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EVERSOURCE
ENERGY

Distribution System Planning Guide

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1. Overview

This Distribution Planning Guide has been developed to provide Eversource Energy (“the Company”) with a consistent uniform approach to designing an efficient and reliable electric distribution system to provide the quality of service expected by our customers. The Planning Guide is aligned with applicable safety codes, regulatory requirements, and industry standards (referenced in Section 5) and provides uniform criteria and design standards across the Eversource Service Territory for all aspects of the System Planning Process.

The electric power industry is undergoing significant change with: increasing customer expectations for reliability and resiliency; widespread adoption of new, often disruptive, technologies including Distributed Energy Resources (DER), electric vehicles (EV), and smart homes; utility grid modernization initiatives; and a rapidly evolving regulatory landscape. These changes and other advancements have not altered the basic mission of the distribution system, but have impacted the way we way approach planning, the data sources and methods, scenarios and simulation cases, and the range of possible solutions considered for mitigation.

The Company’s unique electric system, supplying both high density urban areas and rural areas across three states, affords planners a great degree of flexibility in adapting the system to meet customer needs in a cost-effective manner. However, due to the legacy standards and practices in different operating areas, there is pressing need to harmonize standards and practices across the Company and provide clear, uniform consistent guidelines for how and when to expand the system to meet load and DER growth. The application of these panning standards will provide long term improvements in system performance in response to recent challenges facing the electric utility industry.

1.1. General

The basic goal of distribution planning is to provide orderly, economic expansion of equipment and facilities to meet future system demand with acceptable system performance. The key planning objectives include:

- Build sufficient capacity to meet instantaneous demand
- Satisfy power quality/voltage requirements within applicable standards
- Provide adequate availability to meet customer requirements
- Deliver power with required frequency
- Reach all customers wherever they exist

Since the electric utility is often the provider of last resort, planning the system is delicate balance between performance and cost. Planning engineers must identify the goals for system performance, understand how differences in system design and equipment will affect achievement of the goals, and find the most suitable design solution to meet performance goals.

Balancing cost and performance to find the most suitable design solution is made more challenging by a number of factors, including performance pressures, cost escalation, aging infrastructure, DER/EV penetration, and state/regulatory mandates.

This Distribution Guide outlines the planning criteria, design and analysis methods and engineering rationale for effectively expanding the distribution system to meet demand. The planning criteria builds upon existing company standards, mainly the Distribution System Engineering Manual (DSEM) and the SYSPLAN standards, as well other legacy standards such as NH - ED3002.

1.2. Scope

The scope of the Distribution Planning Guide is comprehensive, including traditional planning considerations for expanding the system to avoid capacity, voltage and reliability violations as well as advanced planning concepts related to Non-Wires Solutions (NWS), Battery Energy Storage System (BESS) and other DER application, and integrated load/DER forecasting with EV adoption.

The foundation of the planning methodology is an advanced distribution analysis platform to enable key planning activities. The application can import system models from GIS, integrate demand and DER data from linked sources, and incorporate forecast and adoption models to build daily (24-hour) and yearly (8760-hour) planning scenarios.

2. Planning Criteria

2.1. Introduction

This guide defines the criteria Eversource uses to determine how to plan and design the system to avoid loading, voltage, and reliability violations during normal and emergency system operation, as defined is Reference Section 5.

2.2. Thermal Loading Criteria

The topics below define the application of thermal loading criteria for substation transformers and conductors used in the distribution system.

The methods for determining the normal and emergency rating of bulk distribution transformers is covered in Section 3 of this document. Eversource Distribution System Engineering Manuals (refer to Section 5 references) provide the methods for determining the normal and emergency rating for distribution lines and equipment. The criteria below define the safe and reliable utilization of rating limits, specified by Eversource Standards, under both normal and emergency conditions. They address the existing system design as well as future design changes planned for the distribution system.

When analyzing system load versus Normal, Emergency, LTE, and STE ratings, it is done with respect to the applicable seasonal ratings (e.g. winter and summer).

2.3. Substation Transformer

The design criteria noted below may be more restrictive than a transformer's Normal rating. This does not necessarily limit the actual operation of the transformer equipment, which may be utilized to the full extent of its normal rating, but it provides for pre-load conditions that will maintain the equipment below acceptable LTE and STE rating following emergency conditions.

Bulk Distribution Transformer loading is evaluated on a winding basis, that is the load carried by each individual winding is evaluated against that winding's rating(s). Bulk Distribution Transformer windings shall have ratings determined per the requirements of Eversource Procedure SYSPLAN 008, refer to Section 3.3, and shall be applied in the following manner.

Bulk Transformers, Normal Operation – CT/MA

Loading Up To 75% of The Normal Rating:
Bulk transformer winding loads (expressed in Amperes or MVA), should not exceed 75% of the normal rating, under normal (scheduled) operating conditions/configurations.

Notes:

- When determining LTE and STE ratings of a transformer winding, a 75% pre-load condition is assumed. Therefore, to protect the integrity of the emergency ratings, normal loads should be limited to 75% of the normal rating[1].
- Loading up to 100% of normal ratings can be used for single transformer substations, when that transformer is not relied upon to provide secondary supply to another bulk distribution supply bus.

Loading Between 75% of The Normal Rating and the Long-Term Emergency (LTE) Rating:
Bulk transformer winding loads above the normal rating, but below the LTE rating are allowed for one Event (24-hour load cycle). Transformer winding loads within this range result from contingency events in the distribution

[1] Applies to transformers that provide contingency (N-1) supply to load normally served by other transformers. Utilization at this level balances the maximization of the contingency STE rating with that of base capacity, ensuring that a substation has sufficient capacity to maintain continuity of service for customers in the event of loss of a transformer.

system or within substations (loads in this range may result from ABR operations).

Note:
Load transfers (within the distribution system) or installation of a mobile transformer should be available to lower winding loads to the normal rating (or below) for subsequent load cycles following the contingency, or until the system can be returned to normal conditions.

Loading Between the Long-Term Emergency (LTE) Rating and the Short- Term Emergency (STE)/ Drastic Action Limit (DAL) Rating:
Bulk transformer winding loads above the LTE rating, but below STE/DAL rating must be lowered to below the LTE rating within 30 minutes.

Loading Above the Short-Term Emergency (STE)/Drastic Action Limit (DAL) Rating:
Loading transformer windings above the STE/DAL rating is not acceptable under planning criteria for any duration. This is intended as an emergency operational practice only. Automatic protection schemes shall be applied when needed to prevent loading bulk substation transformer above the STE rating.

Note:
Operating a transformer, for any duration, at loading levels above the STE rating can result in loss of life or in extreme cases, increased risk of catastrophic internal failure of the transformer.

Bulk Transformers, Normal Operation – NH

For all transformers in New Hampshire, loading shall not exceed 95% of the Normal rating. Maintaining transformer loading at a higher threshold under normal (N-0) system conditions increases the risk of equipment failures and exposure to customer reliability interruptions under N-1 contingency conditions. This variation in design criteria, from the standard 75%, is to allow maximum utilization of the existing population of 34.5kV transformer that do not exhibit a significant reduction on STE rating when applying a 95% preload. For those transformers where STE performance impacts the ability to restore customers automatically (as per Section 2.8) the standard 75% preload should be maintained.

Non-Bulk, Normal Operation (N-0)

For all non-bulk transformers on the Eversource system, planned loading shall not exceed 100% of the Normal rating.

Non-Bulk, Contingency Operation (N-1)

With available load transfers, the loading on a transformer shall be reduced to below the LTE rating. Load levels can only be sustained above the Normal rating for one load cycle.

2.3.1. Loading Limits for Conductors used in the Distribution System:

The topics below define the application of thermal loading criteria for conductors used in the distribution system, calculated values for cable and wires thermal loading limits in Amps is provided in the DSEM Section 08.00 by conductor type.

Cables and Wires supplying underground and Overhead Areas:

Normal Operation (N-0)
During normal system conditions, load levels shall not exceed the Normal rating. The normal rating is the maximum loading without incurring loss of life above the design-loading limit.

Contingent Operation (N-1)

Cables
During contingent system conditions of the electric system, load levels may not exceed Normal Ratings for Cables[2]. System changes shall be developed when cable limits are expected to exceed 100% of Normal rating during contingency operations. Operating above the Normal rating may involve loss of life or loss of tensile strength for conductors, loading must be reduced after one load cycle (24-hour period)

Wires
During contingency system conditions of the electric system, load levels may not exceed the following criteria:

- NH – Wires shall not exceed emergency rating, as per Distribution System Planning and Design Criteria Guidelines (ED-3002)
- CT/MA – Wires shall not exceed normal rating[3]

2.3.2. Load Balance

Distribution feeders shall be arranged in order to give the best possible load balance on the system. In Distribution feeders where load imbalance exceeds 50 amps between phases, necessary improvements should be considered to reduce imbalance to less than 50 amps.

2.3.3. Feeders Supplying Underground Network System:

All network feeders are designed to operate within their normal rating at all times of the year. In addition, the feeders are designed to operate within their normal ratings in the event of the loss of any one (N-1) feeder in the grid. This is done in order to provide some level of protection against a double contingency. The feeders should also be designed to operate within their LTE rating in the event of a double (N-2) contingency.

2.3.4. Distribution Supply System (DSS) Lines

Under normal configuration the loads of all lines (in service) in the line group will be below the normal ratings at all times.

During a single contingency (N-1) condition, where one of the lines is out of service, the load on any one of the remaining lines should not exceed its long-term emergency (LTE) rating.

2.4. Voltage

Operating voltage limits allowed on Eversource Energy Distribution circuits, principally for residential or commercial services, are covered in the DSEM (refer to Sections 5 and 7). These voltage limits are also used as a reference when analyzing customer voltage problems and designing distribution circuits.

Upper and Lower Voltage Limits

State	Voltage Limits
CT	Connecticut upper and lower voltage limits are those prescribed in Section 16−11−115, Voltage Variations, of the Regulations of Connecticut State Agencies. Voltage excursions above the upper limit shall not exceed one minute. American National Standards Institute (ANSI) C84.1−2016 shall be used to determine the lowest temporary voltage excursions permissible.
MA	Massachusetts limits are based on voltage guidelines in ANSI C84.1−2016.

[2] In compliance with the Department's guidance in Docket Number 17-12-03, PURA Investigation into Distribution System Planning of the Electrical Distribution Company
[3] In compliance with the Department's guidance in Docket Number 17-12-03, PURA Investigation into Distribution System Planning of the Electrical Distribution Company

State	Voltage Limits
NH	New Hampshire limits are based on New Hampshire Code of Administrative Rules, Rule 304, Quality of Electric Service. These limits are based on voltage guidelines in ANSI C84.1.

Table 1- Upper and Lower Voltage Limits

Contingency Voltage Limits

CT, MA, and NH state regulations allow for temporary voltage excursions outside the normal range at the customer service entrance during contingency operating conditions. Some examples of temporary contingency conditions are listed below. For CT, temporary voltage below the lower limit should not exceed 24 hours where practical. Voltage excursions above the upper limit are not identified by magnitude but shall not exceed one minute. For WMA and NH, voltages above and below normal limits are based on ANSI C84.1 guideline and shall be limited in extent, frequency, and duration. When they occur, corrective measures shall be undertaken within a reasonable time to improve voltages to meet normal voltage range requirements.

Contingency operating conditions, when temporary voltage excursions are allowable, include (but are not limited to) the following:

- Autoloops when a circuit, or part of a circuit, is being supplied through a tie recloser
- Automatic transfer schemes when fed by the backup feeder
- Contingent, manually switched supply to load in response to an interruption of normal supply routes or as needed for line construction, not exceeding 24 hours in expected duration
- Secondary networks with one or more supply feeders out of service
- Secondary networks with one or more network transformers out of service
- Forced outages of bulk power transformers
- Forced outages of transmission lines

Additional information on voltage variation among phases and calculation of voltage unbalance is included in the Distribution System Engineering Manual Section 05.131 to 05.135 (refer to Section 7),

High and Low Normal and Contingency Limits Summary

The Tables below list the high and low normal and contingency service voltage limits for all three states in the Eversource system:

Nominal Voltage	Normal High Limit	Normal Low Limit	Contingency Low Limit
120	123.6	114.0	110.0
208	214.2	197.6	190.7
240	247.2	228.0	220.0
277	285.3	263.2	253.9
480	494.4	456.0	440.0
600	618.0	570.0	550.0

Table 2- Connecticut Service Voltage Limits (Volts)

Nominal Voltage	Normal High Limit	Contingency High Limit	Normal Low Limit	Contingency Low Limit
120	126	127	114	110
208	218	220	197	191
240	252	254	228	220
277	291	293	263	254
480	504	508	456	440

Nominal Voltage	Normal High Limit	Contingency High Limit	Normal Low Limit	Contingency Low Limit
600	630	635	570	550

Table 3- Massachusetts & New Hampshire Service Voltage Limits (Volts)

2.5. Power Quality

System Planning follows the latest approved version of the "Eversource DER Information and Technical Requirements for the Interconnection of the Distributed Energy Resources (DER)" to complete analysis of:

- Steady-state Thermal and Voltage Criteria
- DER Impact on Voltage Regulating Equipment
- Transformer Reverse Power Capability
- Rapid Voltage Change and Voltage Flicker
- 3V0 Assessment[4]

System Planning also follows the transient overvoltage curve in IEEE Std. 1547─2018, clause 7.4.2. limiting the transient overvoltage to less than 1.2pu. This is a critical section due to potential load rejection overvoltage (LROV) by the inverters, which can potentially cause damage to utility equipment, and/or nearby customer equipment.

2.6. Load Density

One important metric utilized by Planning Organizations, to determine the substation design and reliability criteria required to supply specific geographic areas is load density. This is defined by Distribution System Planning as MWh Energy Demand for a whole year over the Supply Area in square miles:

- High Load Density areas are those greater than 750MWh/square miles or comparable to Downton Boston, MA.
- Medium Load Density areas are those between 250MWh/sq-mi and 750MWh/sq-mi or comparable to Stamford, CT and Somerville Area, MA.
- Low Load Density areas are those less than 250MWh/sq-mi or comparable to Plymouth, SEMA.

MWh Energy Demand is calculated by using a sampling rate of 1 hour and actual MWh readings for an entire year (8760 hours) from all the distribution stations supplying the targeted geographic area. The Supply Area (square miles) is the geographic boundary of all the distribution circuits that normally supply load via the targeted stations. The distribution circuit boundary extends up to the last distribution or non-bulk transformer supplied by the targeted Substation and does not cover the length of additional tie lines to other stations. The geographic boundary includes all habitable land, including small parks and recreational areas, but not the areas covered by large green areas or water bodies (state forest, large parks, ocean, lake, ponds, and/or wetlands).

Based on the above definition:

- Area Work Centers (AWC) in the CT and NH service territory currently fall within the Low to Medium Load Density Criteria
- Somerville and Mass Ave AWC fall within Medium to High Load Density Criteria
- Metro Boston Network area falls within the High Load Density Criteria
- Other MA service territory (except for Somerville, Mass Ave and Metro Boston) currently fall within the Low to Medium Load Density Criteria.

2.7. Reliability

2.7.1. Bulk Distribution Substations:

[4] Eversource requires ground fault (zero sequence) overvoltage ("3V0") protective relaying package to be installed on the transformer high-voltage side to detect the ground fault overvoltage when the upstream transformer connection is delta and the DER is about 50% of minimum load.

Within its service territory, Eversource supplies a range rural and urban areas which often differ in electric supply characteristics and requirements. Electric distribution substations are scaled in size and redundancy as a proportion of the mix between rural and urban areas. To maintain adequate levels of reserve capacity, power quality, and reliability, that meet or exceed our Customer's increased expectations, Bulk Distribution Substations shall be designed to sustain any Single Contingency (N-1) with no Load Loss.

Transmission System Considerations:
Upholding the Bulk Distribution Substation N-1criteria starts at the transmission level, by observing the following:

- The transmission system supplying distribution bulk substations shall be designed so that the outcome of any single contingency event at the transmission side does not result in a condition greater than a Single Contingency (N-1) at the distribution bulk substation.

Distribution System Considerations:
Upholding the N-1 design standard also applies to the distribution system by observing the following:

- The distribution system shall be designed so that any feeder outage does not result in thermal or voltage violation above design criteria, as defined Sections 2.2 and 2.4.

2.7.2. Distribution System Reliability

Distribution Feeder design is intended to provide safe, reliable service within allowed voltage limits at a reasonable cost. Reliability generally addresses interruptions of service exceeding the targets specified by state regulators. Eversource uses three reliability measures adopted by the utility industry: SAIDI, SAFI and CAIDI, refer to DSEM 02.11. There are limits as to what degree of reliability is practical or achievable, depending on the investment cost and rates permitted by regulatory authorities. To evaluate the effectiveness of reliability projects and determine the most cost-effective solution Eversource follows DSEM 03.30.

To maintain approved regulatory reliability indices, the following solutions can be implemented in areas of the distribution system that required reliability improvement:

- Add automatic sectionalizing devices to limit exposure to 500 customers or less per switchable zone. Refer to DSEM 02.30, DSEM 06.51, and DSEM 10.42.
- Eliminate or reconfigure triple circuit pole lines to minimize customer exposure for single emergency events that result in more than 1000 customers out of service
- Reconfigure double circuit pole lines where both the normal and alternate source supply the same group of customers resulting in more than 1000 customers out of service.

2.8. Standard Substation Design

While it may not be possible to design, build, and operate substation facilities that are completely resilient to any event which could result in customer outages, there are economic designs and technologies that minimize the occurrence and/or impact of substation-based events to improve reliability. At the distribution level, it is Eversource's goal to have customer's electric service automatically restored upon loss of supply to Bulk Distribution Supply Buses.

In areas of High Load Density, a higher degree of reliability is required by maintaining supply, without the loss of power, to Bulk Distribution Buses following an N-1 Contingency Condition.

To accomplish this, certain technologies/designs are considered:

- Each distribution bus providing service to high load density areas shall have at least two means of supply connected in a parallel. In this context, the preferred primary supply is provided by connection to the secondary winding of a Bulk Distribution Transformer, and secondary supply is provided by connecting to a normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different Bulk Distribution Transformer.
- Each distribution bus providing service in low to medium load density areas, shall have at least two means of supply (primary and secondary). In this context, the preferred primary supply is provided by connection to the secondary winding of a Bulk Distribution Transformer.
    - Secondary supply for distribution buses is provided by a connection to bus tie breakers (either

normally open or normally closed) that connects to another bus that is supplied by the secondary winding of a different Bulk Distribution Transformer within the same substation.

For all Standard Substations, Automatic bus restoral schemes (ABR), on the transformer secondary side, are designed/intended to restore supply to distribution buses after loss of supply due to transmission and/or substation events 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.

Secondary bus arrangement for Standard Bulk Substations shall consist of two or more standard size transformers connected at the secondary side via a Ring Bus or Double Bus Switchgear configuration, refer to Figure below:

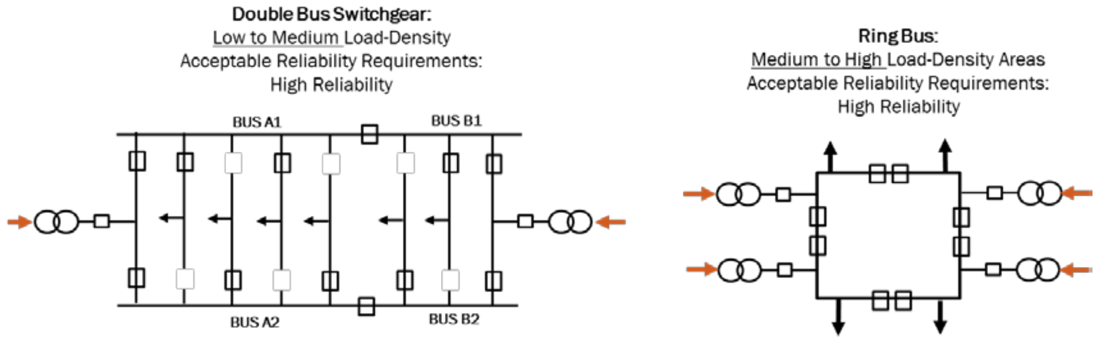


Figure 1 - Standard Substation Design

The preferred secondary bus arrangement design for new substations or substation upgrades shall be driven by the expected load density, based on long-term forecast of the area to be supplied. Low to Medium Load-Density areas shall be planned as Double Bus Switchgear configuration, and for areas with Medium to High Load-Density future substations shall be planned as a Ring Bus Configuration. In both substations arrangements, the system shall be design so that a bus fault does not result in loss load. In the Double Bus Switchgear this is accomplished by transferring the load to the non-faulted bus, in a Ring Bus Configuration the distribution system is designed to account for a bus fault.

Standard Bulk Distribution Substation shall be designed to meet the following criteria:

- Available short circuit currents shall not exceed the protection equipment's interrupting capabilities, both inside the substation and the distribution system:
- Short circuit currents that exceed protection equipment interrupting capability can result in equipment damage, widespread outage events, and concerns in maintaining personnel and/or public safety near such equipment. To minimize the risk, impact, and possibility of such events, simulations shall be conducted to evaluate the maximum short circuit current in a substation against the protection equipment's capability of interrupting it.
- The System Protection and Control department is responsible for this determination.
- Bulk Distribution Substations shall be designed such that the limiting element is the Substation Transformer(s).
- Capability to ensure Bulk Distribution Transformer winding loads can be maintained within the applicable rating during both normal and post-contingency conditions as per Section 2.2.
- Sufficient VAR support to maintain scheduled bus voltage values during normal and post-contingency (N-1) conditions.
- Capability and proper load balance between secondary buses to ensure:
    - Secondary bus loading is not exceeded during normal and post-contingency (N-1) emergency conditions.
    - Substation equipment and getaway cable loading is not exceeded during normal and post-contingency (N-1) emergency conditions.

2.9. Substation Upgrade Criteria

Bulk Distribution Substation designs should be in accordance with the design criteria specified in the Section 2.8 When existing substation designs do not conform to these criteria or future potential non-conformances are identified, as part of the Solution Development Process in Section 4.8, plans shall be developed to address identified violations. This section outlines the process for prioritizing needed upgrades required to mitigate capacity, power quality, and reliability violations.

To maximize the benefit of available funds and resources, the Eversource distribution bulk substations system improvement objective is to prioritize upgrades addressing violations based on the following priorities, in order:

1 - Highest to lowest overloads under normal and contingency (N-1) conditions
2 - Load loss under first contingency (N-1) conditions
3 - Highest to lowest number of customers impacted during contingency conditions
4 - Associated risk evaluation of substation based on individual components (Asset Condition).
    a - This Asset Condition criteria does not include equipment with asset conditions deemed a safety hazard, those should be prioritized and resolved under emergency conditions.

This objective ensures that violations addressing distribution substation overloads, both bulk and non-bulk, are prioritized due to the risk that equipment failure can pose to the public and employee safety. Moreover, violations that impact the reliability of the electric service we provide to our customers is also prioritized by addressing violations that result in a Single Contingency Load Loss. A reliable electric grid brings a host of benefits beyond reduced outage time to those affected by power outages (e.g., by providing greater assurance to businesses and emergency personnel that their activities will not be inconvenienced by electric outages). Lastly, by prioritizing reliability driven replacement of substation transformer and/or equipment as a factor of the load density, the number of customers affected by equipment failure is reduced (e.g., replacement of transformers that are over their useful life and are supplying high load density areas shall be prioritized when compared to similar transformers supplying low load density areas).

After the yearly distribution substation assessment process, Distribution System Planning shall identify all violations per individual substations and rank them by state based on the priority given in Table below.

Priority Number	Violation Type	Description
1.	Capacity	Bulk Distribution Substation Overloads
2.	Capacity	Non-Bulk Distribution Substation Overload
3.	Reliability	Single Contingency (N-1) load loss
4.	Reliability Power Quality	Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying High Load Density Areas
5.	Reliability Power Quality	Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying Low Load Density Areas
6.	Power Quality	Power quality Violations such as Harmonics, TOV, ROI
7.	Reliability	Non-Standard Substation Design

Table 4 - System Violation Ranking

Single Contingency Load Loss (SCLL)

SCLL is identified as complete or partial interruption of load served by a Substation for a sustained period due to the absence of automatic throw-over schemes on the transmission end or load swap schemes on the distribution end, (e.g. load supplied from radially fed circuits with no ties.)

Eversource System Operating Procedure (ESOP-28) - Single Contingency Load Loss for the respective state. supports the identification of events which result in customers being fed by a single transmission path, a loss of which would lead to complete or partial interruption of load served by a Substation for greater than 90 minutes due to the absence of automatic throw-over schemes on the transmission end or load swap schemes on the distribution end. Eversource has an established process to identify, review, and notify stakeholders of these SCLL situation to manage the risk of having these types of event occur. This process is specified in the ESOP-28 and applies to Eversource CT, MA, and NH electric transmission and distribution organizations. The process ensures involvement of stakeholders and management in reviewing, preparing for, and issuing any needed notification for outage work that creates a SCLL condition. Completion of the SCLL process in advance of the scheduled outage ensures that plans are in place to minimize risk exposure and mitigate customer load interruption.

Distribution System Planning should identify SCLL conditions due to substation transformer or switchgear outages that result in exposures exceeding the conditions cited in ESOP-28. When developing preferred and alternate solutions that will be implemented in the 5-year capital plan, as part of the solution development process in Section 4.8, Distribution System Planning will assess the severity of potential SCLL conditions and document these findings as part of the Solution Selection Form (SSF). Where SCLL risks are deemed to be severe, such risks would be considered in the design of the applicable solution.

For events that could potentially exceed the ESOP-28 criteria, the following information should be documented as part of the preferred solution:

- The next event (transformer or switchgear outage) that will result in the greater number of customers out of service.
- Identify transformer or switchgear equipment age and/or known asset conditions.

2.10. Feeder Upgrade

Feeder upgrades are required when one or more of the following design criteria is violated to ensure that any feeder cable/wire will not exceed Normal or Emergency Ratings, as per Section 3.1.

Cables and Wires Supplying Underground and Overhead Areas:
System modifications shall be developed and proposed when conductor limits are expected to exceed the following:

- 80% of normal feeder rating for cables
- 90% of normal feeder rating or emergency for wires

Feeder Supplying Underground Network Systems
System modifications shall be developed and proposed when conductor limits are expected to exceed the following:

- 80% of normal feeder rating

Distribution Supply System (DSS) Lines
System modifications shall be developed and proposed when DSS Lines are expected to exceed the following:

- 80% of normal or emergency rating for cables
- 90% of normal or emergency rating for wires

2.11. Battery Energy Storage System Design Criteria

Eversource defines the deployment of energy storage as a distribution grid solution, and the process for identifying scenarios where battery energy storage solutions would be most beneficial. Energy storage can be classified as a Non-Wires Solution (NWS) option or as a standalone technology that can be deployed at various scales.

Energy storage systems are uniquely capable of a variety of applications and uses. Like other NWS, energy storage can be used to defer distribution system upgrades and provide peak shaving benefits. In addition, can also provide demand charge reductions, and backup power in behind the meter applications.

Energy storage solutions can provide benefits to the distribution system in numerous ways, by providing multiple functions at different times of the day:

Active Power Functionality

Peak shaving - may be used to reduce exceptionally high load flows that likely occur only a handful of times per year and threaten to exceed thermal limits of lines or transformers either under all facilities in (N-0) or Contingency outage (N-1) conditions, as well as address voltage issues that might be caused at feeder ends.

Load Flattening Peak Shaving - may refer to the regular dispatch of energy during relative (typically daily) Substation of feeder load peaks. Operating the BESS in this way can:
 Reduce the range of loading on a given feeder
 Absorb energy during light-load periods

System Services – may be used to strategically dispatch the BESS to address (sub) transmission system needs
 Provide energy and power when they are more valuable,
 Limit ramp rates associated with the evening decrease of PV generation
 provide frequency control services

Reactive Power Functionality

It could be beneficial year-round (management or peak shaving should still be set as priority) to regulate substation power factor to help minimize losses as well as reduce the amount of reactive power to be sourced or absorbed by transmission. With modern inverter technology, reactive power support can be provided even while active power functionality is idling.

- BESS's method of dispatching reactive power aid in system voltage regulation by absorbing or injecting reactive power or idling as necessary.
- The ability of control voltage can help mitigate issues caused by the high penetration of DER, such as light load voltage rise depending on the location of the storage asset.
- The ability of the BESS to control voltage can mitigate post-contingency high voltage issues on the Transmission system that may be identified by ISO-NE.
- The ability of the BESS to control power factor may permit more improved compliance with ISO-NE Operating Procedure #17(Annual Load Power survey)

Operational Responsibility

One of the chief potential values of energy storage is its ability to provide timely energy on demand to the grid. This requires the eligibility of Eversource Energy to own and operate energy storage as a flexible source of power. It is necessary to own and operate energy storage to provide distribution grid management services, such as discharging the storage to offset peak load on a circuit or to manage voltage on a circuit. It is the responsibility of Eversource to have the ability to control the energy storage under defined conditions or time periods—and that the energy storage be available (i.e., sufficiently charged) to meet the grid performance need.

Processes for Identifying BESS Opportunities

Through analysis and assessments, specific distribution grid needs/constraints can be identified and be considered and addressed by a BESS option. Distribution System planning can include a variety of analysis such as:

- Forecasting of load growth analysis
  - Seasonal peak loads at substation distribution transformers
  - Spot loads
- Distribution feeder loading analysis
- Distribution system modeling and scenarios simulations
- Reliability assessments
  - Worst performing circuit analysis
- Utilization of traditional reliability indices
- Equipment/asset loading analysis

A traditional solution must be identified to be compared with the BESS option.
The BESS will be implemented if it meets the "least cost" solution for a grid need. If applied as a capacity deferral,

the transformer/line remaining life time expectancy must be greater than 10 years. A preliminary BESS gross estimate can be calculated by using the latest version of the National Renewable Energy Laboratory (NREL) U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Cost Benchmark. Refer to most recent table of US Utility-Scale Lithium-ion Standalone Storage Cost for Durations of 0.5-4 hours. To the selected $/kWh value, the feeder position installation cost (if applicable), must be added. To this total cost the ES Indirect Costs and the AFUDC must also be applied. Contact the respective Cost Estimating Department to get these costs

Distribution Battery Energy Storage Suitability

Eversource owned Energy Storage can be used to meet System Planning Standards for normal and contingency operations. When the BESS is applied inside or in the substation vicinity, consideration should be given to future substations expansions. The BESS should not restrict expected long-term substation upgrades.

Eversource uses the following suitability criteria to identify opportunities for storage Implementation:

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Capacity, Power Quality, and/or Resiliency.	
BESS	Storage is the least cost solution compared with traditional option	
	2-3 years Lead Time for small projects 3-5 years Lead Time for large projects	
Time-Horizon Suitability	BESS Minimum Life	5-12 years
	BESS Cycle Duration at nameplate power	1-4 hours
	Asset Condition (being relieved) Remaining Life Expectancy	≥ 5-12 year
Demand Suitability	Large Project	3-20 MW
	Small Project	1-2.5 MW

Table 5 - Opportunities for Storage Implementation Criteria

Note - For grid forming BESS applications short circuit ratio (short circuit of electric system at point of interconnection divided by size of BESS) should be greater than 1 at the minimum, optimal design is greater than 2. For grid following BESS applications short circuit ratio should be greater than 2, optimal design is greater than 3. BESS size solutions for Eversource areas with Low/Medium DER saturation and/or low peak shaving: 2.5MW/10MWh and 3.5MW/14MWh.

BESS distribution applications will consider utility system benefits such as:

- Avoided/Deferred distribution investments costs
    - Deferred distribution investment costs will be considered on a net present value basis
- Avoided energy and transmission costs
    - Yearly Capacity Peaks Reduction (Forward Capacity Market (FCM) costs
    - Monthly Regional and Local Network Services (RNS/LNS) Peak Reductions
- Clean Peaks Standards Certificates (MA only)

MA Only - Constructability of the BESS solution compared to the avoided conventional T&D upgrade.
If the BESS requires a substation expansion with extension of the fence line (which is an intensification of use), the BESS itself may trigger MDPU Chapter 40A review, whereas the conventional Substation upgrade (replacement of transformers in-kind with Larger banks) may not. This may be a factor that makes the conventional upgrade superior to the BESS implementation notwithstanding other apparent benefits.

Other components we need to consider for the Evaluation of a storage site vs. traditional upgrade.

- Aside from CapEx cost, BESS have significantly higher OpEx, so we should include expected maintenance and upkeep for the BESS over the study horizon as a net present value stream
- BESS energy losses, not sure where we account for those, but a 10MWh system that cycles once a day with an 80% roundtrip efficiency has a total annual energy consumption of 730 MWH. That needs to be paid for an accounted somehow
- Decommission and recycling. If it’s not already baked into the upfront project contract that can be a major cost factor.

Inverters Functions Applied to Eversource Options:

A three-phase inverter transforms the dc input into three-phase ac output. Inverters rely on their internal control logic to achieve the targeted functions and to support the grid stability. Inverters equipped with advanced functionality can provide grid support services such as frequency/voltage regulation (Volt-var, Volt-watt, Fixed power factor (watt-var), hertz-watt, etc.)

<u>Reactive power applications</u> including Volt/VAR, independent reactive power (Q) dispatched output, and PF control

- The goal is to use inverters as a resource in distribution circuit voltage profile management, power quality, and power factor management
- Both autonomous and centrally controlled applications are of interest
- Implementations may include an inverter Q response to a local and/or remote measurement
- With modern inverters and dependent on the control option, Q response is not limited to times of active power activity.

Islanding

- The goal is to provide enhanced resiliency to customers by providing a back-up power supply during a loss of the normal electrical service
- Near-term anticipated islanding use cases have the following characteristics:
    - The ESS will island a 3-phase portion of a distribution circuit
    - Phase imbalance may be significant
    - The ESS inverter is required to provide grid-forming functions including voltage and frequency regulation
    - The island will not include other sources of generation, load control, or a central microgrid controller
    - The ESS will coordinate with circuit management devices such as reclosers and with a distribution control center
    - May be implemented as seamless transfer, or may require picking up cold load
- Future islanding applications, in addition to the above, have the following characteristics:
    - Require coordination with central microgrid controller
    - Require coordination with diverse other resources including solar, cogeneration facilities, diesel generators, flexible load
    - May involve significant phase imbalance of load and other generation resources

- Frequency response
    - The goal is to explore ability of inverters to participate in autonomous frequency response

- Inverter should have an autonomous response to locally measured frequency Phase Balancing operation
    - 3 phase inverters are typically set up as three single phase inverters with a joint DC bank allowing theoretical, and practical control of each phase individually.
    - Charging and discharging of active power to balance phases
    - Generation or consumption of reactive power to balance power factor and support individual phase voltages

- Eversource-owned utility scale BESS can also:
    - Participate in ISO-NE System Blackstart
    - Participate in other ISO-NE markets such as frequency regulation.

Distribution System Potential Benefits from the BESS/Smart Inverter

- Capacity Deferral—Storage can help delay a capacity investment to reduce expected present value costs or gather additional information and preserve options regarding the timing, nature, and scale of the required investment.
- Backup Supply—Storage can enable a Customer or group of Customers to maintain some or all electric service when power is not available from the grid.
- Remote Loads—Storage can be deployed in locations where significant investment would be required to provide service to the Customer and/or meet reliability requirements. This may include support for various remote EV charging scenarios (e.g., fast charging, fleet charging, transit charging) to smooth spikes in demand.
- Buffering—Storage can continuously and automatically offset and smooth changes in real power demand and supply from other DERs.
- CVO—Storage can assist in actively controlling distribution voltage, in most circumstances, to achieve energy and demand savings/reductions.
- Island—In an Island mode, zones, or circuits are capable of operating autonomously or collaboratively to optimize their operation based on system conditions. Storage can help balance demand and supply in a specific zone/circuit when disconnected from other portions of the grid system.
- Power Quality—Storage can help maintain the wave form in an alternating current (AC) power system that is necessary to ensure reliable and efficient operation of the grid and Customer equipment.
- Congestion Relief—Storage can help mitigate distribution congestion and enable more efficient power transfer by increasing demand upstream of a constraint or by supplying energy downstream of a constraint.
- Ramping—Storage can help address rapid changes in supply and/or demand over various time periods, from several dispatch intervals to several hours.
- System Efficiency—Storage can make load factor improvements by shifting demand from peak to off-peak periods.
- Topology Optimization—Storage can provide power or reserves such that the system can be reconfigured while continuing to meet reliability requirements.

System	***Capacity***	***Grid/Ancillary Services***	***Reliability***
Distribution System	Capacity Deferral Backup Supply Remote Loads Buffering CVO Congestion Relief Topology Optimization Backup Supply	Power Quality System Efficiency	Island
Bulk System	Capacity Deferral Buffering Congestion Relief Backup Supply	Power Quality System Efficiency	Ramping

2.12.Network Criteria

Downton areas of large cities are characterized by high power demands and increased customer density. Additionally, since most of the financial and commercial businesses are typically located in downtown areas, there are often strict requirements for uninterruptable power supply and power quality.

Full Secondary Network load areas, which are typically High Load Density, are defined as those in which both the low voltage secondary grid and customer spot networks installations are supplied by distribution underground network feeders that are connected to network bulk distribution substations. By this definition, both the supply feeders and the substations are designed and operated to meet the Reliability Requirements of the Secondary Network System.

Partial Secondary Network load areas are defined as those in which the low voltage secondary grid and individual customers spot networks installations are supplied by a combination of underground and overhead network feeders, but both the feeders and/or the substations are not designed to meet the reliability requirements of the Secondary Network System. Low and Medium load density areas are typically supplied via Partial Secondary Network systems.

Full Secondary Network System Reliability Requirements:

The objective of a secondary network is to interconnect feeders and transformers to form a consistent and well-diversified intermesh through the impedance of the low-voltage grid of mains and transformers. Feeders are connected to network transformers whose low voltage cables connect to a low-voltage secondary grid via network protector devices. The Eversource Full Secondary Network Systems is designed for N-1 Contingency Criteria at the substation level. The system is designed so that the loss of one distribution feeder does not result in customer interruptions, unsatisfactory customer voltages, or secondary cable overloads.

To maintain this level of reliability, the following design practices are implemented in Secondary Network load areas:

- At the secondary low voltage grid level, it is necessary to install a diversified intermesh with proper number, size, and capacity of transformers and secondary mains. This ensures that secondary equipment load levels remain under the required normal and emergency threshold for any combination of N-1 contingency.
- At the feeder level, it is necessary to use proper diversity when supply network transformers so that a single contingency N-1 event or transformer outage will have the minimum impact on secondary mains and nearby transformer loading.
- At the network level, to maintain proper feeder diversity only a certain number and combination of feeders are installed in the same conduit system and allowed to supply the same local areas or spot network installations. This prevents a single manhole or conduit section failure to result in secondary main overloads, transformer overloads, and/or customer outages.
- At the substation level, to maintain proper bus diversity feeder bus arrangement in network stations should be designed so that a bus section outage will have minimum impact on feeder loading. When designing or arranging distribution network feeders, it is recommended to connect unrelated feeders to each bus sections. This ensures that feeders supplying the same local areas a supplied from different bus sections.

Network Substation Supplying Full Secondary Network Load Areas:

Distribution Bulk Substation supplying network areas shall be designed so that each distribution bus has a minimum of two means of supply that are always connected in a parallel. In this context, the primary supply is provided by connection to the secondary winding of a bulk distribution transformer, and secondary supply is provided by connecting to a normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different Bulk Distribution Transformer.

For a Standard Substation Ring Bus configuration, each distribution bus has three means of supply that are always connected in parallel. The primary supply is provided by connection to the secondary winding of a bulk distribution transformer, and secondary supply is provided by connecting to normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different bulk distribution transformer.

Substations supplying Full Secondary Networks are operate with all transformers in service and all transformers connected in parallel so that the loss of transformers resulting from a Single Contingency event (loss of transmission or transformer) does not result in interrupted customers service.

The responsibility for determining and ensuring that network transformers, secondary mains, and network feeder loadings are within the design criteria for normal and emergency conditions rests with Distribution Engineering. The responsibility for determining and ensuring that the substation, inside plant distribution equipment, and inside plant cable as well as Distribution feeder is within design criteria for normal and emergency conditions rests with Distribution System Planning.

2.13. Distributed Energy Resources Criteria.

Detailed requirements relative to the safety, performance, reliability, operation, design, protection, testing and maintenance of the DER's interconnecting facility are provided under reference document "Information and Technical Requirements for the Interconnection of DER".

Eversource has established administrative processes for interconnecting all types and sizes of DER installations. As the level of customer and developer interest advances beyond the initial inquiry phase, a formal review process takes place in which the potential impact of a given site on the Eversource EPS is reviewed. This review may include the execution of formal study agreements and may result in general and specific requirements for certain design aspects of the DER. These requirements typically include electrical protection and control design and configuration, interface transformer configuration, required modifications to local Eversource facilities, metering and supervisory control and data acquisition ("SCADA") requirements, and in some cases operating constraints for the proposed DER.

3. Rating Criteria

3.1. Feeder Rating

The Eversource distribution feeder ratings are determined by the Synergi power flow program. The method outlined in this specification is incorporated into the Synergi program.

Distribution Feeder Rating

- The normal rating of a distribution feeder is the load in amperes that the feeder can carry for a 24-hour load cycle under system intact (N-0) conditions without exceeding the normal rating for Substation getaway cable, underground cable, aerial cable, overhead wire or any equipment in series on the feeder.
- The emergency rating of a distribution feeder is the maximum load in amperes that the feeder can carry under contingency (N-1) conditions without exceeding the emergency ratings for Substation getaway, underground cable, aerial cable, overhead wire or equipment in series for 24 hours.

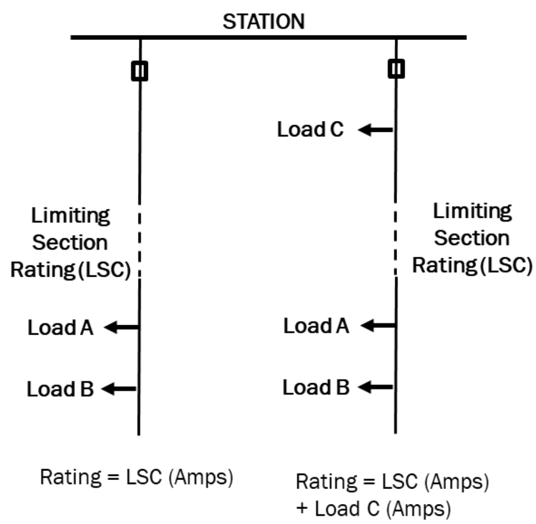


Figure 2 - Feeder Ratings and Limiting Section

Procedure for Rating Distribution Feeders:
The procedure for rating distribution feeders at the source involves 3 steps
1 - Determine the feeder rating as limited by Substation getaway cables, by using an Eversource approved rating program, and the feeder trip set point calculated by the Protection Department, which should include the rating of the Substation feeder breaker.
2 - Calculate the feeder rating as determined by the most limited section of underground cable, aerial cable or overhead wire, using the cable and wire thermal loading criteria provided in Section 2.3.1.
3 - Establish the feeder rating as the values of 1 and 2 whichever is lower.

Distribution Normal Rating

Radial Feeder

The normal rating is the normal rating of the cable or wire ahead of all load, or it is the normal rating of a limiting cable or wire section plus all the load that is normally supplied ahead of the limiting section, whichever is lower. The emergency rating is the emergency rating of the cable or wire ahead of all load, or it is the emergency rating of a limiting cable or wire section plus the total of an appropriate combination of emergency and normal loads ahead of the limiting section, whichever is lower. The appropriate combination of emergency and normal loads ahead of the limiting section that gives the lowest emergency rating is used.

Loop Feeders

The normal rating of each side of the loop is determined as for Distribution Radial Feeder above by considering all normal loads from the source end of the loop to the electrical midpoint of the loop. The emergency rating of each side of the loop is the emergency rating of the cable or wire between the source and the first load, or it is the emergency rating determined by a limiting cable or wire section on the basis that the loop is open at one end between the source and the first load.

Feeders with co-Generation

Cogeneration customers supply a portion of their total load with their own generators. Co-generation installed on a distribution feeder reduces the apparent load on the respective feeder. When determining the rating on a feeder with co-generation, any load supplied by co-generation should be added to the monitored load on the feeder. The reason for this policy is that co-generation possibly may not be connected to the feeder during the summer peak period and the company must supply all the load of the co-generation customer from existing facilities. Additional assessments of historic operational history, as well as contractual commitments from the Generation Owner to Eversource, are conducted where large co-generation (relative to the identified thermal overload) may sufficiently mitigate thermal constraints.

Distribution Emergency Ratings

Radial Feeder

The emergency rating is the emergency rating of the cable or wire ahead of all load, or of a limiting cable or wire section plus all load that is normally supplied ahead of the limiting cable or wire section plus load that has been identified as Required Emergency Switching ahead of the limiting section, whichever is lower. Required Emergency Switching shall be identified for every radial circuit by Engineering and Operations. It includes the largest load transfer expected on a radial feeder to support other connected feeders during emergency operations.

Loop Feeders with Automatic/Manual Ties

The emergency rating of each feeder is determined for each single loop feeder by assuming the automatic midpoint field switch is closed and the entire normal load on the two feeders is supplied from one substation. Consider the possibility that the loop feeder, with the automatic field switch open, also supplies load to one or more emergency tie points (Required Emergency Switching), or feeds load through to another substation. The emergency rating that is calculated by accounting for the largest emergency tie in the feeders should be used.

3.2. Rating of Feeder Supplying Secondary Networks

Network feeder cables have Normal and Long-Term Emergency ratings for both summer winter months. The ratings are contained in a table of cable ratings compiled for use in rating 15kV and 25kV cables, and they take into account the cable size and the number of ducts occupied in a given duct bank. In the network area, the ratings are applied conservatively to account for the proximity of other facilities in the street, including non-electric facilities that can contribute additional heat to the network feeder cables.

3.3. Transformer Rating

Bulk Distribution Transformers are integral to the electric distribution system and are large capital investments with long lead time. The cost of premature/unexpected failure of these assets can amount to several times the initial cost of the transformer. The cost of failure not only includes refurbishment or replacement of the transformer, but also costs associated with clean-up, loss of revenue and possible deterioration in the quality of service to customers. It is important to Eversource that the ratings for bulk distribution transformers are calculated accurately and that the results are well documented.

Eversource follows the methodology in SYSPLAN 008 for calculating Bulk Distribution Transformers. This procedure is based on IEEE C57.91-2011 and IEEE C57.12.00-2015.

The process in SYSPLAN 008 was developed in a collaborative effort between the Eversource System Planning, Substation Design Engineering, and Substation Technical Engineering Departments and relies on input from Industry Standards, ISO-NE Planning Procedures, and Eversource operating experience.

Transformer Rating Categories

ISO-NE PP-7 section 2.3 requires transmission owners in New England to provide four categories of load carrying ratings: Normal, Long Time Emergency (LTE), Short-Time Emergency (STE) and Drastic Action Limit (DAL). Per ISO-NE PP-7 Appendix D, since operation of load-serving transformers does not impact the high voltage transmission system, the transformer owner may determine the criteria for rating a load-serving transformer. Also, the duration associated with LTE, STE and DAL limits may vary from the durations in PP7 Section 2.3. Therefore, Eversource utilizes the following time durations for these four categories of ratings:

- Normal Ratings – Continuous
- Winter LTE (W LTE) - 4 hours
- Summer LTE (S LTE) - 12 hours
- Winter STE (W STE) - *30 minutes
- Summer STE (S STE) - *30 minutes
- Drastic Action Limits – *DAL is equal to the STE for Summer and Winter ratings)

*Note - For operational practicality purposes, there is not enough time for an operator to respond when a transformer is loaded at or above STE. Hence, Eversource generally sets the STE as a 30-minute rating as opposed to the guideline of 15-minutes and sets the DAL equal to the STE rating.

Substation Rating:

To maximize the substation output, the Standard Bulk Distribution Substation shall be designed such that the limiting element is the substation transformer. Therefore, the Substation Normal and Emergency Ratings shall be defined by the Normal, LTE and STE ratings of the smallest transformer(s).

For a Substation where the transformer(s) is not the limiting element, the rating of the substation as a whole should be calculated based on the limiting factor which includes but is not limited to: gateway duct bank cable, switchgear/bus, breakers, disconnect switches, and transmission lines. Distribution System Planning should verify the Substation limiting element against the NX-9B form supplied by Substation Engineering.

Substation Firm and Load Carrying Capability:

In calculating the rating of a bulk distribution substations, it is important to consider the loss of the largest element during an N-1 contingency condition in addition to the load that can be transferred out of the station post contingency. Firm and Load Carrying Capability (LCC) ratings are used to account for both of these limits:

- Firm Capacity is defined as the total LTE rating of the remaining transformer(s) after the loss of the largest transformer, refer to Section 6.1 for full definition.
- LCC is defined as the Firm Capacity plus Distribution Transfer Switching Capacity
    - Distribution Transfer Switching Capacity is calculated by assuming successful transfers of load to other stations is completed within 30 minutes

The 30-minute limit used for Distribution Transfer Capacity is driven by constraints under various operational scenarios. Below is a list of steps to be considered following a contingency:

NOTE: Dispatcher initiated load transfers (using distribution automation capabilities, manual switching is not used for this purpose) must be available to lower transformer winding loads to below the LTE rating, within the time frame given below.

When distribution load transfers are credited for reducing transformer winding loads to below the LTE rating, the following time frames shall be used:

- The initial post-event assessment period for Dispatchers to identify/assess the event shall be 10 minutes.
- The time to implement each load transfer is 5 minutes.
- All load transfers are sequential, when more than one is needed:
  - Two transfers take 10 minutes
  - Three transfers take 15 minutes
  - Etc.
- Where possible, there shall be at least one extra load transfer available for Dispatchers to use. This shall be available for use in the event that one of the primary load transfers cannot be accomplished.

Bulk Distribution Transformer(s) that provide secondary supply to other transformers under contingency conditions, shall be within LTE loading criteria for the first load cycle following an event. Additional distribution switching (remotely controlled) and/or a mobile transformer shall be available to lower transformer winding loads to the normal rating or below.

Additional distribution switching via loop scheme used in lowering the transformer to below normal rating shall be limited to those that can be restored to normal configuration within 24 hours or a mobile position connection shall be installed at the substation. A mobile installation will be implemented when problems will require multiple load cycles to be resolved. Substations with space or connection constraints that prohibit the installation of a mobile transformers shall be rated up to the nameplate of the remaining transformers after the loss of the largest transformer.

Substations Serving Major Secondary Network Systems

Because of the nature of secondary network loads, there is no transfer switching capability with other substations. This results in the substation capability being equal to the LTE rating of the smallest remaining transformer(s) and that STE/DAL ratings cannot be applied because there is no transfer capability to relieve transformer winding loads.

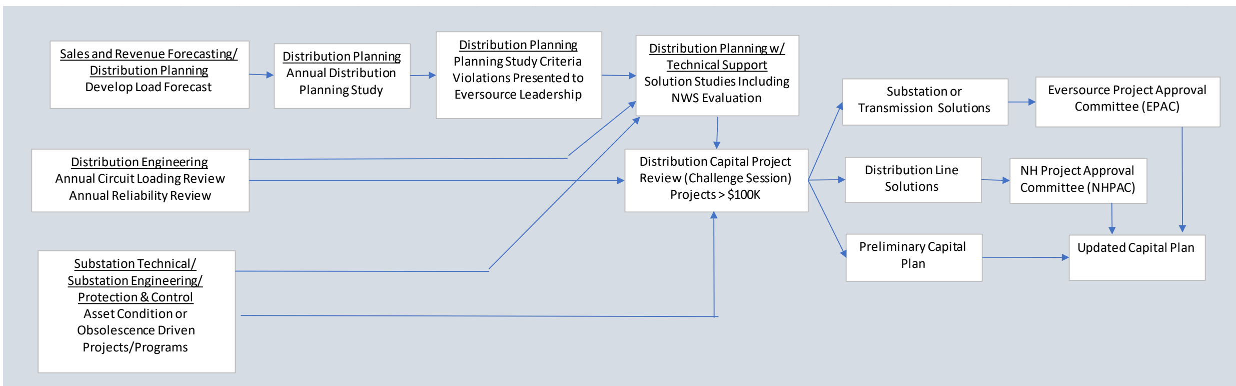
4. Planning Methodology

4.1. Introduction

Distributions System Planning is a fundamental function of the utility to provide reliable and cost-effective electric service to our customers. System Planning objective is centered around the goal of providing safe and reliable service to our customers. Eversource is at the forefront of integrating System Planning with a comprehensive modeling and Probabilistic Forecast process that integrates new technologies as they mature, and penetration levels increase. The goal is to integrate new technologies in a manner that enhances or maintains grid reliability. Although traditional system upgrade solutions have proven effective, as DER penetration levels increase, consideration should be given in the evaluation of solutions to avoid compromising safety, cost effectiveness, and reliability.

4.2. Process Map

Project Initiation Process



4.3. Model Development

Distribution System Planning develops regional planning models which are used to perform capacity, reliability, and power quality studies for bulk distribution substations, including 10-year substation capacity plans. This section describes the model development process applicable to all distribution planning departments using the Synergi Electric software.

The yearly model development process starts after the summer period with the first October of the Observed Year. Seasonal 24-hour load profiles are extracted from PI and analyzed for accuracy. Hereby two peak conditions can be identified:

> **I - Peak Net Load Day**: The day with the highest peak net load measured at the substation. Because this load is measured from the substation meters it includes the impact (load reduction) of generation that is in service during that day.
> **II - Peak Gross Load Day**: The day representing the highest gross demand at the substation. This load is calculated by using the measurement at the substation and adding the contribution of generation output (front of the meter) and estimates (behind the meter).

NOTE: The Peak Gross Load Day is important for the 10-year system plan. As a result, when defining that day, it cannot simply be done by finding the highest loading day measured at the substation. A more comprehensive search must be conducted in correlation with generation (including Distributed Energy Resource – DER). When insufficient load/generation data is available to determine the Peak Gross Load Day for the year, a good workaround is to use the Peak Net Load Day data and add the generation output (front of the meter) and estimated generation (behind the meter) to obtain the Summer Peak Gross Load Day.

The same analysis is to be done for

I - Minimum Net Load Day: The day with minimum net load measured at the substation.
II - Minimum Gross Load Day: The day representing the minimum gross demand at the substation.

Based on the substation load profile measured for the Observed Year and the trend in historical peak load, Distribution System Planning determines which ones should be analyzed as non-coincident or coincident with the ISO NE system peak, the official peak substation day, and the actual peak time. When possible, a peak day (or time) with normal system conditions is selected, and days with outages of substation transformers, multiple distribution feeders, or transmission lines should be avoided. The final Peak Gross Load for each Substation is recorded and provided to the Forecasting group to start the development of the company's 10-year load forecast. When required, the load profile is adjusted to account for abnormal conditions, including but not limited to: emergency load transfers, system reconfiguration, contingency conditions, and generation status. This yields the system model and load condition that are expected under normal configuration.

In parallel with the effort of reviewing the Peak 24-hour load profile for each substation, distribution system data extraction/import into the Synergi application is completed using the established **Peak Gross Load Day** as a framework. Ideally, the connectivity model that closely matches the actual circuit configuration during the peak day shall be extracted from GIS and made available in Synergi, ensuring a more accurate planning model.

Based on the availability and accuracy of the extracted GIS and Synergi data, distribution Substation capacity analysis is completed using one of the following methods:

- For substations with limited data that result in a non-converging model or load flow results not reflecting real peak load conditions, as a comparison of actual substation measured data during the peak load day, a 10-year capacity analysis based on hand calculation of capacity is acceptable.
- If data extraction results in a converging load flow model reflecting real peak-time conditions but not accurate 24-hour load conditions, complete and use only the peak-time load data and model for completing the substation 10-year capacity analysis.
- If data extraction results in a converging 24-hour load data model, complete and use a 24-hour model for completing the substation 10-year capacity analysis.

When developing 10-year substation capacity plans, each substation <u>can</u> be considered under a total of two (2), or where applicable, four (4) different planning models. These planning models should align with the studies conducted for DER interconnection studies by the DER Planning Group.

I - Summer or Shoulder
a - Minimum Load Planning Models
b - Peak Load Planning Models
II - Winter Planning Models:
a - Winter Peak Load Planning Model
b - Winter Minimum Load Planning Model

NOTE: Distribution System Planning will determine the scenario(s), Summer, Shoulder, and/or Winter, to be analyzed for each station depending on the station historical load profile.

To expedite the yearly distribution system model building process and account for substation normal and N-1 conditions, Distribution System Planning will define and maintain a list of models and the substations included in each model. At the minimum, a complete planning model shall include:

- All the distribution bulk transformers in each substation
- Transmission source impedance at the high side of the substation transformers based on the normal configuration of the Transmission System.
- Station bus with associated bus tie breakers and feeder breakers
- Full representation of all distribution feeder backbone sections that are used to provide load carrying capability (LCC)
- Non-bulk substations may be modeled as needed up to the secondary side of the transformers, including the distribution ties between substations, to provide additional details.

4.4. Gross Load Model and DER Forecast

With Eversource's Service Territory experiencing a large increase in DER adoption the development of Gross Load Models is extremely importance.

$$P_{Gross}(t) = P_{net}(t) + P_{DER}(t)$$

Hereby $P_{net}(t)$ represents the 15 min time series values (where available) in MW measured at the substation and collected from the PI database.

NOTE: Where 15 min data is not available, hourly interval simulations are acceptable

CAUTION: In a multi transformer station ensure that that DERs are accurately assigned to the circuit, and transformer, that is feeding them.

The following figure highlights the difference between a clear sky irradiance profile and the actual measured profile during a peak day sample.

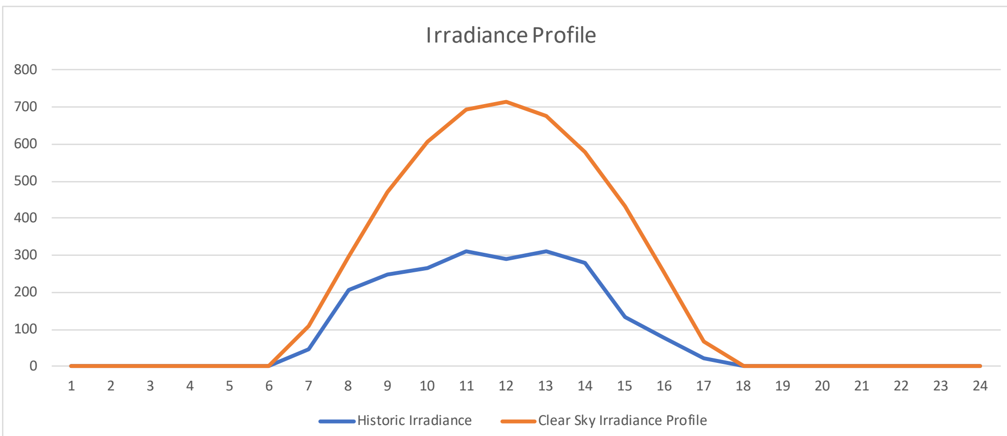


Figure 3: Clear sky and actual irradiance profile

NOTE: Irradiance data is given in W/m2. Solar ratings are typically given at 1000W/m2. As a result, the actual output is:

$$P_{Output} = P_{Rating} * \frac{\epsilon_{irradiance}}{1000\,\frac{W}{m^2}}$$

$P_{DER}(t)$ represents the power generated by the DER the at time point.

Type of DER	Methodology
Behind-The-Meter solar (BTM)	Multiply the installed DER nameplate capacity by the historic irradiance data to receive the estimated output at the specific data and time. If no irradiance data is available, use the nearby PI reading of a large solar installation.
In front of the meter solar	Utilize the PI recorded data if available, otherwise apply same process as for BTM solar.

Table 6: Solar Methodology

The following highlights an example for a net and gross load model with solar generation. This gross load model allows the identification of the Gross Load Peak and Gross Load Minimum day.

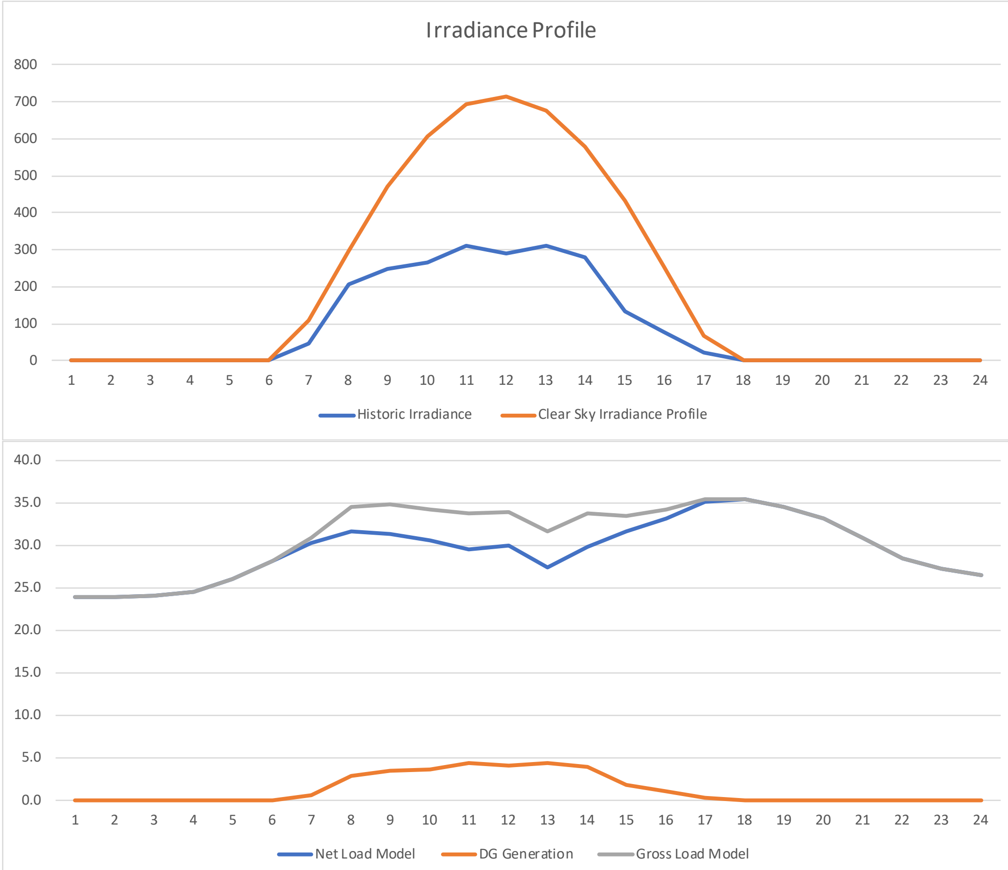


Figure 4: Gross and Net Load Profiles with DER output

Once the DG is backed out of the net readings and the gross load time series determined, the peak gross day can be evaluated. When applying forecasts to any gross model, the following steps are to be taken.

When reapplying the forecast data to the Gross Model, two observations can be made depending on if the forecasts are applied to the gross peak or gross minimum:

1) - Peak Forecast Load Model

When forecasting with the peak load model, the objective is to scale and build the system for heavy load conditions. This model finds application in all systems where there is not enough DG to be driving capacity investments. As such, high load conditions and low DG conditions are assumed.

$$P_{Peak\_forecast}(t) = P_{gross\_max}(t) - \left[P_{Installed}(t) + P_{Forecasted_{10th}}(t)\right] * \varepsilon_{10\%}$$

Where

P_{gross_max} = Gross maximum load
$P_{Installed} * \varepsilon_{10\%}$ = 10% of seasonal clear sky profile
$P_{Forecasted} * \varepsilon_{10\%}$ = 10th percentile of solar adoption

Steps

1 - Determine the gross peak load day (e.g. August 4th
2 - Determine the corresponding clear sky profile
3 - Determine the 10% profile of the corresponding clear sky profile
4 - Apply the 10% profile to all installed DG
5 - Add in 10th percentile DG adoption

6 - Apply the 10% profile to all newly adopted DG

2) - Minimum Forecast Model

The minimum model serves as the planning model for high DG impact systems where the largest concern is around low load conditions meeting high DG output. As such, it is forecasted with low load growth and high DG adoption and output.

$$P_{Min\_forecast}(t) = P_{gross\_min}(t) - \left[P_{Installed}(t) + P_{Forecasted_{90th}}(t)\right] * \varepsilon_{100\%}$$

Where

P_{gross_max} = Gross minimum load
$P_{Installed}$ * $\varepsilon_{10\%}$ = 10% of seasonal clear sky profile
$P_{Forecasted}$ * $\varepsilon_{10\%}$ = 10th percentile of solar adoption

Steps

1 - Determine the gross minimum load day (e.g. March 4th
2 - Determine the corresponding clear sky profile
3 - Apply the clear sky profile to all installed DG
4 - Add in 10th percentile DG adoption
5 - Apply the clear sky profile to all newly adopted DG

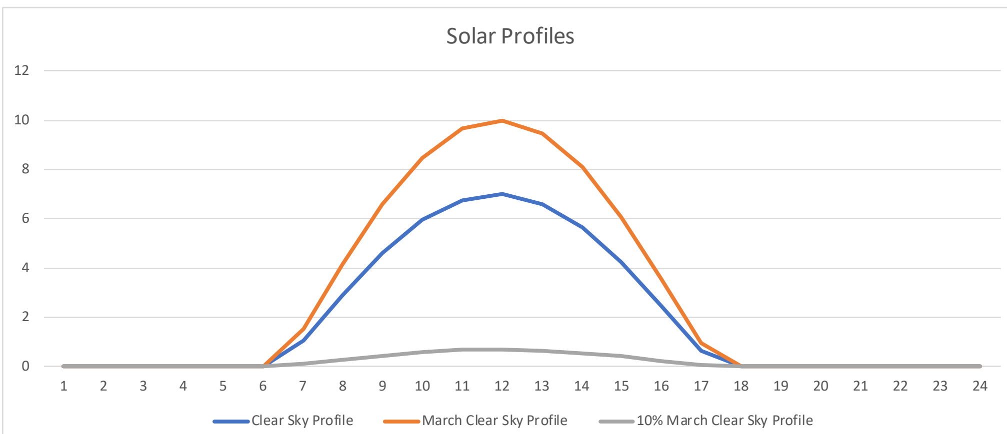


Figure 5: Scaled Forecast Profiles

4.4.1. Scenario Forecasts

Eversource historically produces both a 'normal' and an 'extreme' peak load forecast for each operating company. The normal peak load is based on average historical weather data, and the extreme peak is based on the 90th percentile of that historical weather data. The extreme peak is also referred to as a 90/10 forecast and it assumes a 10% chance that the peak load would be exceeded. Put another way, the forecast will be exceeded on average only once every 10 years.

As part of the Company's substation planning process, the Company develops Probabilistic Based Forecasts for the purposes of testing and evaluating the performance of the system and assessing the need for substation capacity upgrades. Hereby an individual set of forecasts can be generated for each substation to reflect locational specific factors.

Forecast Component	Description	Responsibility	Type
Trend ε_{Trend}	Historical and forecast economic data are procured by an international economic	Revenue Forecasting	Proportional Scaling Forecast: Scales existing loads proportionally with forecasted trend. Applies to all 24-hour time intervals

Forecast Component	Description	Responsibility	Type
	consulting company.		Capacity Data **%** of last peak day
DG Adoption $P_{DG_{Adoption}}$	Produces a probability distribution of total DG adoption on the studied station. Depending on forecast type, certain percentiles are selected	System Planning	Probabilistic Forecast: Capacity Data in **MW** by type of DG
DG Queue $P_{DG_{Queue}}$	All previously known DG interconnections that have been requested	DER Planning	Capacity Data in **MW** by unit including location
DG Output $\varepsilon_{DG_{Output}}(t)$	Firm contribution of DG assets to peak. Using a probabilistic model, the firm contribution of any form of DG to system peak is calculated and later applied to forecasted, in queue, and presently available installed DG capacity	System Planning	Probabilistic Forecast: Produces percentiles of forecasted correlation between load peak and DG output. Time Series Data in **%** of installed by type of DG
EV Adoption $P_{EV_{Adoption}}$	Produces a probability distribution of total EV charging capacity adoption on the studied station. Depending on forecast type, certain percentiles are selected	System Planning	Probabilistic Forecast: Number of EV charging stations Capacity Data in **MW**
EV Profile $\varepsilon_{EV_{Profile}}(t)$	Produces a probabilistic load shape for EV charging based on expected travel patterns, charging durations, vehicle types and available charging infrastructure.	System Planning	Probabilistic Forecast: Load shapes can be selected based on observed percentile. Requires a forecast on number of electric vehicles Time Series Data in **%** of installed
Energy Efficiency EE	EE Trend forecast showing the annual and cumulative reduction expected through energy efficiency measures	Energy Efficiency Group	Proportionally Scaling Forecast: Reduces all loads proportionally to peak hour at any time point of the scenario Capacity Data in **MW** (applied proportionally)
Sector Conversion $P_{Conversion}(t)$	Linear forecast based on assumptions of gas to electricity conversion. Time series load profile derived from gas profiles	System Planning	Time Series Data in **MW**
New Business Growth Queue $P_{Step_{Queue}}(t)$	All previously known New Business Growth interconnections that have been requested	System Planning	Capacity Data in **MW** by unit including location
New Business Growth Development $P_{Step}(t)$	Probabilistic forecast predicting the probability of total new New Business Growth additions in MW during peak load hour.	System Planning	Proportionally Scaling Forecast: Increases all loads proportionally to peak hour at any time point of the scenario Capacity Data in **MW** (applied proportionally)

Forecast Component	Description	Responsibility	Type
Capacity Reserves $P_{Reserve}(t)$	Represents known co-generation units that run continuously. Customer or utility sited. Accounts for failure of the largest of such units on the observed station[5]	System Planning	Time Series Data in **MW**

Table 7- Forecast Components

Hereby $P_{PeakLoad}(t)$ represents last year's season peak load day (24 hours, 15 min intervals) and $P_{DG_{Installed}}$ represents <u>all currently installed capacity</u> (by type of DG) on the studied station.

$$P_{PeakForecast} = \left[P_{PeakLoad} * \varepsilon_{Trend} * \left[1 + \frac{\left(P_{Step} + P_{Step_{Queue}} + EE\right)}{\max[P_{PeakLoad}]}\right]\right] + P_{Reserve} - \left[\sum_{All\ DG}\left(P_{DG_{Installed}} + P_{DG_{Adoption}} + P_{DG_{Queue}}\right) * \varepsilon_{DG_{Output}}\right] + \left(P_{EV_{Adoption}} * \varepsilon_{EV_{Profile}}\right) + P_{Conversion}$$

As well as $P_{MinLoad}$ represents last year's season minim load day (24 hours, 15 min intervals)

$$P_{MinForecast} = \left[P_{MinLoad} * \varepsilon_{Trend} * \left[1 + \frac{\left(P_{Step} + P_{Step_{Queue}} + EE\right)}{\max[P_{MinLoad}]}\right]\right] + P_{Reserve} - \left[\sum_{All\ DG}\left(P_{DG_{Installed}} + P_{DG_{Adoption}} + P_{DG_{Queue}}\right) * \varepsilon_{DG_{Output}}\right] + \left(P_{EV_{Adoption}} * \varepsilon_{EV_{Profile}}\right) + P_{Conversion}$$

NOTE: If specific forecasts are not available for a substation, they can be assumed to be not relevant to the study.

Each forecast that is impacted by seasonality (Sector Conversion, EV Profile, DG Output, and Trend) are provided by season to allow planners to select the corresponding forecast depending on the scenario he/she is studying for a specific station.

The following shows an example of two scenario forecasts and their respective extreme versions.

[5] In compliance with the Department's guidance in D.P.U. 13-86, the Company has amended its load forecasting methodology both to align with ISO-NE and to change how it reconstitutes loads for distributed generation. The Company no longer reconstitutes loads for distributed generation units larger than 5 MW, unless those customers are on Standby Delivery Service (also called Reserve Capacity in CT). For Customers on Standby Delivery Service, the company is obligated to be: "standing ready to provide delivery of electricity supply to replace the portion of the Customer's internal electric load normally supplied by the Generation Units be unable to provide all, or a portion of, the expected electricity supply." 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 or not. To reflect this obligation, forecasted loads have been reconstituted for the portion of load that was served by the Generation Units.

Forecast Component	Load Driven Forecast Model (Extreme)	Generation Driven Forecast Model (Extreme)
Baseline	Peak Gross Load Model	Minimum Gross Load Model
Trend ε_{Trend}	Baseline (90^{th} percentile)	Baseline (10^{th} percentile)
DG Queue $P_{DG_{Queue}}$	As Reported	As Reported
DG Adoption $P_{DG_{Adoption}}$	10^{th} percentile (-2-Sigma)	90^{th} percentile (2 Sigma)
DG Output $\varepsilon_{DG_{Output}}(t)$	10% of clear sky	100% of clear sky
EV Adoption $P_{EV_{Adoption}}$	90^{th} percentile (2-Sigma)	10^{th} percentile (-2 Sigma)
EV Profile $\varepsilon_{EV_{Profile}}(t)$	90^{th} percentile (2-Sigma)	10^{th} percentile (-2 Sigma)
Energy Efficiency EE	10^{th} percentile (-2-Sigma)	90^{th} percentile (2 Sigma)
Sector Conversion $P_{Conversion}(t)$	90^{th} percentile (2-Sigma)	10^{th} percentile (-2 Sigma)
New Business Growth Development P_{Step}	90^{th} percentile (2-Sigma)	10^{th} percentile (-2 Sigma)
New Business Growth Queue $P_{Step_{Queue}}(t)$	As Reported	As Reported
Capacity Reserves $P_{Reserve}(t)$	As Reported	As Reported

Table 8- Forecast Scenario Extreme Versions

NOTE: The distribution planner may use multiple scenarios from the available forecast data in addition to the above-mentioned scenario forecasts. Additional scenarios can be created by mixing the respective forecast components based on local knowledge.

4.4.2. Modeling Forecasts

When modeling the Probabilistic forecasts in the Approved Distribution Model, some forecast projections are applied at the substation level and equally distributed to all line segments using load allocation and some forecast projections are applied at individual feeder locations.

Forecasted Resource	Approach in Synergi
New Business Growth Forecast	Equally distributed load increase across all line segments
New Business Growth Queue	Placed at reported location
DG Forecast	Equally distributed load decrease by profile
DG Queue	Placed at reported location
EV	Equally distributed load increase across all line segments with charging profile
DG Output	Applied to the respective DG clear sky profiles
Sector Conversion	Equally distributed load increase across all line segments
Energy Efficiency	Equally distributed load decrease across all line segments

Table 9- Forecast Resources

For load allocation, allocation by annual consumption data is the preferred method where the data supports such an approach. Otherwise, allocation by installed capacity is to be used.

4.5. Planning Model

4.5.1. Base Case Planning Model

Base Case Planning models are validated against the actual measured station load of the Observed Year. Based on the configuration of the distribution system, load transfer capability, and distributed generation size and location, a Based Case Planning Model could be defined as just one station, or multiple stations could be combined as one model. Combining interconnected stations, that depend on each other during contingency conditions, into one model facilitates the analysis of N-1 contingencies in the distribution system and the impact that these contingencies have on system operation.

Due to the validation requirements, Base Case Planning Models are finalized after the peak summer day is established. Once validated, the 10-year probabilistic load forecast can be integrated, and capital projects can be studied and proposed for the next 10 years. Projects not meeting a required 12 months minimum timeline from the completion of the model shall be analyzed using the prior year Base Case Models.

4.5.2. Peak and Minimum Load Planning Models

These are developed from the Base Case to represent the peak and minimum load day conditions for the specific station or group of stations that make up the model. These models include the 10-Year Load Forecast, planned DER, and Planned Reinforcements in the 5-year capital plan.

Probabilistic Forecast
If a 10-year Probabilistic Forecast will be made available in the future, it is integrated into the model to analyze the peak load conditions for the next 10 years.

By adjusting the individual Forecast Components that make up the Probabilistic Forecast it is possible to account for existing business-as-usual planning scenarios, as well as future local and/or state policy and technologies changes with the potential to alter the electric load forecast.

Standard Forecast
The Standard Forecast considers the possibility of different growth rates based on historical trend and penetration of new technologies, but it does not consider consumer behavior or local/state policies and technology changes driving the use and adoption of these technologies, which should be studied using a Probabilistic Planning Approach. Nevertheless, if insufficient data is available to develop a Probabilistic Forecast, the Peak and Minimum Load Planning Models shall be analyzed using a Standard Forecast and existing scenario forecast.

Peak and Minimum Load Planning Model should be developed, at the minimum, using the data sources below as input:

Forecast Component	Load Driven Forecast Model	Generation Driven Forecast Model
Baseline	Peak Gross Load Model + Installed DG at 10% of clear sky profile	Minimum Gross Load Model + Installed DG at 100% of clear sky profile
Trend ε_{Trend}	Baseline	Baseline
DER Adoption $P_{DG_{Adoption}}$	In Queue	In Queue
DER Output $\varepsilon_{DG_{Output}}(t)$	10%	100%
Energy Efficiency EE	In Queue (not included in base forecast)	In Queue (not included in base forecast)
New Business Growth Development P_{Step}	In Queue	In Queue
Capacity Reserves $P_{Reserve}(t)$	As Reported	As Reported

Table 10 - Standard Forecast Components

Substations with minimal load and or DG growth and sufficient long-term capacity (both forward, reverse, and contingency) can be modeled without the DG Adoption and DG Output Forecast Components noted in table above.

Substations with medium/high load growth that are not expected to be overloaded in the next 10 years shall include, in addition to the Forecast Component in the above table:

- New Business Growth Queue Forecast Component for years 5 to 10 that is based on recent historical new business growth
- DER Adoption and DER Output Forecast Components

This should result in a more representative new business trend after year 5.

Stations with medium/high load growth (based on Trend and in queue forecast components) that are expected to be overloaded in the next 10 years shall be scaled in load for the following 10 years using the Peak Load Planning Case and a Scenario Based Planning load allocation approach which includes:

- Business-as-usual process for developing the 10-year forecast and peak demand. This is based directly on the prevailing DG interconnection queue and load growth queue that has existing work order factoring in average attrition rates. This will provide an adequate planning goal for years 1-3 since the new business load and DER are well defined, but not as well defined after year 4.
- Accounting for region specific economy, policy, and technology changes. This scenario reflects what local and/or state policies will consider ambitious but achievable goals. Additionally, DER adoption and new business loads are forecasted based on previous historical growth over 10 years at a local level. In general, this Scenario provides adequate planning goals for years 4-10.

4.5.3. Winter Planning Models

Developed to represent the Winter peak and minimum load day conditions for the specific station or group of stations that make up the model. It is also developed from the Base Case, but it includes the 10-Year Winter Load Forecast and Planned Reinforcements already included in the 5-year capital plan.

Stations with significant Winter load growth that can equal or exceed summer Peak Load, resulting from zero carbon emission policies and/or consumer behavior, should be studied using a winter high load case to reflect capacity concerns in areas with expected gas/oil to electric conversion.

The Winter Planning Model process is the same as the Peak and Minimum Load Planning Model process with the only difference being that a Winter 10-year Load Forecast is required for both the Probabilistic and Standard Forecast.

4.5.4. Modeling Yearly Increase

For all cases the first step is to determine all the Possible Planning Models that are to be considered for the 10-year forecast horizon.

NOTE: This results in a maximum of 2 <u>or</u> 4 Probabilistic or Standard Forecasts, depending on whether the shoulder periods are studied as one, or two separate scenarios.

Any station that has a violation for the 10-year forecast is subject to further study. Hereby the objective is to determine the first year by which a need arises:

- For substations with sufficient 10-year capacity that are <u>not</u> expected to be overloaded in the next 10 years (both forward and reverse) the study can be focused on year 10 to determine if there are violation and study the prior years as necessary.
- Stations with medium/high load growth that are expected to be overloaded in the next 10 years shall be scaled in load by year (using the process in Section 4.5 above) in the Synergi model

Identified violations shall be in accordance to the steps in Section 4.6

4.6. Study Methodology

4.6.1. Periodic Assessments

The Eversource Distribution System Planning Group performs periodic assessments/studies of Bulk Distribution Substation facilities to ensure continued compliance with the performance criteria outlined in this document. Studies may also be performed for any of the reasons given below:

- Studies required by State Regulators, such as;
    - The Annual Reliability Report to the Massachusetts Department of Public Utilities (DPU).
    - The Massachusetts Annual Loss Study
    - Other state regulatory mandates
- Eversource initiated studies to investigate deficiencies in the performance of the electric supply system and to identify potential plans for system reinforcements or mitigating measures
- System Planning initiated studies to investigate pre-existing power quality events, resulting from DER penetration, affecting the distribution substation. These include: Transient Overvoltage, 3VO Assessment, DER Impact on Voltage Regulating Equipment, Rapid Voltage Change and Voltage Flicker.

4.6.2. Annual Studies

System Planning Engineers should perform annual assessments of all distribution substations. These assessments are intended to ensure that distribution substations meet or exceed Eversource's Distribution Substation Planning Criteria, refer to Section 2.

Appropriate Base Case Model:

Distribution System Planning will assess **capacity**, **power quality (voltage)**, and **reliability** performance using the appropriate model.

- The Summer/Shoulder Peak Load model together with the 10-year forecast is used to determine potential Substation capacity, reliability, and/or power quality needs during peak load conditions.

- The Minimum Load model together with the 10-year forecast is used to determine potential Substation capacity (mostly due to DER-driven reverse flow), reliability, and/or power quality needs during minimum load conditions.
- If a second system peak is observed during winter months that equals or exceeds the Summer Peak Load, a Winter Peak model together with the 10-year Winter Peak forecast is used to determine potential capacity, reliability, and/or power quality needs.

Substation Normal and Contingency Conditions:
Distribution System Planning will use the Appropriate model to identify violations affecting Distribution Bulk Substations and backbone feeder sections involved in the calculation of the Substation LCC:

- To identify violations under Normal (N-0) system conditions the Planning Base Case models will be used to verify that all substation transformers and backbone feeder sections operate under normal thermal ratings, voltage limits, and acceptable load phase balance, as per Section 2.2 below.
- To identify violations under Contingency (N-1) conditions the Planning Base Case models will be used, together with the guidance provided in Section 4.6 below to verify that all substation transformers and backbone feeders sections operate under the appropriate Thermal Loading criteria specified in Section 2.2 below.

Substation LCC Capability:
Distribution load transfer schemes used in the calculation of the LCC, will be modeled and verified by Distribution System Planning for Bulk Distribution Substations that fall within the following criteria:

- Above 75% of nameplate under normal (N-0) conditions within the next 5 years
- Above 90% of LCC under emergency (N-1) conditions within the next 5 years

Contingency Conditions (N-1) Operational Assessment:

The following criteria apply to all situations where bulk distribution transformers are relied upon for N-1 contingencies to restore electric service to customers, and should be considered during studies:

To determine whether Bulk Distribution Transformers provide an adequate secondary source for the bulk distribution bus loads, the substation bus restoration scheme operation shall be modeled and the following performance criteria under the projected operating loads shall be demonstrated:

- The Bulk Distribution Transformer(s) that provides the alternate supply shall be within the LTE loading criteria for the first load cycle following the ABR scheme operation.
- Additional distribution switching (remotely controlled) shall be available to lower transformer winding loads to the normal rating or below. This additional switching will be implemented when problems will require multiple load cycles to be resolved.
- Distribution bus voltages should be able to be maintained within normal scheduled limits (as per Section 2.4) using transformer load tap changers and/or distribution capacitor banks (substation distribution capacitors banks should be in service under these circumstances to supply increased reactive losses resulting from the loss of a transformer).
- Bulk Distribution Transformer winding loading should be below the Long- Term Emergency Rating and shall not exceed the Short-Term Emergency/Drastic Action Limit Rating.

The following criteria apply to all situations where distribution feeders and remote bulk transformers are relied upon for N-1 contingencies to restore electric service to customers:

To determine that distribution feeders provide an adequate secondary source for the bulk distribution bus loads, the distribution feeders shall be modeled and the following performance criteria under the projected operating loads shall be demonstrated:

- Bulk Distribution Transformer(s) that provide the alternate supply, shall be within LTE loading criteria for the first load cycle following loss of the primary supply. Additional distribution switching (remotely controlled) shall be available to lower transformer winding loads to the normal rating or below. This additional switching will be implemented when problems will require multiple load cycles to be resolved.

- Distribution feeders providing the alternate supply to bulk distribution supply buses, shall not exceed their ratings as per Section 3.1
- To provide acceptable voltage levels at customer service points, distribution feeder primary voltage levels must also be at acceptable levels as per Section 2.4

4.6.3. Contingency Analysis

The following guidance should be used to analyze N-1 Contingency Condition thermal limitations in Bulk Distribution Substations. This guidance is in line with the calculation of Substation Firm Capacity rating.

For Distribution Station in which LCC is equal to Firm:
For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions:

- An N-1 contingency can be modeled at the distribution station by taking the largest transformer out of service and closing the appropriate bus breaker to transfer the load to the remaining transformers.

For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions:

- The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station.

For Distribution Station in which LCC is not equal to Firm:
For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions:

- A distribution model containing the station to be studied in addition to the stations providing Distribution Transfer Switching (DTS) and backbone feeders Capacity shall use for contingency analysis
- N-1 contingency can be modeled at the distribution station by taking the largest transformer out of service and closing the appropriate bus breaker to transfer the load to the remaining transformers.
- The analysis should include transferring load to the station providing DTS capacity

For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions:

- The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station
- The analysis should include transferring load to the station providing DTS capacity

4.6.4. Allowed System Adjustments to Mitigate Capacity and Power Quality Violations:

This section describes mitigation measure that are used in the models to address system violations during Annual and Periodic Assessments of the Distribution System.

The following violations are accounted for during the Annual Studies:
- Thermal violations
- Phase load imbalance
- Voltage violation at the substation bus and feeder backbone as per Section 2.4

System adjustments to mitigate violations include:
- Thermal violations:
  - Reduce load by load transfers or non-wires solution (as per Section 4.8).
  - Increase system capacity by upgrading existing equipment or installing new equipment.
- Phase load imbalance: reduce phase loading by distribution circuit reconfiguration
- Substation Secondary bus load thermal violations: reduce load by load transfer, or increase equipment

capacity

- Voltage Violation:
  - Reduce load by load transfers or non-wires solutions
  - Applying capacitor or voltage regulation.
  - Upgrading or installing new equipment

System Periodic Assessment Review:
As the power system evolves, with increasing DER penetration and electronic loads, the need to study power quality violations more accurately become critical. Electromagnetic Transients (EMT) simulation tools such as PSCAD should be used to analyze transient voltage violations due to switching and load rejection overvoltage events that exceed the limits in Section 2.5 below.

4.7. Documentation of System Constraints

Study Reports:
A report summarizing the results of the Annual Study should be produced by the responsible System Planning Engineer. The report should consider:

- The substation current configuration/capacity along with transformer ratings
- The historical peak and actual loads, actual/planned load transfers and most recent 10-year load forecast
- Assessment of DG connected to each transformer's feeders and any load adjustments made because of these facilities
- System Review Summary, including:
  - Identification of Non-Standard Bulk Distribution Substations and associated violations
  - Non-Bulk Distribution Substation configuration/capacity and potential violations
  - System reinforcements or mitigating measures to plan or investigate further

Based on the violation type (Capacity, Power Quality, and Reliability) the System Planning report should include:

- Substation name
- Substation Summary
- Description of Problem (if applicable)
- Description of Violation (if applicable)
- Substation Equipment Rating and Limit
- Actual Peak Load (Observed year)
- System Review Summary
- Possible Mitigation Actions

4.8. Solution Development

When the system capability does not meet forecasted loads, Planning Engineers must resolve projected violations prior to the violation year as per Section 4.8. Once a list of violations is compiled, Distribution System Planning engineers will identify potential solutions to address those violations affecting:

- Bulk Distribution Substations
- Non-Bulk Distribution Substation
- Feeder Backbone Sections required for substation LCC capacity.

The solution development method adopted by Distribution System Planning is a complex and iterative process which addresses the system needs in conjunction with the capital budget. This approach balances the safe and reliable service provided by the utility with the need to control cost for our customers.

4.8.1. Distribution Bulk Substation Solution Development

Projected violations that are not within the planning design criteria for substation and distribution assets are not tolerated. The planning design criteria (see Section 2) are intended to maintain safe, reliable operation of the power system. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year.

An identified violation can be resolved in different ways. To develop the most viable and cost-effective solutions, Distribution Planning, in conjunction with other engineering disciplines and internal groups, will evaluate several alternatives for cost-effectiveness and technical feasibility.

The most viable and cost-effective solution is presented in the System Planning proposal along with alternative solutions considered. Solutions to resolve potential system violations could include a combination of reinforcement, load reduction, and/or system reconfiguration recommendations. Reinforcement or reconfiguration options that increase capacity include:

- Add transformer cooling
- Replace limiting substation equipment
- Add Reactive Power sources
- Add new transformer or expand substation
- Add new substation

Load Reduction options include:

- Permanent Load Transfer
- Increase load transfer capability (LCC)
- Implement Non-Wires Solutions

4.8.2. Distribution Feeder and Non-Bulk Substation Solution Development

The planning design criteria (see Section 2) are intended to maintain safe, reliable operation of the power system. Projected violations that are not within the planning design criteria are not tolerated. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year. This requires violations to be identified, solutions compared, and projects implemented in an appropriate timeframe (refer to Section 4.9). Overloads can be driven by either new business load growth, load transfer under contingency condition, and baseline growth.

Distribution System Planning should review backbone feeder sections that provide LCC capability and Non-Bulk Distribution Substation Transformers. The traditional solutions that are typically used to address load relief at the distribution level include:

- Upgrade limiting conductor sections
- Add new feeder
- Reduce feeder Load by:
    - Load transfer
    - Implementation of Non-Wires Solutions

Non-Bulk Distribution Substations:

- Add transformer cooling
- Replace limiting substation equipment
- Transfer load
- Add reactive power sources
- Substation elimination/voltage conversion
- Add new transformer or expand substation

4.8.3. Application of Non-Wires Solutions

When evaluating distribution system improvements, Engineers should consider the use of Non-Wires Solutions

(NWS)[6] as an option to defer or avoid distribution system investments. Non-wires solutions are defined as grid investments or programs that use non-traditional solutions to achieve one or more of the following:

- Defer or eliminate the need for distribution grid capacity standard equipment or material upgrade (e.g., distribution lines, transformers)
- Increase distribution grid reliability and/or resilience
- Increase operational efficiency and optimization of the distribution grid (e.g., volt-var optimization)

The primary objective for considering NWS options is to identify solutions with the potential to mitigate system violations (capacity, reliability and resilience) or that enable grid-operating efficiency at a lower total cost to the rate payer, as compared to traditional grid solutions. The Eversource NWS Screening Toolset (ENST) provides a standardized basis for a go-no-go decision for an NWS. When considering NWS alternatives, attention is given to asset health condition and age. The benefit of deferring T&D equipment, with known asset health conditions and/or that are near end-of-life, by using NWS methods should be weighed against the expected remaining useful equipment life.

The NWS options include a broad set of technologies as well as approaches to their integration to increase the range of suitable opportunities. Adopting a broader definition of NWS increases the range of suitable opportunities and enables adoption of emerging technologies, maximizing potential benefits. Some NWS technology examples may be deployed individually or concurrently and may be either in front of or behind the meter; these include, but are not limited to, the following:

- Utility controlled Energy Storage Systems (BESS)
- Solar Installations (Utility or 3rd Party Owned)
- Energy efficiency (EE)
- Demand response (DR)
- Conservation Voltage Reduction (CVR)
- Fuel Cells or CHP (Utility or 3rd Party Owned)
- Conventional Generators (Utility Controlled)

NWS technologies can be combined and integrated with the distribution grid and integrated:

- **Automatic—**Some technologies may provide NWS functions simply through their inherent characteristics. These could include energy efficiency end uses or non-dispatchable DER.
- **Autonomous—**Some technologies (e.g., intelligent end-use devices) may respond to local conditions or follow schemes that are based on programmed set points that can be adjusted according to grid needs. These could include Demand Response, BESS and/or DERs.
- **Dispatch**—Some technologies enable an operator to dynamically specify or direct quantities of supply or demand reduction from specific resources. This could include Demand Response, Battery Storage, DERs and virtual power plants.

Development of NWS Suitability Criteria

Distribution System Planning will develop a list of planned capital projects that may be candidates for avoidance and/or deferral through deployment of non-wires solutions (NWS) ("NWS Candidates"). Each of the capital projects on said list will be evaluated using the ENTS.

The ENTS builds its screening process on the following screening criteria. Until the ENTS is fully operations (Expected End of Q1-2021), planners are to evaluate NWS using the same criteria. NWS suitability can be guided by criteria related to the type of project, the timeline of the need, and the size of the solution (in MW and/or dollar cost). General considerations are provided below. State-specific regulations, settlements, and/or other guidance will be used to develop more specific screening criteria.

Existing Asset Considerations: If assets are part of the proposed capital projects that through their age or asset health index pose a reliability risk, a traditional system upgrade is to be prioritized.

System Obsolescence: For aging and/or obsolete systems traditional system upgrades should be prioritized.

[6] Sometimes refer to as Non-Wires Alternatives or Non-Transmission Alternatives

Project Type Suitability: Looking at categories of traditional projects that might share similar attributes can help identify projects most suitable for NWS solicitation.

Timing Criteria: NWS should only be considered where they can be deployed in time to address a need. Recognizing that it takes time to procure NWS, a timing screen can be used to exclude consideration of particular types of NWS for grid needs that are expected to develop within a certain time frame.

Project Cost Criteria: The proposed capital project is to be compared from a cost perspective to identify which NWS would pose the least cost solution to the rate payer, and if that solution provides a lower cost to the rate payer than the traditional capital project. Hereby capital cost, maintenance, energy, or replacement cost over the planning horizon are considered. The standard planning time frame of 10 years is applied. For NWS that can provide additional revenue streams or value adds, those are to be considered in the Total Cost of Ownership of the NWS to the benefit of the ratepayer. This screening category uses cost thresholds to exclude certain types of NWS from consideration for minor, inexpensive projects in which high transaction costs could disproportionately disadvantage them.

Project Size Criteria: Initial procurements can screen for non-wires solution opportunities that are below a certain size threshold to limit potential reliability impacts from NWS non-performance or outage. Size thresholds would be established upon review of the system planning assessment and the range of associated load at risk, as well as the number of contingent events driving system constraints. Project size thresholds can be used as a guide to ensure that any non-wires solution project failure would be manageable from a reliability perspective.

NWS Technology Screening

Historically, the Least Cost Technically Acceptable (LCTA) transmission and distribution solution, has typically been considered as the only accepted options for replacement/addition of equipment. Given the new opportunities provided by non-wires solutions, an LCTA must be defined as the best option between traditional solutions, NWS or a hybrid (combination) of both. The following suitability criteria establishes guidelines for consideration of NWS:

- Estimate the cost of preferred traditional LCTA solution
- Assess asset condition and life expectancy of the equipment being addressed/studied and compare with the life time duration of the solutions being considered.
- Contact Strategy & Business Development (CSBD) about existing company-owned PV program opportunities in the area.
- Obtain a feasibility assessment from the respective Energy Efficiency (EE) Department about Demand Response (DR), EE programs and Behind the meter Storage. The EE Department will obtain information for outside customers on non-utility programs only. A timeframe of 1-2 months is required by the EE department to obtain an estimated MW saving.
- Concurrent with the review completed by the CSBD and EE Departments, analyze company-owned BESS feasibility. Obtain the respective load curve profile of the substation that needs load relief, including the profile of individual feeders. Establish the following, to address capacity and or power quality deficiencies:
    - The capacity need (MW)
    - Duration of the capacity need (hours)
    - Calculation of the Energy MWh = (MW) x (hours)
    - Yearly frequency of the events
    - Calculation of the battery cost (gross estimate value)

A preliminary BESS gross estimate can be calculated by using the latest version of the National Renewable Energy Laboratory (NREL) U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Cost Benchmark. Refer to most recent table of US Utility-Scale Lithium-ion Standalone Storage Cost for Durations of 0.5-4 hours.

To the selected $/kWh value, the feeder position installation cost (if applicable), must be added. To this total cost the Eversource Indirect Costs and the Allowance for Funds During Construction AFUDC must also be applied. Contact the respective Cost Estimating Department to get these costs.

- Determine the availability of utility-owned and/or controlled DER that is connected to the system with the identified deficiencies.

- Table 1 below can be used as a preliminary review for determining the applicable NWS solution to be implemented standalone or as a combination:

NWS Type	Minimum Years for Solution review prior to implementation	Solution Size Considerations	Duration of Solution	Yearly Incentive Cost
PV-Utility	1-2	Note 1		
BESS-Utility	2-5	Note 2, 3	< 4hr	N/A
DR-WIFI controlled	1-2	0.5-1kW – Residential 200kW – C&I	3hr / 10 times per year	$200/kW-Residential $50/KW-Commercial Note 4
BTM-Storage (existing installation)	1-2	7kW – Residential 100 – 1000kW – Commercial	3hr / 60 times per year	$300/kW-Residential $250/KW-Commercial Note 4
Energy Efficiency	1-2	3-10% of target Substation/feeder load	Permanent	N/A

Note 1 – When applied to an ES feeder, the line section aggregated DER must be less than or equal to 33 percent of minimum load, regardless of DER type mix to minimize the risk of islanding.

Note 2- For grid forming BESS applications short circuit ratio (short circuit of electric system at point of interconnection divided by size of BESS) should be greater than a ratio of 1 at the minimum, optimal design is greater than 2. For grid following BESS applications short circuit ratio should be greater than 2, optimal design is greater than 3. BESS size solutions for Eversource areas with Low/Medium DER saturation and/or low peak shaving: 2.5MW/10MWh and 3.5MW/14MWh.If the solution does not pass the short circuit ratio screen, a detailed study is required an informed go-no-go.

Note 3 - When the BESS is applied inside or in the substation vicinity, consideration should be given to future substations expansions. The BESS should not restrict expected long-term substation upgrades.

Note 4 – Numbers are subject to change

After tabulating all potential NWS that could address the identified system deficiencies, based on Table 1, the preferred traditional LCTA solution should be compared with the implementation of one or a combination of the NWS. The most cost-effective solution should be proposed as the preferred solution and additional least cost-effective solutions should be included as alternatives for the initial funding request (IFR) and through the Solution Design Committee (SDC) process.

4.9. Planned and Proposed Upgrades

During the annual development of the transmission and distribution capacity and power quality plans, System Planning shall design long term solutions (Traditional and NWS) that will address capacity and resiliency needs of all distribution substations. Planned projects, identified in the Low Load and Medium Load Planning Scenarios, that address immediate substation capacity and resiliency needs shall designed and prioritized to be included in the 5-year capital plan as approved projects. Proposed projects, identified in the Long-Term Planning Scenario, that address long term capacity and resilience needs shall be developed but not submitted for approval.

The table below provides a high-level breakdown of the ideal project planning schedule:

Constraint Type	Timeframe	Status	Planning Scenario
Planned	1-5 years	Full development & approval	Low and Medium Load Growth
Planned	5 -10 years	Partially developed	Medium and High Load Growth

Constraint Type	Timeframe	Status	Planning Scenario
Proposed	10 years and above	Conceptual Design	Medium and High Load Growth

Table 11- Ideal Planning Scenarios

Projects that are required within the next 6 years of the Observed Year should be fully developed and approved using the latest version of the Capital Project Approval Process, refer to Section 7.1. A Distribution System Planning Substation Review form should be completed by the responsible System Planning Engineer.

The Form should consider:

- The substation current configuration/capacity along with transformer ratings
- The historical peak and actual loads, actual/planned load transfers and most recent 10-year load forecast
- Assessment of DG connected to each transformer's feeders and any load adjustments made because of these facilities
- System Review Summary, including:
    - Identification of Non-Standard Bulk Distribution Substations and associated violations
    - Non-Bulk Distribution Substation configuration/capacity and potential violations
    - System reinforcements or mitigating measures to plan or investigate further

Based on the violation type (Capacity, Power Quality, and Reliability) the Final form should include:

- Substation name
- Substation Summary
- Substation Equipment Rating and Limit
- Actual Peak Load (Observed year)
- 5 Year Projected Forecast
- System Review Summary
- Possible Mitigation Actions
- In-Service due date
- System Planning Timeline for IFR, SSF, and PAF

Refer to Section 7.3 for a sample template and Section 7.2 for the Capital Project Approval Process.

5. References

The following referenced documents are indispensable for the application of this document:

- ANSI C84.1, Electric Power Systems and Equipment—Voltage Ratings (60 Hz).
- NERC Standard FAC-008-3 – Facility Ratings Methodology
- System Planning Procedure No. 8 (SYSPLAN-008) Calculation and Documentation of Bulk
- IEEE 1547 – 2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces
- IEEE Standard C57.91-2011, "IEEE guide for Loading Mineral-Oil-Immersed Transformers and Step Voltage Regulators"

Distribution Transformer Ratings
SYS PLAN 006 – Determining Transmission System Facility Ratings (EMA)
SYS PLAN 007 - Auto Transformer Ratings Calculation Procedure and Documentation (EMA)

Eversource Information and Technical Requirements for the Interconnection of Distribution Energy Resources (DER) – Jan 21st 2020

IEEE Standard C57.12.00-2015 "IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"

EPRI PTLOAD Version 6.2 Software Manual

DSEM - Distribution System Engineering Manual – T & D Engineering Standard Bookshelf Procedure:

- DSEM 03.30 - Reliability Project Cost Effectiveness is used to evaluate project alternatives.
- DSEM 02.11. – Reliability Indices
- DSEM 02.30 - Automatic Sectionalizing Device Guideline
- DSEM 06.51 - Circuit Zones
- DSEM 10.42 Smart Switches.

Distribution System Planning and Design Criteria Guidelines (ED-3002)

Eversource System Operating Procedure ESOP-28- Single Contingency Load Loss

6. Definitions and acronyms

6.1. Definitions

bulk power system (BPS): Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

distributed energy resource (DER): A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

DER include any non-BES resource (e.g. generating unit, multiple generating units at a single location, energy storage facility, micro-grid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including the following[7]: •

- Distribution Generation (DG): Any non-BES generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity. •
- Behind The Meter Generation (BTMG): A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind the meter. This definition does not include BTMG resources that are directly interconnected to BES transmission. •
- Energy Storage Facility (ES): An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations. •
- DER aggregation (DERA): A virtual resource formed by aggregating multiple DG, BTMG, or ES devices at different points of interconnection on the distribution system. The BES may model a DERA as a single resource at its "virtual" point of interconnection at a particular T-D interface even though individual DER comprising the DERA may be located at multiple T-D interfaces. •
- Micro-grid (MG): An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park. •
- Cogeneration: Production of electricity from steam, heat, or other forms of energy produced as a byproduct of another process
- Emergency, Stand-by, or Back-Up generation (BUG): A generating unit, regardless of size, that serves in times of emergency at locations and by providing the customer or distribution system needs. This definition only applies to resources on the utility side of the customer retail meter.

electric power system (EPS): Facilities that deliver electric power to a load.

flicker: The subjective impression of fluctuating luminance caused by voltage fluctuations. NOTE—Above a certain threshold, flicker becomes annoying. The annoyance grows very rapidly with the amplitude of the fluctuation. At certain repetition rates even very small amplitudes can be annoying (refer to IEEE Std 1453).

inverter: A machine, device, or system that changes direct-current power to alternating-current power.

load: Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

nameplate ratings: Nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER or transformer is capable of sustained operation. NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

[7] NERC – Distributed Energy Resources – February 2017

Summer Peak Gross Load Day: Peak Net Load Day plus generation output (front of the meter) and estimated generation (behind the meter)

New Business Growth: Also called Step Loads in MA or Spot Loads in NH, refers to the new large customer load additions. It includes load additions greater than 500kW and it could be one large customer or a group of customers in a similar area (e.g. large residential developments)

Bulk Distribution Supply Bus: A bus, within a substation that supplies multiple distribution feeder breakers. Nominal voltage shall be below the 69kV level.

Contingency: An event, usually involving the loss of one or more Elements, which interrupts the flow of power on the power system.

Standard Bulk Distribution Substation: Preferred configuration Based on a Double Bus Switchgear or Ring Bus design configuration, refer to Section 2.8.

Single Contingency (N-1): For Standard Bulk Distribution Substation is defined as loss of one bus section, one bus tie breaker, or one Transformer per Event. For Non-Standard Bulk Distribution Substation is based on the Contingency that result in the loss of the largest MVA supply per Event. Distribution System N-1 contingency is defined as the loss of one distribution feeder from a common bus, per event.

Event: Defined as a Single Contingency (N-1) condition lasting one cycle (24 hours)

Distribution Transfer Switching: Load that can be moved from one distribution feeder to another using remotely controlled switches (manual switching operations are not acceptable) within the distribution system. This switching transfers the load from its original bulk transformer supply to a different bulk transformer supply

Element: Any electric device with terminals that may be connected to other electric devices. (e.g.; a transformer, circuit, circuit breaker, getaway cable)

Emergency: Any abnormal system condition that requires automatic or manual action to prevent or limit the loss of substations, or distribution that could adversely affect the electric system.

Observed Year: Or Base Year, is the year for when the Maximum and Minimum Loads are measured/calculated at the substation in preparation for the next 10 years.

Firm Capacity (of a substation):

- Single Transformer Substations: The Firm Capacity of a substation equipped with a single transformer is equal to zero.
- Double Transformer Substations: The Firm Capacity of a substation equipped with two transformers is equal to the smallest LTE (Long Term Emergency) rating of the transformers.
- Three (or more) Transformer Substations: The Firm Capacity of a substation equipped with three (or more) transformers is equal to the total substation supply capability (typically limited by transformer LTE ratings) after loss of a single element, assuming proper operation of automatic transfer/restoral schemes.

Long Term Emergency (LTE) Rating: The rating based on the operational limit of an Element under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the Element, the maintenance history and the calculated capacity that is available in the Element based on the life expectancy of the Element.

Load Carrying Capacity (LCC): The capacity of a Substation is equal to the Firm Capacity plus available Distribution Transfer Switching capacity to adjacent Substations, limited by the Short-Term Emergency Rating of the transformer being relieved by the Distribution Transfer Switching and the transfer capability limit of the affected distribution system elements.

Normal Rating: The rating that specifies the level of electrical loading, usually expressed in mega-volt amperes

(MVA) or other appropriate units that a system, facility, or Element can support or withstand under continuous loading conditions.

Short Circuit Interrupting Rating: The rating of system protection equipment designed to interrupt service under short circuit conditions. The rating is expressed as the amount of short circuit power or current the device can safely interrupt under fault conditions.

Short Term Emergency (STE) Rating: The rating based on the operational limit of an Element under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the Element, and the calculated capacity that is available in the Element based on the life expectancy of the Element.

Distribution System Supply (DSS) Elements: Distribution System Supply (DSS) elements are distribution lines or cables that have similar characteristics and function to transmission supply lines since they feed bulk area load but are designed and operated at lower voltages. DSS elements can supply bulk distribution area loads either through downstream Eversource distribution facilities or directly to customer stations. These reside predominantly in the Eastern Massachusetts portion of the Eversource System. For the purposes of this procedure, DSS elements shall be treated the same as bulk distribution transformers where the system is assessed for the loss of a single DSS element.

3V0: - 59N scheme fed by Potential Transformers on the high (utility) side of the GSU required to sense over voltages on the un-faulted phases during single phase-to-ground faults upstream the GSU.

6.2. Acronyms

DER	distributed energy resources
EPS	electric power system
BESS	battery energy storage system
PV	photovoltaic
STE	Short-Term Emergency Rating
LTE	Long-Term Emergency Rating
DAL	Drastic Action Limit
GSU	Generator Step-up transformer

7. Annex A (informative)

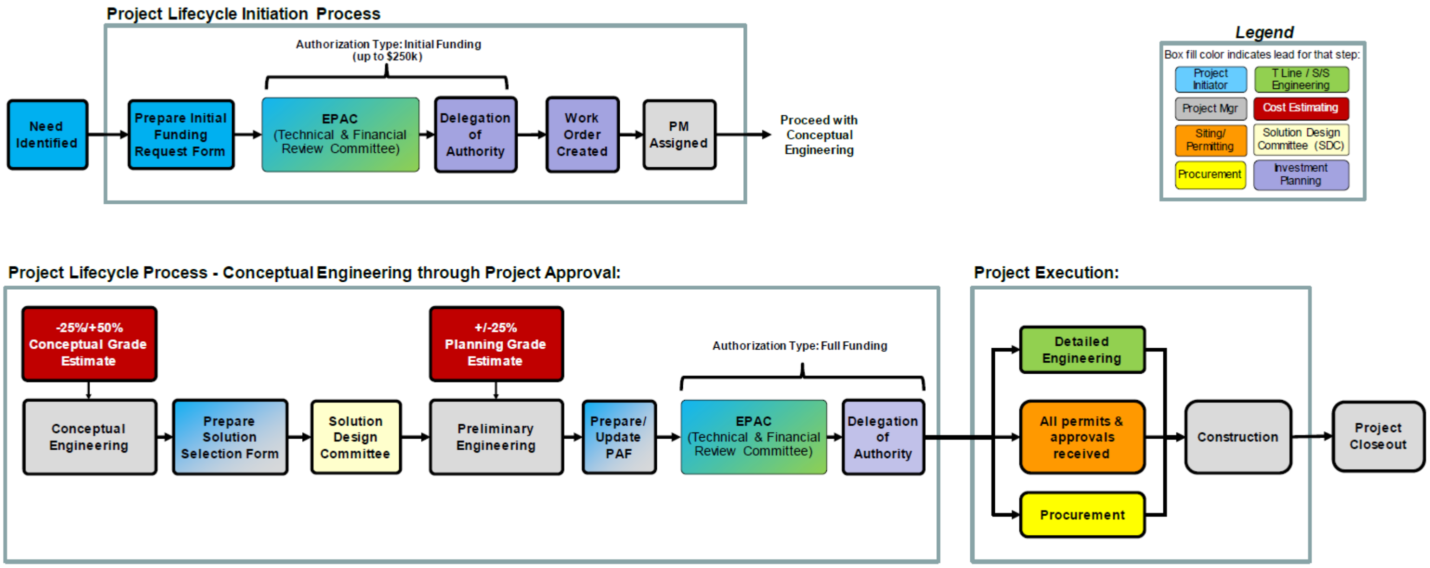
7.1. Reference Documents

SYSPLAN 010 – Bulk Distribution Substation Assessment Procedure	Link to NSTAR Standard
SYSPLAN 008 – Calculation and Documentation of Bulk Distribution Transformer Ratings	Link to NSTAR Standard
DSEM 03.30 – Reliability Project Cost Effectiveness	Link to DSEM Standard
DSEM 02.11 – Reliability Indices	Link to DSEM Standard
DSEM 05.131 – Voltage Limits	Link to DSEM Standard
IEEE 1547 – 2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces	PDF IEEE 1547-2018.pdf
IEEE Standard C57.12.00-2015 "IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"	PDF C57.91-2011 Transformer Loading
Distribution System Planning and Design Criteria Guidelines (ED-3002)	PDF ED-3002 Distribution Plannin
Distribution System Planning Substation Project Template	W Planning Project Template.docx
Capital Project Approval Process Revision 5	PDF JA-AM-2001-A, Rev 5, Capital Project Ap

Table 12 - Reference Documents[8]

[8] In order to determine whether a given document is the current edition and whether it has been amended, visit the standard Bookshelf Site or contact System Planning.

7.2. Attachment D of Capital Project Approval Process



7.3. Distribution System Planning Substation Review Template

Project Type: Capacity, Power Quality, Reliability

Level: Proposed, Planned

Substation Name:

Summary

<u>Substation Ratings:</u>

Transformer	Nameplate	Cyclic Rating (LTE)

<u>Station Capabilities:</u>

Total Station Capacity (N)	Station Firm Capacity (LTE)	Remote Control Transfer	Manual Transfer	Total LCC

<u>2020 Actual Peak Load: MW</u>

2020-2024 Projected load (MW):

2020	2021	2022	2023	2024

Summary of System Review:

Possible Mitigation Actions

Timeline for Long-Term Solution:	
Initial Funding Request (IFR)	*Expected Date*
Solution Selection Form (SSF)	*Expected Date*
Project Authorization Form (PAF)	*Expected Date*