substation transformer fleet consists of bulk transformers and distribution (non-bulk) transformers. Bulk transformers are installed at bulk distribution substations that are directly supplied from the transmission system (typically 115 kV) and step voltage down to distribution levels (typically 27.6 kV, 23 kV, 13 kV, or 5 kV). Distribution transformers are installed at distribution substations supplied from other distribution systems (e.g., 27.6 kV) and step voltages down to supply customers.

Substation transformers are designed for an expected life of 40 years. The current fleet average is 43 years, with 56 percent of units operating beyond design life, materially increasing failure and outage risk.

Circuit breakers are an essential part of the electric system because they help protect equipment, support safe operation, and allow power to be shut off when needed. They are designed to stop the flow of electricity during normal switching operations and during fault conditions, helping reduce the risk of equipment damage and broader service disruptions.

When a circuit breaker opens, the separation of its contacts creates an electrical arc within the insulating material inside the breaker. The strength of this arc depends on the amount of current being interrupted. As the contacts move farther apart, the breaker is designed to stretch and extinguish the arc so that the flow of electricity stops safely. Successful operation depends on preventing the arc from forming again after it has been extinguished.

Life expectancy of circuit breakers is typically 40 years. There are 1,702 in-service circuit breakers on the Connecticut distribution system. Approximately 356 circuit breakers, or 20 percent, are over 40 years old.

Reclosers are automated devices that help protect the electric system by temporarily interrupting power when they detect an abnormal condition and then restoring service after a short delay if conditions return to normal. They operate using a programmed sequence of opening and reclosing, followed by either a reset period, remaining closed, or locking out if the problem continues. In general, the industry considers a recloser to have a life expectancy of about 10,000 full-load operations, which typically corresponds to roughly 20 to 30 years of service, depending on operating conditions and maintenance history.

There are currently 87 oil-filled substation reclosers in service. Thirty-eight (38) of these or 44 percent are at the end of their useful service life.

Across Connecticut there are several small, aging distribution 4.16 kV and 4.8 kV (hereafter referred to as "5 kV") substations with an average age of 60+ years that, if not eliminated, will require significant upgrades and equipment replacement to remain in service. Fourteen of these substations are "islanded," meaning that all or most of the load cannot be picked up by alternate sources in the event of an equipment failure within the substation. Converting these areas to standard higher voltages such as 13.2 kV, 13.8 kV or 23 kV will

improve reliability for customers and provide the means to restore customers via an alternate source for both non-storm and storm events.

A significant portion of legacy #2, #4, and #6 bare copper conductor has exceeded expected service life—typically over 50 years—and has experienced significant mechanical degradation, including embrittlement and reduced tensile strength. These aging conductors exhibit elevated failure rates under normal loading and environmental stress conditions, contributing to sustained customer interruptions.

Defective wooden poles are identified for replacement during the annual pole inspection process. These poles must be replaced as they can no longer remain in service, due to loss of structural strength, decay, insect infestation and physical damage resulting in a risk to public safety and system reliability. The expected life of a utility pole is 40-45 years with Connecticut poles averaging 47 years. Wooden poles located in right-of-ways (ROW) particularly show visible signs of degradation on both poles and crossarms as well as signs of wildlife damage. The majority of these poles are past their service life, with the average age being over 50 years. Without addressing these asset conditions, reliability will be at continued risk and susceptible to failures causing extended outages to customers.

A significant portion of legacy #2, #4, and #6 bare copper conductor has exceeded expected service life—typically over 50 years—and has experienced significant mechanical degradation, including embrittlement and reduced tensile strength. These aging conductors exhibit elevated failure rates under normal loading and environmental stress conditions, contributing to sustained customer interruptions. Most underground structures - vault/manhole/handhole/service box - in Connecticut were installed in the mid-1900s. A total of 74 of 121 structures, reviewed by civil engineering, were found to be deficient and in need of capital repairs (2021 - 2025).

Industry-wide, there is consensus that much of the original XLP and HMP-insulated primary direct-buried (DB) cable has not achieved engineered life expectancy. Premature cable failures have degraded the reliability for the Company's customers served by these cables, most of which were installed in the ground without a conduit system in the 1970s and 1980s.

Most underground structures - vault/manhole/handhole/service box - in Connecticut were installed 1920s through 1970s. 74 of 121 structures, reviewed by civil engineering, were found to be deficient and in need of capital repairs (2021 - 2025).

4.2 The Substation Capacity Risk

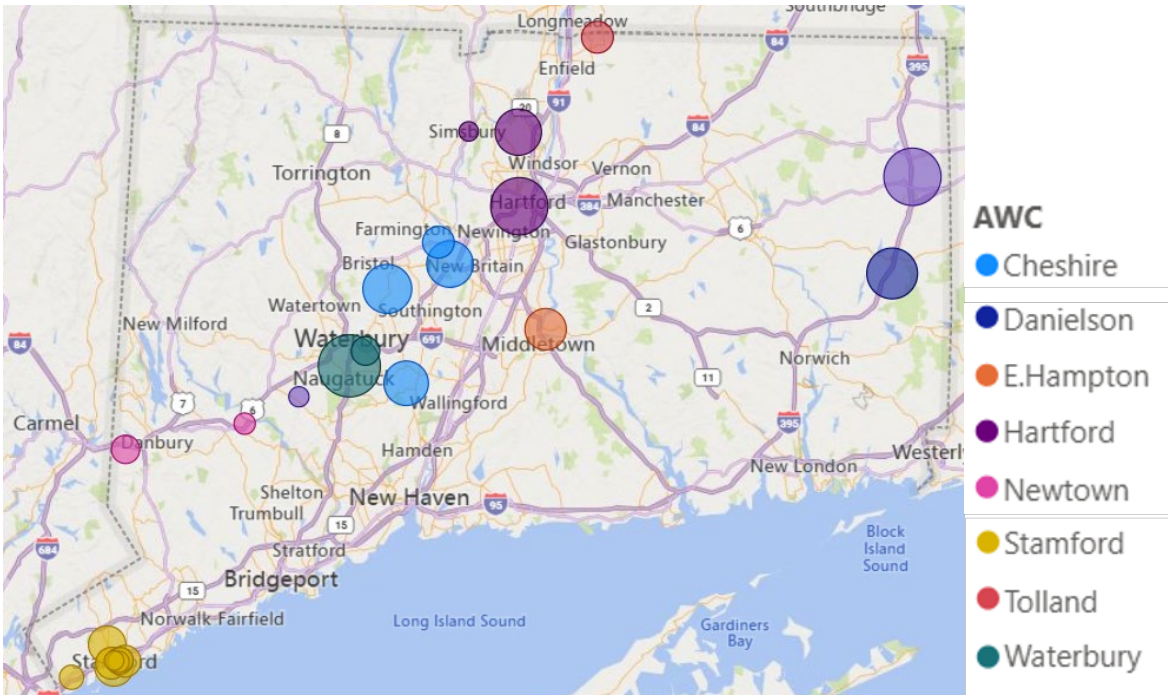
Across Connecticut there are 99 bulk distribution substations serving approximately 1.3 million customers with an aggregate peak demand in excess of 5 GW. Over the past decade, load at the state-wide level has had a compound annual growth rate (CAGR) of 0.5 percent. The relatively low CAGR over the past decade is the result of annually increasing deployment of behind-the-meter solar on commercial and residential rooftops. This has resulted in the peak shifting from 5:00 PM in 2015 to 7:00 PM in 2025. In addition, the State's Energy Efficiency Program has had success in reducing demand. However, as the peak settles into evening hours, future reductions are significantly diminished (due to the nature of solar production) and the peak reduction impact per installed MW of solar drops towards zero.

Despite this, within each of the three planning regions, there are load pockets, comprised of one or several bulk substation service territories, where load growth is significantly greater than the state average, driven by hyper-local factors, such as new large development (step loads), including large commercial developments. The bulk substations in these load pockets enable safe, reliable service by providing capacity for growth and sufficient operational flexibility to ensure that customers can remain energized during emergencies, such as failure of a substation transformer, or planned outage conditions which can take weeks to months to repair or replace.

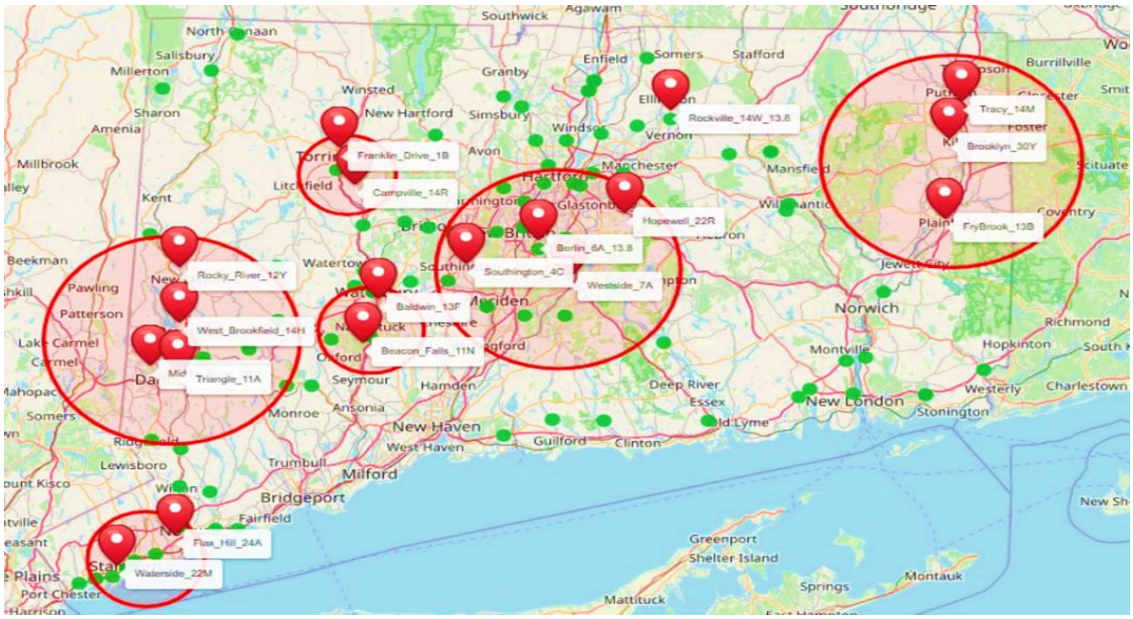
Normally, substations are planned and operated with spare capacity to provide this operational flexibility. However, as demand increases in local areas, due to residential end uses, commercial activity, electrification and other drivers, this spare capacity diminishes to the point where the system becomes operationally static and thermally constrained, and load can no longer be shifted between transformers or substations during an emergency. The two figures below show: (1) the location and size of large commercial developments across Connecticut in the next five years; and (2) areas across the state where the substations in the load pockets are or will be at thermal capacity limits within ten years.

Absent upgrades or mitigation measures, approximately 25 percent of Eversource substations are projected to reach or exceed their capacity limits by 2035, placing 30,000 to 50,000 customers at risk of being dropped during emergency conditions. Because the development of a new bulk substation requires 5 – 7 years, these capacity constraints pose a significant long-term reliability risk to customers in these areas of the state.

Step Load Activity in Eversource Territory as of 2026



Areas of the System with Substations Capacity Constraints



4.3 The Sub-Standard Pole Problem

Wood utility poles are classified by strength and height using a national standard called pole class. Class 1 is the strongest and tallest; Class 5 or higher (numerically) is the smallest. Eversource's current standard requires at a minimum a Class 2 pole for new installations, reflecting the need to support taller and stronger overhead configurations in today's storm and vegetation environment.

> 76 percent of wood poles on the Connecticut system, or 561,179 out of 740,598 poles, are Class 3 or smaller, below the Company's current standard. These poles are 3 to 4 classes weaker and shorter than what is required today to properly support elevated storm and vegetation contact loads.

Pole Class	Count
Class 2 or Higher (meets standard)	179,419
Class 3 or Lower (below standard)	561,179
Total Poles	740,598

This is not a minor gap. Three-quarters of the pole fleet was installed under older standards and cannot adequately support the loads that modern conductor configurations, storm forces, and vegetation contact generate. Replacing this pole fleet to current standards is a long-term program that requires systematic, risk-prioritized investment.

4.4 The Bare Wire Exposure

As noted earlier, approximately 47 percent of the overhead distribution system, roughly 7,500 miles, is still constructed with bare (uninsulated) wire. This wire has no protection against tree contact. When a branch or limb touches bare wire, it creates an immediate fault, which means at least a momentary interruption for all customers downstream.

In urban centers, the system uses underground and network construction. Historically, bare wire's lower cost was justified by then-prevailing weather patterns and customer expectations. That calculus has changed significantly as storms have intensified and forest canopy has matured and expanded.

4.5 The Underground and Network Challenge

Urban centers such as Hartford, Waterbury, Norwalk and Stamford are served primarily by underground cable and interconnected network systems. Although these systems are largely immune to weather and tree events, each system presents its own challenges:

- When underground cables fail, locating and repairing the fault takes much longer than an overhead repair, often resulting in outage durations of many hours to days.
- Paper-insulated lead-covered (PILC) cable, a legacy underground cable type, is approaching end of life in many locations. These older cables, which now have

higher failure rates, must be proactively replaced to prevent manhole events, manhole fires, and worker safety incidents as.

5. How Eversource Manages and Improves Bluesky System Performance

On most days without significant storm activity, system performance is driven by the equipment condition and capability, system design, maintenance and operational procedures that: (1) help to prevent outages; (2) limit the impact of outages when they do occur; and (3) quickly repair or reconfigure the system to restore customers after outage events. Eversource manages this complex task through a layered approach, with planning and engineering standards that govern how the system is designed, built and maintained; data-driven investment tools that identify and address the highest-risk assets proactively; field technologies that prevent temporary faults from becoming customer interruptions, and time-tested operational procedures to quickly restore customer service after a fault. This section describes each of those layers and how the layers work together to maintain safe, reliable service under normal operating conditions.

5.1 Planning and Engineering Standards for Proactive Investment Strategies

Eversource's planning and engineering standards work cohesively to ensure that sufficient capacity and operational flexibility exist from the substation level all the way down to distribution lines, to ensure safe, reliable service for all customers.

Load Forecasting Framework

The Company currently maintains two complementary forecasting processes:

- 10-Year Load Forecast, and
- Long-Term Demand Assessment, extending approximately 25 to 30 years into the future and commonly referred to as the Long-Term Demand Assessment.

Although these studies rely upon substantially the same data sources, analytical tools, and forecasting methodologies, they serve different planning purposes.

1. The 10-Year Load Forecast is the Company's operational planning forecast. It is used to identify future substation capacity deficiencies that require infrastructure

investment. Because major substation projects frequently require multiple years—and in some cases nearly a decade—to design, permit, and construct, this forecast provides system planners with sufficient lead time to initiate projects before capacity limitations are reached.

2. The Long-Term Demand Assessment is not used to trigger capital projects. Rather, it evaluates how long-term policy objectives, technology adoption, and electrification trends may influence future electric demand over the coming decades. When a project is initiated based upon the 10-Year Load Forecast, the Long-Term Demand Assessment is consulted to ensure that the selected infrastructure solution can either accommodate anticipated long-term growth or be readily expanded in the future.

For example, if the Company determines that a new substation requires two transformer banks to satisfy projected needs over the next decade, the station may nevertheless be designed with sufficient physical space, foundations, bus arrangements, and distribution line exits to accommodate a third transformer bank should future demand materialize. Designing facilities in this manner substantially reduces future expansion costs while preserving long-term system flexibility.

Long Forecasting Data and Analytics

The Company's forecasting methodology combines historical operating data, weather normalization, economic forecasting, distributed energy resource analysis, transportation electrification modeling, energy efficiency impacts, and large customer development projections to provide the most comprehensive picture of future load development.

- Historical System Load Analysis

  The forecasting process begins with an evaluation of the previous ten years of historical peak loading for each substation.

  Historical loading information is obtained directly from the Company's SCADA systems and operational historian databases. These data are processed through the Company's internally developed Gross Load Tool, which reconstructs the true underlying electrical demand, or gross load, served by each substation.

Rather than relying solely upon measured net load, the Gross Load Tool estimates the gross electrical demand that would have occurred absent behind-the-meter distributed energy resources such as rooftop solar generation. This distinction is critical because measured peak demand may vary substantially depending upon weather conditions, cloud cover, and solar production.

For example, one year's system peak may occur during clear skies with significant photovoltaic output, while another year's peak may occur during hot, humid, overcast conditions when solar production is substantially reduced. Simply comparing measured peak loads would therefore misrepresent the actual underlying customer demand. The Gross Load Tool removes this distortion by estimating the gross customer load independent of distributed generation output.

The Gross Load Tool also identifies and removes abnormal operating conditions resulting from switching operations, outages, storm events, or other temporary system configurations that could otherwise distort forecast development.

Using these analyses, the Company develops a representative "typical load year" for each substation, from which weather-normalized peak demand is established.

- Economic Trend Forecasting

  Historical load growth is combined with long-term economic projections obtained from Moody's Analytics. These economic forecasts provide projected regional economic growth over approximately a thirty-year planning horizon and serve as the baseline forecast for future electric demand.

  The Company subsequently applies a series of engineering adjustments to this baseline forecast to reflect anticipated changes in customer technologies, distributed energy resources, transportation electrification, energy efficiency, and known customer developments.

- Distributed Energy Resource Modeling

  The Company explicitly models the impact of distributed energy resources, particularly behind-the-meter solar photovoltaic systems.

The Company maintains detailed records identifying the location and characteristics of installed distributed generation throughout its service territory. In addition, the Company has assembled highly granular historical irradiance datasets spanning more than a decade. These datasets quantify the amount of solar radiation received at each substation location at fifteen-minute intervals.

These data enable the Company to statistically model expected solar production under varying weather conditions and determine the likelihood that periods of high gross electrical demand coincide with reduced photovoltaic generation.

Using these models, forecasted gross demand is reduced by expected solar production based upon the anticipated timing of system peaks. Importantly, this process also captures the temporal impacts of distributed generation, recognizing that increasing solar penetration may shift the timing of peak demand later into the evening hours.

Accordingly, the Company models not only the magnitude of future peak demand but also its expected timing using highly granular weather, irradiance, and temperature datasets.

- Electric Vehicle Forecasting

  Transportation electrification represents one of the most significant drivers of future electric demand as it directly impacts the currently prevailing summer peak.

  The Company employs both bottom-up adoption propensity models and top-down state electrification objectives to forecast electric vehicle adoption.

  To determine where charging demand will occur, the Company utilizes detailed commercially available mobility datasets that analyze anonymized GPS-based travel patterns. These datasets identify trip origins, destinations, dwell times, and travel behavior for light-duty, medium-duty, and heavy-duty vehicles. This approach recognizes that the location where a vehicle is purchased or registered may differ substantially from where it is regularly charged.

  Using these mobility models, the Company forecasts charging demand at the substation level, distinguishing between commercial areas that experience

significant daytime charging and residential areas where charging predominantly occurs during overnight hours.

The Company also incorporates coincidence and diversification factors into these forecasts. Rather than assuming all electric vehicles charge simultaneously, statistical diversity models estimate the probability that vehicles will charge concurrently, producing more realistic demand projections. These models also provide a foundation for evaluating future managed charging programs and other flexible load management strategies.

- Energy Efficiency and Large Customer Development

  Forecasts are further refined through adjustments reflecting anticipated impacts from state energy efficiency programs.

  The Company also incorporates known, large customer developments into its forecasts.

  To support this work, the Company utilizes commercial intelligence data provided by CoStar, which supplies detailed information regarding commercial building development, occupancy, and vacancies throughout the Company's service territory.

  These datasets are combined with interval metering information to validate projected customer loads against observed customer behavior. This enables the Company to develop highly detailed forecasts for significant commercial and industrial customer developments.

  Collectively, historical system analysis, economic forecasting, distributed energy resource modeling, electric vehicle forecasting, energy efficiency projections, and large customer analyses are integrated into the Company's substation-level forecasts and long-term demand assessments.

Substation Planning

At the bulk substation level, the Distribution System Planning Guide (DSPG) establishes criteria and guidelines for planning and design of bulk substations and distribution facilities

and sets forth the various criteria by which the capacity and reliability performance of the Company's supply systems are measured. To maintain adequate levels of reserve capacity and reliability, that meet or exceed customers' increased expectations, a foundational requirement is that bulk distribution substations be designed to sustain any single contingency (N-1) event with no loss of customer service.

This requirement ensures that failure of a substation component, which can take weeks to months to repair or replace, does not lead to prolonged customer interruptions. This is the bedrock of reliable system performance. The Company's distribution planning process begins with the forecast of demand at each bulk substation ten-years out, followed by detailed, data-driven analyses to identify capacity violations that impact customers. Lastly, solutions and proactive investments are collaboratively developed to meet the area capacity needs in a safe, reliable manner at the lowest possible cost. Planning and expanding the bulk distribution system in this manner provides a foundation for the reliable operation of the entire distribution system. When there is a lack of operational flexibility at the bulk substation level, load cannot be quickly shifted, either between transformers in the same substation or between neighboring substations during an emergency. The impact of these constraints will manifest as prolonged customer interruptions and a severe degradation in distribution reliability further down the system as measured by SAIDI and SAIFI.

Distribution Engineering

At the distribution line level, Engineering Standards and the Distribution System Engineering Manual (DSEM) establish construction methods, minimum asset specifications and operational procedures required to maintain safe and reliable service. These standards are not static and, rather, are updated regularly to reflect changes in industry, best practices, evolving weather patterns, customer expectations, and new technologies. The standards apply equally to planned capital work and to emergent field repairs, ensuring that every asset installed or replaced meets the current performance bar.

Beyond standards compliance, Eversource has developed a data-driven investment model that identifies underperforming zones based on their blue-sky reliability record over the prior five years and recommends the most cost-optimal solution from a portfolio of feasible options. Rather than applying a single measure uniformly across the system, this tool evaluates each zone against multiple interventions such as upgrading from bare to covered

wire, replacing aging equipment, or adding protective devices, and selects the option that delivers the greatest customer benefit per dollar invested.

Proactive replacement programs are a key output of this investment framework. A clear example is the ongoing replacement of paper-insulated lead-covered ("PILC") cables in the underground network systems serving Hartford, Waterbury, Norwalk, and Stamford. PILC is a legacy cable type approaching end of life in many locations. Rather than waiting for failures to occur which in underground systems can mean extended outages, manhole events, and serious worker safety risks, Eversource replaces PILC proactively based on age, condition assessment, and network criticality. Similarly, the replacement of substandard wood poles and the conversion of bare overhead wire to covered conductor are driven by the same data-based prioritization, which is known asset condition, tracked systematically and addressed before actual failure occurs.

This standards-and-data foundation also governs how Eversource sets its planning horizon. Capacity and reliability planning is conducted on a five-year forward-looking basis for distribution lines, far enough ahead to enable proactive investment, but close enough that load forecasts and interconnection assumptions carry high mathematical confidence. For the networks, capacity needs are evaluated using N-1 analyses, ensuring the network can sustain the loss of any single element without cascading failure under normal operating conditions.

5.2 Maintenance and Inspection Procedures to Prevent Failures

Substation Asset Condition

Eversource regularly evaluates the condition of its electrical facilities, with the overarching objectives of ensuring system reliability, minimizing risk to the electrical system, maximizing the useful life of assets, reducing lifecycle costs, maintaining a safe operating environment, ensuring good environmental stewardship, and conforming to all regulatory and industry standards. Allowing critical substation assets to deteriorate to the point of failure would create unacceptable safety and reliability consequences.

The existing substation assets vary significantly in characteristics such as age, voltage class, manufacturer, design, and expected service life expectancy. The environmental conditions also vary widely across the service territory, ranging from the coastal zones with

salt-air exposure to inland and mountainous regions with temperature extremes and wind loading. These factors influence the aging and degradation rates of equipment. As a result, while some facilities that are more than 40-50 years old show no significant asset condition concerns, others located in more challenging environments or containing specific asset types may require replacement in less than 20 years after installation.

Eversource has an ongoing obligation to monitor asset condition and proactively implement maintenance, repairs, component level or full asset replacements or upgrades as needed to maintain the reliability, safety, and integrity of the electric system. As assets age and their health degrade, they are more likely to fail and potentially cause prolonged customer interruptions. Eversource is responsible for implementing electric asset condition investments to replace degraded assets, to address performance issues, or to meet evolving standards and regulatory requirements. Through the implementation of targeted asset-condition investments, Eversource works to cost-effectively support the continued reliability the reliability of the Connecticut electric system.

Distribution Line Inspection and Maintenance

Annual Line Inspection

The distribution line system is patrolled on a 5-year cycle with 20 percent of the system completed each year. These patrols document conditions that may negatively affect system reliability. Completing the required repairs is necessary to maintain circuit health, support reliable service, and ensure the safe and reliable operation of the distribution system.

Infrared Inspection

Infrared inspections are performed on all distribution circuit backbones annually. These inspections identify 'hot spots' typically located at connectors, terminators, or splices that if not repaired may negatively affect system reliability. All 'hot 'spot' findings are prioritized and repaired within predefined timeframes to ensure a safe and reliable system.

Right-Of-Way (ROW) Inspection

All distribution ROWs are patrolled on an annual basis to identify distribution line damage that may negatively affect system reliability. ROWs are located off the public way where

any potential damage would not be identified by normal vehicular traffic. Findings are repaired through Maximo work orders to ensure the safe and reliable operation of the distribution system.

Pole Inspection

All distribution poles are inspected on a 10-year cycle. These poles are visually inspected for wildlife damage, insect infestation and tested for decay to ensure adequate pole strength remains. Poles with damage or that do not have adequate strength are considered reject poles and replaced under the pole integrity program to ensure the safe and reliable operation of the distribution system.

Manhole Inspection

The distribution line underground inspections are performed on below grade civil structures such as vaults, manholes, and service boxes on a 5-year cycle. These inspections identify structural civil and equipment issues (i.e. cable splices) that could pose a safety concern to either the public and/or employees. All findings are prioritized and repaired through the Underground Structural program to ensure the safe and reliable operation of the underground distribution system.

Direct Buried Inspection

Distribution line equipment located on concrete structures are inspected on a 10-year cycle. These inspections verify the equipment is safe to the public, operational and accessible. The equipment is also verified for potential environmental issues (i.e. oil leaks) to ensure the safe and reliable operation of the underground distribution system. Identified findings are repaired through Maximo work orders.

Vegetation Management

Eversource has submitted a comprehensive view of its Vegetation Management Plan under separate cover, as Exhibit CLP-VMP-1 and associated exhibits.

5.3 Technology Investments That Reduce Outages on Normal Days

Alongside data-driven planning and proactive asset management processes, Eversource has deployed automatic bus restoral schemes, reclosing devices and Distribution Automation that respond to faulted conditions automatically, faster than any field crew could, to minimize the impact of outages to customers, and have demonstrated measurable customer benefit.

Automatic Bus Restoral

For all standard substations, an Automatic Bus Restoral ("ABR") scheme, on the transformer secondary side, is designed/intended to restore supply to distribution buses after loss of supply due to loss of a transmission line of loss and/or a substation event that results in loss of the transformer that normally supplies that distribution bus. These schemes automatically isolate the secondary breaker of the primary transformer supply to the bus and then close a normally open tie breaker to another bus/transformer, restoring supply to the affected customers and avoiding what could otherwise be a prolonged customer interruption while the line or transformer are being replaced or repaired. As discussed earlier, the success of this scheme is predicated on having sufficient capacity and operational flexibility within a substation to pick up load during an (N-1) emergency event or planned outage event.

Reclosing Devices

Many faults on distribution lines are temporary in nature: a branch briefly contacts a wire; animal contact with energized equipment; conductors swing and momentarily touch; a lightning flash creates an arc between energized points. If the circuit is de-energized, these types of events could resolve themselves (the branch or the conductors would swing free, the arc will dissipate). As long as the circuit remains energized, these events would persist and cause a "permanent" outage requiring a crew response. Reclosers and trip savers attempt to clear temporary faults by automatically opening the circuit, waiting for a preset interval, then closing in an attempt to re-energize the circuit. If the fault has cleared, service is restored with no sustained interruption and no truck roll (instead, customers experience a momentary interruption). If the fault has not cleared, the reclosing device might repeat the attempt a few more times (depending on the setting) before it locks out and de-energizes the line.

Based on recloser PI data, approximately 1.1 million customers were spared from experiencing a sustained interruption in 2025 through this scheme. That figure covers only reclosers and breakers with reclosing relays. Trip savers, which also function like reclosers, provide equivalent protection but lack PI visibility, so the true total is higher. With full AMI deployment, Eversource would be able to quantify the complete benefit across both device types.

Reclosing Device Type	Count on System	2025 Estimate
Reclosers and Breakers	~5,800	~1.1M customers spared outage (PI data)
Trip Savers	~3,700	Not available (no PI visibility)
Total Reclosing Devices	9,500	~1.1M+ (reclosers only; total higher)

Important Limitation: Reclosing devices are highly effective during normal (blue sky) conditions, preventing ~40-50 percent of potential outages. During storms reclosers perform the same function and isolation as in blue sky day. The only difference is the extent of damage on a storm day. Without automation, the Company would have larger customer groups out of service and no remote capability to transfer load or close back in which would cause longer outage durations.

Distribution Automation

Distribution Automation ("DA") refers to network devices that can be controlled remotely or that automatically reroute power around a fault without requiring a field crew to physically operate switches. When a section of line fails, DA can switch customers to an alternate feed in seconds. Eversource's investment in DA has produced a very high benefit-to-cost ratio in the Eversource system, and the technology continues to be expanded across the network.

In 2025, if Eversource had no distribution automation, no automated reclosers or tie switching, the number of customers interrupted would have been substantially higher. Based on system data, that gap represents roughly ~2 additional interruption events per customer in 2025, an approximate 67 percent reduction in customer interruptions attributable to DA, at a time when the average Connecticut customer already experiences approximately one outage per year.

DA Component	Count on System	2025 Estimated Cust Avoided Interruption
Automated Reclosers (including ties)	~4,100	1.7M (blue sky) + 890K (storm)

Distribution Sensors

As technology continues to advance, the ability to leverage sensor data to provide edge device or refined data at closer points of the system and customer interconnections has proven to be critical in being able to not only provide real time operating conditions but to also leverage predictive analytics. Line sensors today can provide not only real-time voltage and current but power-quality measurements to determine the potential harm to customers' equipment, as well as the distribution system. One of the largest benefits of sensors today is the ability to detect downed conductors or wildfire ignition. These sensors can provide a level of information that can be brought back to a utility system operating center to make more timely decisions and organize responses to help minimize public or system safety risk. Eversource has deployed a number of new sensor technology such as Tripsavers, Vacufuses, line sensors, Line monitors (i.e Gridware), and controllers in its reclosers that provide telemetry to provide predictive analytics. In the capital investment plan, sensor technology continues to be an investment area that Eversource views as required to provide the level of safe and reliable operations given the demands on the distribution system today.

5.4 Operational Procedures to Quickly Restore Customer Service

Reliability performance is defined by how well we prevent failures from occurring and how quickly we recover from failures and limit customer impact. Over the course of time

Eversource has developed operational procedures to quickly respond to faults and restore customers in an efficient manner. The foundation of this response, whether during blue-sky days or active storm days is distribution crews that are dispatched to faulted locations to identify the causes of interruption, switch customers to other sources (if needed) safely repair the faulted system and restore normal service. The crews are dispatched from the twelve (12) Area Work Centers across the service territory which are strategically located to reduce the time required to respond to events on the system.

Working in concert with the field crews to ensure reliability, Operators in the control center provide the next level of operational control to improve reliability. These operators are able to identify fault locations, dispatch crews to faulted areas and remotely operate SCADA-enabled devices to isolate portions of the system and restore customers who are not in the faulted zone by switching them to other sources.

The highest level of operational control is provided by Distribution Automation devices, ABR and loop schemes, and reclosing devices (described earlier) which automatically isolate faulted areas, attempt to resolve temporary faults, and reconfigure the system to reduce customer interruptions.

5.5 The Limits of This Approach: Why Normal-Day Investments Are Not Enough

The tools and processes described above, planning and engineering standards, maintenance, inspection and operational procedures, data-driven investments, proactive replacement, reclosers, and DA, together represent a comprehensive strategy for managing system performance on normal operating days. However, many of these processes and technologies rely on a fundamental assumption that there are not multiple simultaneous failures and that the rest of the system outside the faulted zone remains intact. During major storms, that assumption breaks down entirely.

- Primary and backup feeds fail simultaneously, not sequentially.
- Circuit ties are between 13 and 45 percent unavailable on average during major storms. In the worst bare wire, high tree-conflict zones, ties can be up to 80 percent unavailable during catastrophic storms.
- Multiple faults occur simultaneously across dozens or hundreds of locations, overwhelming both automated systems and field crews.

- Customers who would normally be restored in minutes through automatic switching remain out for hours or days.
- Equipment is stressed beyond normal limits and might fail

This is not a design flaw. Rather, it reflects the limits of a system designed for an era of less frequent and less intense storms. The past 15 years have demonstrated that those design assumptions no longer hold. Addressing this structural gap requires a different category of investment entirely, which is referred to as "storm hardening."

6. Storm Resiliency: History, the Problem and the Plan

This section provides the full context for why a dedicated storm hardening program is necessary and cost justified to redress historical deficiencies in system design and provide the expected level of resiliency for customers in Connecticut.

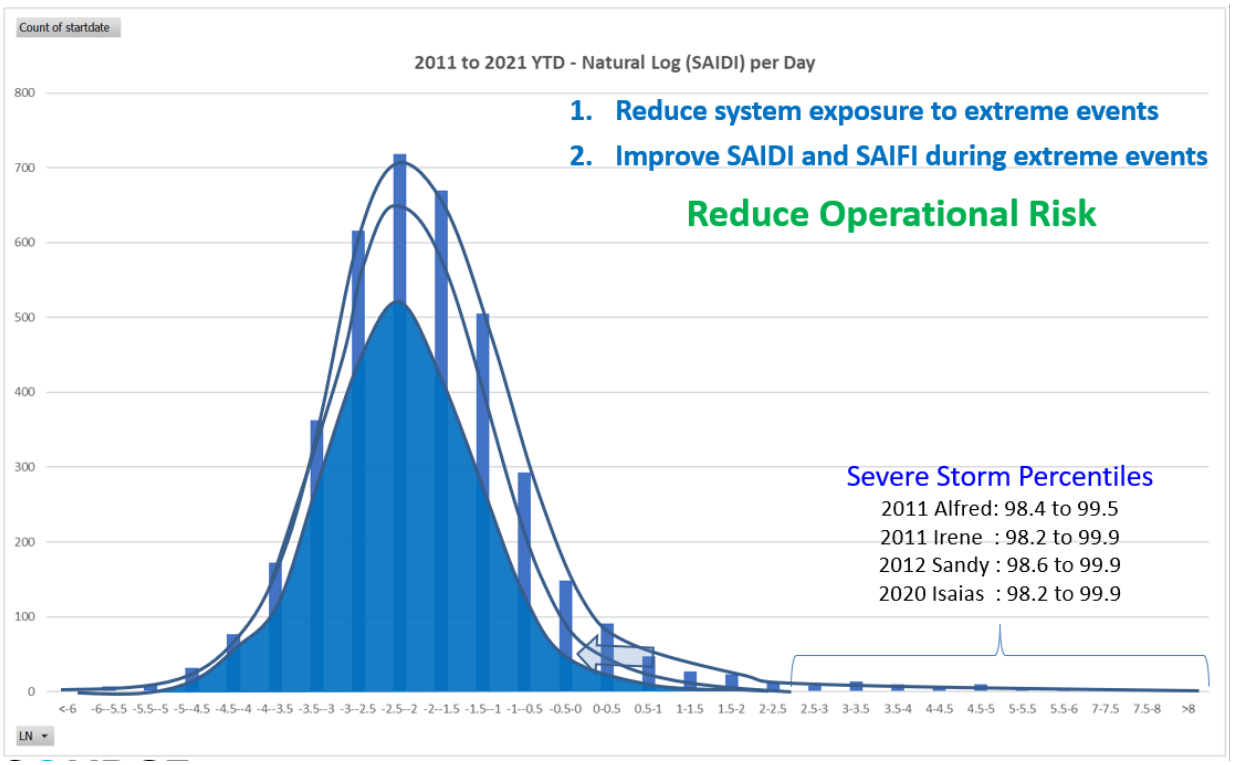
6.1 A Documented History of Catastrophic Storms

Connecticut has experienced four storms of once-in-a-generation severity in the past 15 years. This is not a projection — it is documented history:

Storm	Impact	Key Attributes
Tropical Storm Irene (Aug 2011)	650,000+ customers lost power	Saturated soils + high winds; widespread tree uprooting
Winter Storm Alfred (Oct 2011)	~880,000 customers (state record at time)	Early snowfall on leafed-out trees; up to 11 days without power; ~86 percent of CT without electricity at peak
Superstorm Sandy (Oct 2012)	Coastal devastation; $1B+ statewide damage	76 mph gusts in Bridgeport; ~10 ft storm surge on western CT shore

Storm	Impact	Key Attributes
Tropical Storm Isaias (Aug 2020)	750,000+ customers; $21M infrastructure damage	Statewide reach; nearly every community impacted; 7,054 outage events on Aug 4 alone (system record)

The statistical severity of these events underscores why standard reliability planning frameworks are insufficient for Connecticut's storm environment. An analysis of ten years of daily SAIDI performance from 2011 through 2021 shows that the distribution of storm-day severity is highly skewed, meaning that the vast majority of days cluster at or near zero system impact, while the four catastrophic storms identified above each registered at the 98th to 99.9th percentile of all days in the dataset – with Alfred ranging from the 98.4 to 99.5 percentile; Irene from 98.2 to 99.9; Sandy ranging from 98.6 to 99.9; and Isaias ranging from 98.2 to 99.9. These are not statistical outliers in the conventional sense. Instead, these storms were defining events that have determined the overwhelming share of lifetime customer-minutes of interruption. Investments and solutions that target only the normal distribution of daily events – the blue-sky and minor storm population – systematically under-invest in hardening against the events that matter most. The chart below illustrates this distribution, confirming that reducing system exposure to extreme events and improving SAIDI performance during those events are the central objectives of any meaningful resiliency plan.



The economic cost of this storm exposure is substantial and measurable. An independent review of Eversource's reliability and system resiliency programs conducted by Quanta Technology (now known as Danovo Energy Solutions) confirmed that resilience planning is fundamentally risk management, and that the avoided cost of power interruptions is a critical element in investment prioritization. Using the Interruption Cost Estimate (ICE) Calculator[1] methodology, the annual Value of Lost Load (VOLL) attributable to outage events affecting Connecticut customers encompassing both normal blue-sky operations and storm-related interruptions is estimated at $689 million annually. This figure captures the full economic harm experienced by residential and commercial customers through lost productivity, spoilage, and disruption.

In a catastrophic storm scenario equivalent to Isaias, the single-event VOLL impact rises to an estimated $10.6 billion, reflecting the scale of simultaneous, widespread, and extended customer interruptions that characterize the worst storms in Connecticut's

[1] https://icecalculator.com/

modern utility history. These figures establish that the cost of inaction, i.e., accepting the current level of system vulnerability, is not zero. It is measured in billions of dollars of economic harm absorbed by Connecticut customers and businesses with each recurrence of a major storm event.

6.2 The Economic Cost of Storm Vulnerability

Storm vulnerability has a measurable economic cost not just to Eversource, but to Connecticut customers and businesses. An independent review by Quanta Technology confirmed this using the industry-standard Interruption Cost Estimate (ICE) Calculator methodology:

Economic Impact Metric	Estimated Value
Annual Value of Lost Load (VOLL) – all outages	$689 million/year
Single-event VOLL – Isaias-equivalent catastrophic storm	$10.6 billion

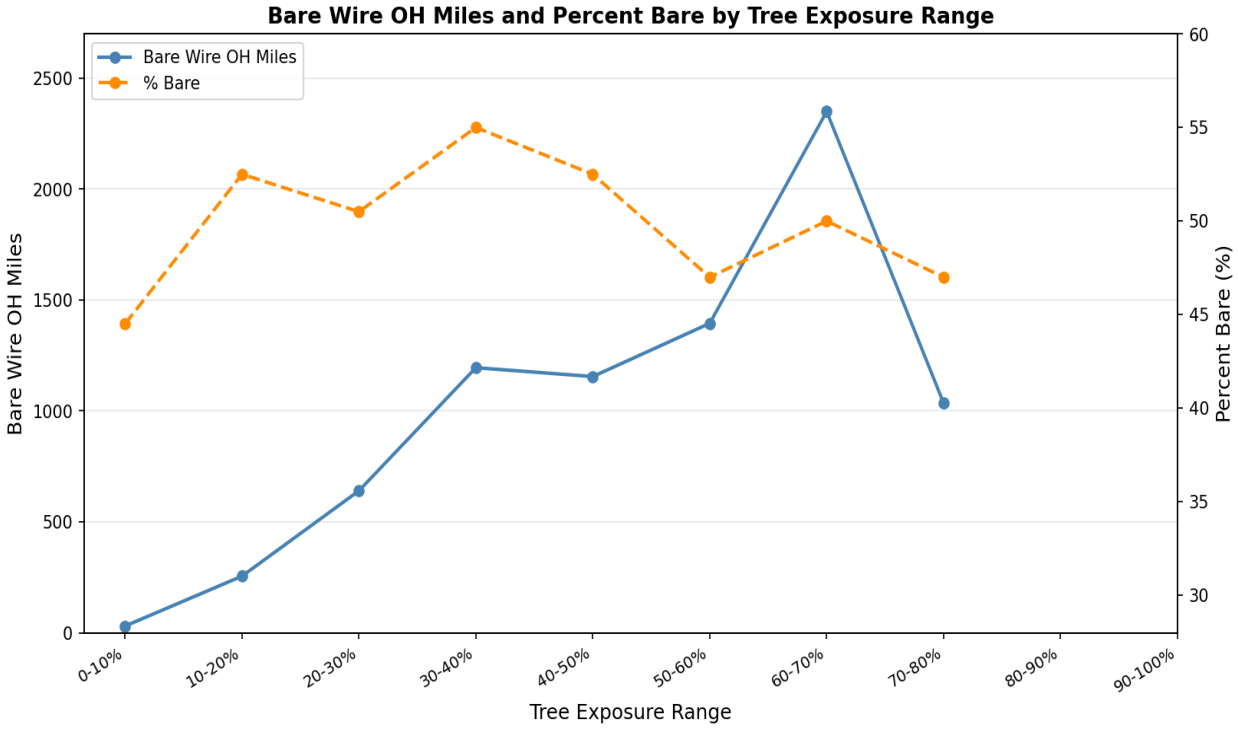
These figures establish that the cost of inaction is not zero. Every year that bare wire remains in high tree-conflict zones, every storm season that arrives with the same structural vulnerabilities in place, represents billions in economic harm absorbed by Eversource customers.

6.3 The Root Cause: Bare Wire in High Tree-Conflict Corridors

The analysis of storm outage data consistently identifies the same structural vulnerability: bare overhead conductor running through corridors with heavy tree exposure. This is not an equipment maintenance issue. Rather, this reflects a structural mismatch between infrastructure type and operating environment.

Bare wire has no inherent protection against tree contact and as shown in the chart below, a significant amount of O/H bare wire miles is areas with high tree exposure. Any wind-driven branch, limb, or fallen tree that contacts a bare conductor creates an immediate fault and a momentary or sustained outage. The heavier the vegetation in the corridor, the higher the fault rate. Zones with bare wire in the top 25 percent of vegetation risk classification account for a disproportionate share of total storm customer-minutes of

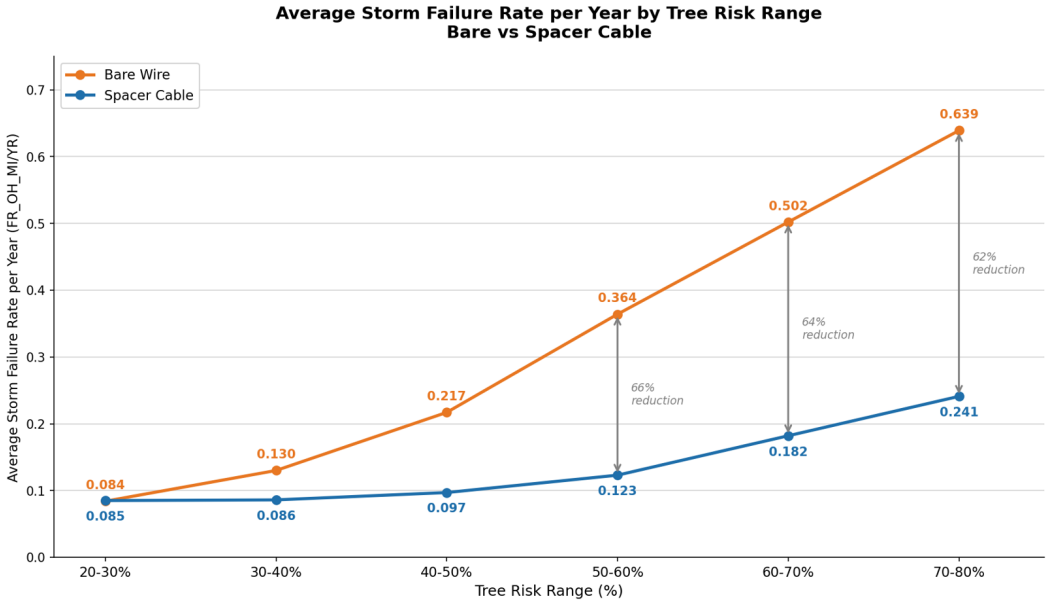
interruption and the same zones fail repeatedly, storm after storm, as confirmed by outage data.



6.4 The Solution: Spacer Cable Reconductoring

Within Eversource, three primary options exist for addressing bare wire in high tree-conflict zones:

- Vegetation Management: Trimming reduces contact exposure, but regrowth re-establishes encroachment conditions typically within 4 years. Trimming provides no durable structural improvement to protect against trees falling from outside the trim zone, that is only accomplished through tree removal. With the vast number of trees at risk for fall-in and the high number of hazard trees, the Company prioritizes removal for the optimal reliability impact.
- Underground Conversion: Eliminates overhead exposure entirely, but cost is several times that of alternatives. Less cost-effective in rural and suburban corridors where the cost and complexity of undergrounding is much higher.
- Spacer Cable Reconductoring: Replaces bare overhead wire with fully insulated bundled conductors held on a steel messenger wire by non-conductive spacers. Directly significantly mitigates the dominant storm failure mechanism at roughly one-third the cost of undergrounding in high tree-conflict zones, as shown below.



EVERSOURCE ENERGY

> Performance Evidence: Spacer cable is approximately 62 percent more effective than bare wire in preventing storm-related outages in high tree-conflict zones, capturing a significant portion of the storm performance benefit of undergrounding at roughly one-third the cost.

Spacer cable provides two distinct benefits:

- Electrical: Insulated conductors prevent tree contact from causing temporary or permanent faults.
- Mechanical: Steel messenger wire absorbs and distributes impact loads; bundled geometry reduces horizontal exposure to falling debris; spacers buffer impact energy between conductors.

6.5 The Storm Resiliency Plan: Proposed Investment

The proposed Storm Resiliency Plan represents a targeted, data-driven investment in the system's highest-risk bare wire corridors:

Storm Resiliency Plan Component	Value
Total investment proposed	$150 million
Miles of bare wire targeted for reconductoring	105 miles
High frequency zones identified	12 zones
Customers impacted	81,839 customers
Estimated annual CMI avoided (post-investment)	9.97 million customer-minutes/year
Selection method	All-In Predictive SAIDI model + CEMI storm event history

7. What the Company Cannot Control: External Factors and System Limits

7.1 Vegetation Growth Is Natural

Connecticut's forests continue to grow into, over, and around conductors every year. Eversource manages vegetation growth through a systematic trimming program, but:

- Regrowth re-establishes encroachment conditions within 4 years of trimming, with fast or young trees encroaching within 2 years.
- Approximately 55–60 percent of Connecticut's land area is forested, with 85 percent of trees over 61 years old.
- There is a very large population of trees outside the trim zone that are at risk of falling onto lines during storms.
- 90 percent of storm outages are tree-caused. Vegetation management manages risk but cannot eliminate this exposure.

7.2 Storm Frequency and Intensity Are Increasing

Connecticut's experience over the past 15 years reflects a documented pattern of more frequent and more intense storms. The climate and meteorological trends that drive this pattern, ocean surface temperatures, atmospheric moisture, storm track shifts, are outside the utility's control. Planning for the next generation of the Connecticut electric grid must account for this trend, not the storm climate of the 1970s or 1980s when much of the infrastructure was built.

This is evident in the IEEE Benchmarking study, which shows a downward trend of top-tier reliability performance across time (lower SAIDI = better performance), demonstrating that the goalpost for what constitutes "good" performance is continuously moving for all utilities. As Connecticut and Eversource's distribution system continues to experience frequent weather events, more commonly wind events, Eversource is upgrading the minimum standard pole sizes and conductor types.

7.3 Economic Cost of Inaction

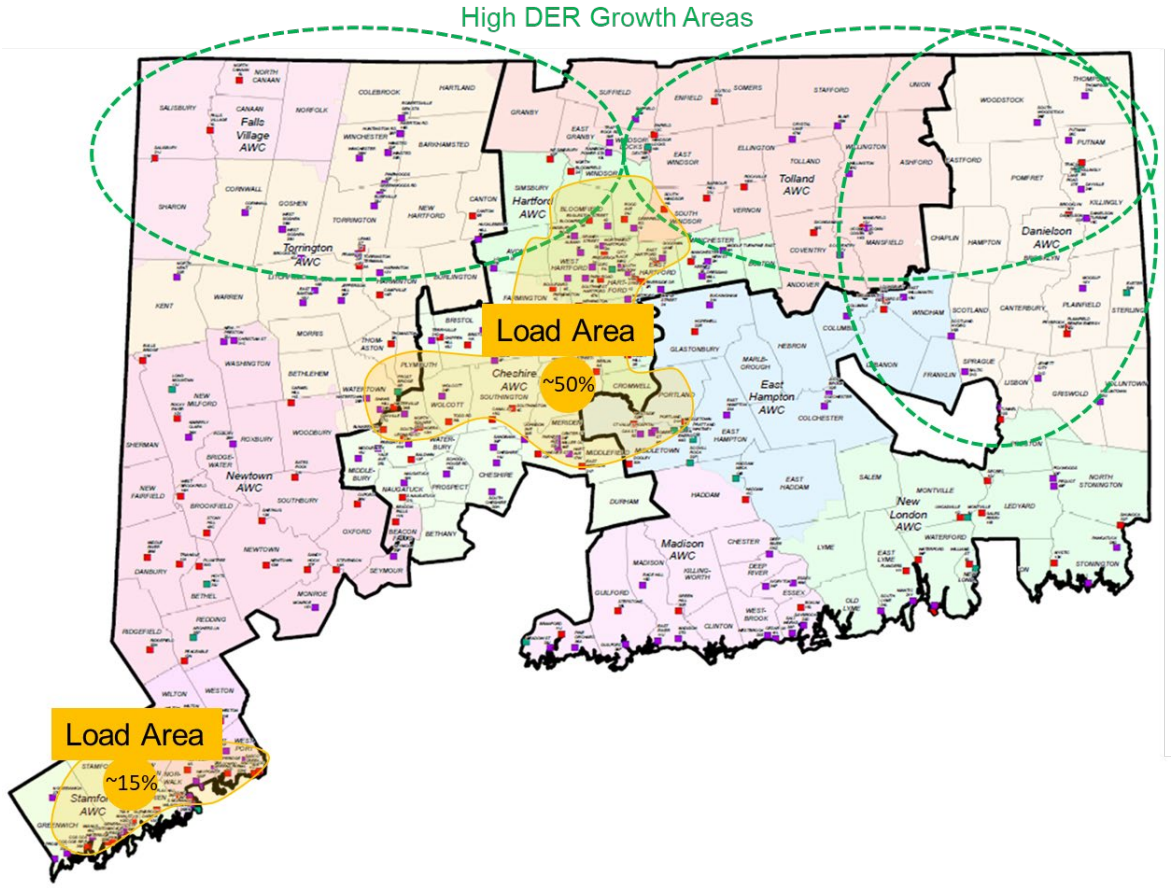
Standard reliability planning frameworks that optimize for average-day performance systematically under-invest in hardening against the extreme events that drive the overwhelming share of lifetime customer impact. A statistical analysis of ten years of daily SAIDI performance from 2011–2021 shows that the four catastrophic storms (Irene, Alfred, Sandy, Isaias) each registered at the 98th to 99.9th percentile of all days in the dataset. Planning that ignores this tail risk accepts billions of dollars of recurring economic harm.

8. Additional Considerations

8.1 Solar and other Distributed Energy Resources (DER) have grown exponentially in Connecticut, creating additional stress on the electric grid

In Connecticut, the Company currently has approximately 1,882 MW of DER installed and 950 MW in the interconnection queue. Most of the installed and in-queue DER, particularly large ground-mounted solar facilities are in rural areas of the state, such as Northwest and Eastern Connecticut, where there is not much native load and the electrical infrastructure has been historically designed with less capacity. Conversely, most of the load demand is concentrated in Central (~50 percent) and Southwest Connecticut (~15 percent) where there is less available land for ground-mounted solar development.

This misalignment of DER growth areas and load demand growth areas is driving the need for significant infrastructure build out to accommodate this increase in generation capacity. The following graphic highlights the major load growth areas the Company is observing, together with the regions covering the majority of solar development. Due to the land intensity of large-scale solar development, property prices are a key consideration in developer decision making processes, directing such developments to thinly settled regions.



Solar PV generation has changed the nature of power flow, from one-way transmission through substation to load, to bi-directional flow from the grid edge to loads, substations and even into the transmission system. Over the years, the aggregate amount of PV generation, especially in Eastern and Northwest Connecticut, has resulted in at least eight (8) substations that are saturated with DER, and experience reverse flow and transformer overload in the reverse direction during high DER generation, light load conditions.

Substation Name	Hosting Capacity (MW)	DER In-Queue (MW)	DER Online (MW)	Total DER (MW)
32P SHUNOCK	7	17	26	43
12S TUNNEL	0	21	80	101
12Y ROCKY RIVER	0	8	78	86
14R CAMPVILLE	0	9	40	49
13B FRYBROOK	0	60	10	70
14M TRACY	0	62	53	115
11F CARD ST	0	32	28	60
30K DOOLEY	9	30	15	45

At these eight substations, about 260 MW is unable to interconnect without major substation upgrades, leading to queue stagnation and project withdrawals. Across the state, over 550 MW of large solar projects are similarly stuck in interconnection queues across all Eversource substations.

To enable the ~260 MW of in-queue DER at these eight substations to safely and reliably interconnect, existing substation transformers would need to be upgraded, and, in some cases, additional transformers (substation expansion) would be needed. The cost of these upgrades is prohibitively expensive for any single project under the current cost causation principle. Innovative new methods would be required to unlock DER growth in Connecticut.

In Docket 22-06-29RE01, PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation – Non-Residential Interconnection Upgrades, Eversource presented a clear and convincing cost-allocation proposal and methodology (based on its experience with the Massachusetts Provisional

Planning Program for DER) that would enable over 460 MW of additional DER at the eight substations.[2]

Solar PV and other inverter-based resources (IBR) are challenging for equipment that was built for one-way power flow exclusively, particularly for protection schemes that are designed to prevent equipment damage and more significant outages when power flow is disrupted. This is an industry challenge, and Eversource engineers can design solutions to resolve these issues; but this often requires new equipment capable of detecting and accommodating the power to flow in either direction.

8.2 Communications Infrastructure Has Also Fallen Behind

As the complexity of grid operations increases with increasing prevalence of two-way power flow and increasingly unpredictable loads due to electrification and battery energy storage, the ability to have remote visibility and control of the distribution system becomes increasingly critical. The foundation of visibility and control capabilities is a robust and secure communications system that sends data and commands back and forth between field devices, such as reclosers and the 24/7 systems operations center (SOC).

In the 1990's, Eversource invested in a system called OpenSky, which is a 900 MHz licensed radio system used exclusively for transmitting mission-critical operational data between field devices and the SOC. The OpenSky communications network has reached its end-of-life and is no longer vendor supported. Failure of a single OpenSky tower antenna means that system operators cannot see or operate 50-100 reclosers remotely making that equipment essentially blind to power flow beyond the substation.

The need to replace the OpenSky system provides the opportunity to take advantage of advances in communications technology. Public carrier cellular is becoming increasingly viable for mission-critical operational data communications driven by expansions in coverage areas and the ability to roam from carrier to carrier, limiting the risk of failure due to third-party equipment issues. Public carrier

[2] NSTAR Electric Company, D.P.U. 22-47 (2022); NSTAR Electric Company, D.P.U. 22-52/22-53/22-54/22-55 (2024).

cellular also enables higher bandwidth data transmission that will be increasingly important for the modern grid, enabling remote firmware upgrades and adaptive protection.

The Company plans to upgrade the entire Connecticut system over the next seven years to bring a robust, resilient and reliable communication network to system operators regardless of weather conditions, bringing the system up to date and accommodating future needs.

8.3 In addition to automation, Eversource has deployed other types of software and technology solutions, although at a somewhat slower pace than other utilities given the operating environment.

As more data is collected from Eversource substations and overhead and underground equipment, the ability of SOC operators to process high volumes of data and quickly ensure safe and reliable operations is increasingly challenged. Historically, SOC operators relied on specific data points provided in the Company's supervisory control and data acquisition (SCADA) to manage power flows. The Company's SCADA system was upgraded in 2021, bringing that platform up to current standard. Real time grid operations, however, continue to increase in complexity and risk. The Company has improved its Control Room technology or "real time systems," however, important work remains to be completed, including:

- SCADA upgrade in 2021, as a platform for DMS/DERMS implementation.
- OMS upgrade in 2022, upgraded post Isaias to better support larger outages.
- No DMS
- No DERMS

Work and Asset Management system was deployed as a big step forward in the efficiency of designing and managing distribution equipment maintenance and capital.

- Integrates with mobile tools to dispatch work to crews in the field

- No graphic work design so project work is still designed essentially on paper and must be manually digitized

Data platforms required for advanced analytics (including AI/ML) require significant human intervention and slow the processing and benefits.

- GIS is the asset repository for distribution equipment but for assets deployed years ago, no written records were maintained and these data fields remain blank in the GIS system.
- Other data repositories also require significant human care and feeding to be used for data-driven analytics (e.g., Cascade, Powerbase).
- No comprehensive data platform is implemented, as yet.

9. Investment Plan Overview

9.1 Investment Plan Priorities

Eversource has developed a customer-focused plan that balances the following priorities:

- **Safety** – Eversource's #1 priority is to make sure any worker or member of the public does not get injured because of the Company's operations.
- **Reliability** – the bedrock of Eversource's mission is to provide customers with reliable power.
- **Affordability** – recognizing that electricity costs are an increasing burden, particularly for LMI customers drives the Company to focus on:
    - Data-driven cost effectiveness of investment decisions
    - Optimization of all our resources, processes, and technologies

9.2 Investment Plan Description

The investment plan is disaggregated into the following categories:

- **Emergent work on daily basis** – non-negotiable, critical activities that must be done to keep system running safely
- **Core Business** – to keep the system running and efficient
- **New Customer** – to connect new customer requests
- **Reliability** – to maintain and improve the system for reliable service to customers
- **Capacity** – to maintain system capacity to serve ever changing customer loads
- **Regulatory Commitments –** to meet commitments made to the regulatory authority
- **Telecom / Grid Modernization –** to replace aging communications infrastructure and invest in new technologies that modernize the operations of the system

The current level of investment is not sufficient to keep pace with current or future risks and will result in declining performance on all fronts, negatively affecting residential, commercial, and industrial customers as well as the overall economy of Connecticut.

Eversource is therefore highlighting three potential levels of investment, allowing flexibility to align with PURA's approved ratemaking approach.

- **Sustained Performance** – Minimum viable investment level to maintain reliability performance, meet regulatory obligations, maintain asset health and foundational system planning capacity for safety and reliable operations.
- **Targeted System Performance** – Baseline investment plus incremental investment for targeted reliability, advancing asset health and resiliency projects to improve performance on major event days while lowering emergent and storm costs.
- **Advancing the Grid** – Targeted System Plan plus investments that support state policy objectives such as DER integration and clean energy advancement, along with increased use of AI/ML innovations.

Performance Area	Sustained Performance	Targeted System Performance	Advancing the Grid
Primary Objective	Safe, maintain reliability, and meets Planning Criteria	System hardening and **reduced** storm cost	Modernize the grid to current industry standards
Operational View	**Stability-focused**	**Improved storm performance**	**Proactive and strategic**
Safety & Compliance	Supports evolving **regulatory requirements** (e.g., RE08)	Supports evolving **regulatory requirements** (e.g., RE08)	Exceeds minimum standards through risk-based investments
Reliability Performance	**Maintained** at current levels	**Improved** resiliency and system performance	Improved performance through **proactive** asset health
SAIDI / Customer Impact	Stabilized customer performance	Reduced outage duration and customer exposure	Reduced risk and improved system configuration
Emergent Failures	Minimal impact	Reduced through resiliency upgrades	Further reduced through proactive replacements
Asset Health	Targeted replacements to **prevent failures**	Improved right-of-way improvements	**Accelerated**, condition-based asset renewals
System Capacity	Meets planning criteria, focused on 10-year violations	Meets planning criteria, focused on 10-year violations	Meets planning criteria, focused on 10-year violations
Automation	Maintains system automation (DMS, DERMS)	Increased system automation	**Expanded** automation to improve restoration and efficiency
Resiliency (Storm Cost)	**No dedicated** resiliency investment	**Proactive, system-level resiliency investment, storm cost reduction**	Further improved through proactive asset replacement
Cost Trajectory	Lower near-term spend; higher Emergent and capital risk	Increased system investment to reduce storm operating cost	Higher upfront investment; lower long-term operating cost
Alignment with Regulatory Policy	Set foundation for PBR, reduced regulatory risk (RE08)	Regulatory aligned	Aligned with lower regulatory risk in outer years

10. Conclusion: A System in Transition

The Eversource electric distribution system in Connecticut is a large, complex and aging infrastructure network operating in one of the most challenging environments for overhead electric delivery in the United States. The system serves approximately 1.3 million customers across a state that is simultaneously one of the most densely populated and most heavily forested in the nation.

The system's current challenges are a product of historical design choices made under different conditions, absent the demands of advancing electrification, a maturing and expanding forest canopy and an intensifying storm climate. These are not problems that Eversource created, but are problems that Eversource must solve systematically, cost-effectively, and with full transparency to the regulators and customers who depend on this infrastructure.

The investments described in this filing storm hardening, automation, data-driven targeting of the highest-risk infrastructure, underground cable renewal, and pole replacement represent a coherent, evidence-based strategy for improving system

performance over time. No single investment eliminates the risk. But each targeted investment measurably reduces operating risk for the benefit of customers in the zones that need it most.