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EVERSOURCE
ENERGY

Distributed Energy Resources
Planning Guide

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INTRODUCTION AND SCOPE

This Distributed Energy Resources Planning Guide (DERPG) has been developed to describe the planning criteria and analyses used to study the impacts of Distributed Energy Resources ("DER") seeking to interconnect to the Eversource Energy ("Company") Electric Power Systems ("EPS"). A consistent and uniform approach to DER Planning will ensure the reliability and safety of the EPS is maintained and the quality of service to all customers meets expectations. The Planning Guide is aligned with applicable safety codes, regulatory requirements, and industry standards and provides uniform planning criteria and standards across the Eversource Service Territory for all aspects of the DER Planning process.

The planning criteria and analyses described herein are used to ensure that DER do not degrade the safety, performance, or reliability of the EPS. This document is a guide, and the Company reserves the right to change its policies, procedures and standards when deemed necessary to maintain the reliability of the EPS and the safety of the Company's customers, workforce, and general public.

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 a formal System Impact Study Agreement (SISA) 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 (including conductor upgrades and substation modifications), metering and supervisory control and data acquisition ("SCADA") requirements, and in some cases operating constraints for the proposed DER.

APPLICABILITY

This guide applies to DER seeking to interconnect to the Eversource system in CT, MA or NH at distribution voltage, i.e., facilities rated at less than 69 kV. Distribution System Impact Studies (D-SIS or SIS) will be performed per these guidelines. Facilities rated at 69 kV and greater are generally considered transmission. Transmission System Impact Studies (T-SIS) are performed in accordance with ISO-NE planning procedures and are out of scope for this document. At the discretion of the Company or in accordance with local tariffs, certain DER (typically those serving residential and small commercial customers) will be screened for system impact without the need for a full System Impact Study. To the extent this document conflicts with local regulations or tariffs, the regulation or tariff shall prevail.

<u>Please note that this document is a guide, and the Company reserves the right to change its policies, procedures and Standards when deemed necessary to maintain the reliability of the EPS and the safety of the Company's customers and workforce, and the general public.</u>

1.0 GENERAL REQUIREMENTS

1.1 Documents and Standards

DER Planning engineers shall be cognizant of the following:

For Massachusetts:

- Eversource distributed generation interconnection tariffs, Standards for Interconnection of Distributed Generation, M.D.P.U. No. 55 for both Eversource Western MA and Eversource Eastern MA (“Interconnection Tariff”).
- MA Technical Standards Review Group & MA Common Technical Standards Manual

For New Hampshire:

- Guidelines for Generator Interconnections
- Interconnection Standards for Inverters up to 100 KVA
- New Hampshire Code of Administrative Rules, Chapter PUC 900
- OP-0045 NH-LCC Minimum Telemetering and Communication Requirements of Merchant Generators

For Connecticut:

- Eversource Energy and The United Illuminating Guidelines for Generator Interconnection, Fast Track and Study Processes.
- Docket No. 03-01-15RE04 (Guidelines for the Interconnection of Residential Single-Phase Certified Inverter-Based Generating Facilities of 25 kW (ac) or Less)

For all States:

- Eversource Distribution System Planning Guide (DSPG)
- The latest approved version of the Eversource DER Information and Technical Requirement document, which is posted on the internet for use by DER customer and developers
- The latest approved version of the IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and IEEE 1547.1 (Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces) adopted by Eversource.
- Latest approved version of UL (Underwriters Laboratories) 1741 (Inverters, Converters, Controllers, and Interconnection System Equipment for use with Distributed Energy Resources.
- The latest approved version of Inverter Source Requirement Document of ISO New England (ISO-NE) adopted by Eversource. ISO-NE Document and Procedures, including:
  - Operating Procedure No. 12 – Voltage and Reactive Control

- Operating Procedure No. 14 – Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources
- Operating Procedure No. 17 – Load Power Factor Correction
- Operating Procedure No. 18 – Metering and Telemetering Criteria
- ISO-NE Planning Procedure 5-1 – Procedure for Review of Governance Participant's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures, and Forms); and
- ISO-NE Planning Procedure 5-3 – Guidelines for Conducting and Evaluating Proposed Plan Application Analyses.

1.2 Interconnection SIS Required Technical Information

Without adequate technical information regarding the proposed DER, the impact study process can be delayed and inefficient. DER Planning engineers should perform a thorough review of the provided documentation before commencing the study and request appropriate updates to customer documentation that are required for study completion. Required information includes but is not limited to:

D-SIS required models and documentation:

- DER equipment information (type, size, make, model, requested export limitations or other equipment deratings or operational restrictions, etc.).
  - For solar Installations of any size, both inverter AC rating and the panel DC rating.
- Proposed location and desired interconnection point.
- PE Stamped One-Line must adequately identify the following elements:
  - GSU rating, winding configuration, Z%, X/R ratio.
  - Grounding method, including the above for all grounding transformer(s), if applicable, or neutral grounding impedance Zn in Ohms if applicable.
  - Proposed Inverter Settings, Equipment Make and Model, UL 1741 SA or later indication per the current requirement.
- Effective Grounding calculations to show X0/X1 ratio.
- Fully functioning and site specific PSCAD models of the DER facility shall be provided for all projects > 1 MW.
  - PSCAD models for projects ≤ 1 MW may be requested during the SIS if required to perform further transient overvoltage (TOV) and risk of islanding (ROI) analyses.
- For inverter-based DER:
  - Unintentional Island Detection Information.
  - Documents that show compliance with TOV requirement.
  - Inverter certification document and specification sheet.
- For Non-inverter-based DER:

    - AC/DC schematics.
    - Documentation of the Independent Review for Existing Generation Sites (applicable only in NH).
- For BESS Systems:
    - Will the battery be charging from the grid?
    - Export/Import limit
    - ISO market participation
    - Ramp rate
    - BESS Questionnaire

2.0 STUDY KICK-OFF AND SCOPING

Prior to initiating the study, DER Planning should arrange an optional internal scoping meeting with the appropriate disciplines, e.g., System Planning (T&D), Distribution Engineering, Protection & Controls, Substation Engineering, and System Operations. The scoping agenda should include:

- Proposed DER equipment and Point-of-Interconnection (POI).
- Review of the SIS identified cases (N-0 and N-1)
- Known circuit and substation limitations.
- Availability and accuracy of Eversource system model (Synergi, Aspen).
- Load allocation, feeder loading, verify regulator and cap bank location and control mode
- Existing DER on the circuit and station (including alternate configurations).
- Planned capital projects that are approved and fully funded and scheduled for completion in the next year that may impact the study. The inclusion of planned capital projects should be documented in the System Impact Study report. Any planned capital projects that are a pre-requisite for full DER operability must be documented in the Interconnection Agreement (IA) with appropriate timelines, terms, and conditions.
- Protection concerns such as direct transfer trip (DTT) and fuse / device coordination
    - Determine what model will be used to evaluate fault currents and effective grounding (Synergi, Aspen).
    - Determine staff performing reviews.
- Cap Bank and Line regulator settings
- Load tap changer (LTC) controls and the potential for reverse power
- Existence of ground fault overvoltage (3V0) protection at the station transformer(s)
- DER operational requirements
- The impact on the transmission system and possible need for a T-SIS or Transmission screens.

   - ISO-NE Planning Procedures dictate when transmission studies or screens are required. Eversource Transmission Interconnections and Transmission System Planning shall be consulted for all DER applications > 1.0 MW.
- For DER Group Studies, Eversource will follow all applicable rules and procedures in Order DPU 17-164

3.0 DER OPERABILITY AND N-1 CRITERIA

Eversource's N-1 planning standard as defined in the Eversource Distribution System Planning Guide (DSPG) requires that bulk distribution substations shall be designed to sustain any single contingency (N-1) event with no loss of customers. This N-1 planning standard applies to all load (reverse and forward) and all customers (load and DER alike). The design standard aims to maintain adequate levels of operational flexibility which ensures power quality and reliability that meet or exceed our customers' expectations.

The application of an N-1 planning standard to DER system impact studies is critical due to the increasing level of DER penetration (number and size) at Eversource's bulk distribution substations. With increased DER penetration comes the associated thermal capacity, voltage, and power quality impacts, which can be observed primarily during reverse power flow conditions (low load/high generation periods) on Eversource's distribution lines and station equipment. Maintaining operational flexibility on LCC lines[1] and substation equipment that are intentionally designed to pick up customer load and generation during outages resulting from N-1 contingences at the station is especially critical to ensuring reliability and service continuity for all customers.

Tripping DER off-line (either remotely via a System Operator, or automatically via a Direct Transfer Trip scheme) during an N-1 event shall not be permitted as it exposes Eversource's DER customers to the risk of outages for extended durations (weeks or months), which is not consistent with state clean energy goals. This extended outage scenario fails to meet Eversource's reliability planning standards and does not qualify as a suitable mitigation for substation N-1 criteria violations. Additionally, tripping particular DER off-line during N-1 events would pose a major operational challenge for the Company. The combination of the N-1 contingency event with the need to identify and trip certain DER would create unnecessary additional operator burden, potentially delay response, and negatively impact reliability for all customers (load and DER alike).

The DER System Impact Study shall include N-1 (contingency) cases that:

[1] Distribution feeders that have been intentionally designed to provide transfer capability between bulk substations during emergency conditions shall be considered Load Carrying Capability (LCC) lines, since they contribute to the LCC of that station.

1. Are triggered by the loss of a bulk substation element (at the DER station or adjacent inter-dependent stations)
2. Require reconfiguring the distribution system, based on pre-determined operational procedures, to restore customer load and generation during the contingency event at the bulk substation, where the distribution system configuration results in:
   a. A different supply source (bulk transformer, feeder, or line section) for the DER under study, or
   b. The same supply source (bulk transformer, feeder, or line section) for the DER under study, but with different load or generation levels (i.e., load and/or generation are transferred onto or from the supply source).

All identified N-1 cases per the criteria above shall be evaluated under the N-1 system configuration and worst-case applicable system loading scenario, and shall go through the same set of analyses as the N-0 (base case) prescribed in the DERPG, where applicable. When N-1 cases result in required upgrades/mitigations (e.g., station upgrades, line reconductoring, 3V0, DTT, etc.) the DER customer shall be responsible for the upgrade costs. The DER customer <u>shall not</u> be offered the option to go off-line during any studied N-1 scenarios as an alternative to funding identified upgrades.

DER shall not be permitted to operate in system configurations that were not included in either the original SIS or via subsequent evaluation.

4.0 EXPRESS FEEDER AND STATION FEEDER BREAKERS

4.1 Express Feeders

Express feeders will be built to all normal construction and power quality standards, including proper voltage at the POI. Operation of the DER on the express feeder should not limit Eversource's ability to serve future customers from that feeder.

Future use of Express feeders to serve Eversource customers will be specifically addressed in each Interconnection Agreement.

Eversource shall use only customary practices to acquire the permits and easements that may be necessary to site an express feeder.

4.2 Right-of-Way (ROW) Issues

System upgrades to accommodate DER, including express feeders, shall not limit or hinder the future use of Eversource ROW. The DER developer should not be given a preliminary indication that space in an existing ROW will be available until management approval has been obtained.

Eversource ROW cannot be used for private distribution infrastructure owned by 3rd parties.

Tapping of a ROW line to bring service to a new DER customer requires review and approval by Distribution Engineering and System Operations. ROW taps can decrease area reliability, slow restoration, and result in poor availability for the DER customer.

Any lateral crossings of a ROW must be designed in accordance with Eversource standards. Ownership, maintenance, and any legal issues associated with the crossing will be included in the Interconnection Agreement or a separate agreement.

All requests to co-locate facilities parallel to, within or adjacent to Eversource transmission and distribution line corridors shall follow Eversource Administrative Procedure M2-SI-2008 (Co-Location Requests with Transmission).

4.3 New or Existing Breaker Positions

Approval in accordance with internal procedures shall be granted by an Eversource review committee prior to approving any substation real estate and/or spare breaker capacity for purposes of DER interconnection. The decision to offer a substation breaker position to a new DER shall consider future expansion plans, space limitations, etc. Substation Engineering and System Planning must approve any conceptual interconnection designs that may limit future system expansion and/or reconfigurations.

The DER developer should not be given a preliminary indication that a breaker position will be available until approval has been obtained.

5.0 VOLTAGE REGULATION BY DER

The DER facility shall not actively regulate the voltage of the EPS unless specifically agreed by the Company. Initial load flow simulations for inverter-based DER should be performed with the DER at fixed unity power factor (PF = 1.0). To mitigate voltage violations, the DER may be modeled with a fixed, off-unity PF (i.e., absorbing VAR) that is at any point ≥ 0.9 as a least-cost mitigation. In areas of high penetration, and at the discretion of the company, alternative voltage control methods such as volt/var may be considered.

Eversource is required to adhere to ISO-NE Operating Procedure OP-17 – Load Power Factor Correction. DER operating at fixed or dynamic (Volt/VAr mode) off-unity power factor that conflict with the objectives of OP-17 shall be reviewed and may require mitigations. Consideration shall be given to Capacitor banks, Dynamic Reactive Devices (DRD) and/or Battery Energy Storage Systems (see DSPG Section 2.11 - Battery Energy Storage Systems Design Criteria).

6.0 REQUIRED ELEMENTS OF THE SYSTEM IMPACT STUDY

6.1 Steady-State Thermal and Voltage Criteria

For all modeled cases, the addition of the DER shall not result in any equipment exceeding its normal rating.

For all modeled cases, the addition of the DER shall not cause the voltage at any point along the EPS to deviate from +5% / -5% of nominal (Note, this voltage is at the customer service point. During SIS, a more stringent limit is used to account for voltage drop across the service transformer and the secondaries) When evaluating Energy Storage Systems (ESS)in the charging mode, primary voltage at the POI must remain above 0.983 p.u. or else mitigation is required.

Prior to performing any project study cases, one or more “pre-project” cases must be conducted to screen for existing thermal and voltage concerns. System issues identified in these pre-project cases must be mitigated in the model prior to evaluating the system impact of the DER.

The results will be presented in tables showing the voltage and loading results. Any voltage or thermal issues will be identified, and possible mitigation options will be provided such as adjustments to the voltage regulation settings, upgrade of feeder conductors, and adding reactive power control capability to the DER with due consideration of the IEEE 1547 Standard. The study report should identify the voltage regulation devices on the circuit, how they are programmed in the field, and how they were captured in the models.

If off-unity PF operation is indicated as a method to mitigate over-voltage concerns, the load flows will be re-evaluated. Increased VAR demands at the substation transformer, caused by the DER operating off-unity, will be determined, documented, and mitigated as required.

6.2 DER Impact on Voltage Regulating Equipment

The SIS will evaluate and document the impact on Eversource voltage regulating equipment (LTCs, Caps, Line Regulators) due to DER ramping between 5% and 100% of nameplate power output. Any concerns with the operation of voltage regulation equipment shall be discussed with Distribution Engineering to evaluate if mitigation is required.

6.3 Rapid Voltage Change and Voltage Flicker

Rapid Voltage Change (RVC)

Simulate an instantaneous trip of the generator from full 100% to 0% output, and vice versa. Any dynamic reactive capabilities of the inverters shall be disabled, and other voltage regulating devices on the circuit should be locked. The rapid voltage change criteria is 3% on distribution voltages per IEEE 1547-2018 clause 7.2.2. Results >2% (either in the initial simulation or after some partial mitigation) should undergo the additional flicker analyses, see below. Only the applicant DER along with existing DER within quarter mile is included in the RVC test cases.

Flicker Assessment

Simulate an instantaneous decrease in the generator from full 100% to 5% output, and vice versa. If the project will be operating at off-unity Power Factor (Fixed or Dynamic), any dynamic reactive capabilities of the inverters shall be enabled in the model. Other non-dynamic voltage regulating devices on the circuit should be locked. The flicker criteria are based upon the type of generation as follows:

- Inverter Based – 2%
- Wind – 3%
- Hydro 3.5%
- Rotating Machine – 3%

As part of the flicker evaluation, simultaneous output changes of other DER sites on the circuit may be considered for the analysis if they are the same type since a common event (such as variable cloud cover) could affect more than one DER site. The default approach is to include solar projects within ¼ mile of the solar project under study.

Ramp Rate control can be considered as a mitigation for flicker. An initial ramp rate of 1MW/min will be considered during the SIS. Any mitigation that reduces the operational flexibility of the DER must be agreeable to the owner and documented in the Interconnection Service Agreement (ISA).

6.4 Transient Overvoltage (TOV) and Transient Analysis

Transient overvoltage is of concern due to potential load rejection overvoltage (LROV) and Ground Fault Overvoltage (GFOV) by inverter-based DER. There is concern that during step changes in load (such as tripping of an upstream device), the proposed inverters may cause transient over voltages in excess of 1.2pu, which can potentially cause damage to the customer's equipment, utility equipment, and/or nearby customer equipment. Due to this concern, Eversource requires that the customer demonstrate that the inverters limit their cumulative overvoltage according to the transient overvoltage curve in IEEE Std. 1547-2018 clause 7.4.2. If the inverters do not demonstrate compliance to the curve given in the standard, additional utility upgrades and/or transient analysis may be required to mitigate the overvoltage concern. The customer may demonstrate compliance by:

- Providing a letter from the inverter manufacturer indicating that the proposed inverter is capable of and set to trip for no higher than 1.4pu voltage in 1ms or less clearing time. *Note: "clearing time" is defined in IEEE 1547. Any implications of solely "trip time" may not sufficiently clear the TOV (e.g., a circuit breaker typically trips in 1-2 cycles, but an inverter may cease to energize by opening IGBTs in milliseconds).*

- Other means proposed by the customer/inverter manufacturer may be acceptable on a case-by-case basis.
- All documentation shall include the applicable firmware version(s). The correct firmware version shall be demonstrated by the customer during witness testing/final review. Generally, all DER installations 500kW and larger shall provide this documentation. The Company reserves the right to ask for this documentation for smaller DER projects undergoing study and/or additional review. DER projects <100kW are exempt from this data requirement.
- In future revisions, UL 1741 test procedures are anticipated to cover this requirement. In the interim, customers large enough to require an impact study or additional review are required to demonstrate compliance to avoid potential damage to customer and utility equipment. Regardless of utility documentation requirements, it is the responsibility of the DER customer to meet all applicable standards, including but not limited to the latest version of IEEE 1547.

A Transient Analysis (using PSCAD or equivalent software) shall be performed as part of the SIS under the following conditions:

- TOV – A dynamic study may be required for TOV when a DG is larger than 499 kW and is identified as increasing the aggregate generation on a feeder / substation bus to >= 115% of gross minimum load.
- Other – A dynamic TOV study may be required for other cases where there are other system concerns, which cannot be properly evaluated inside of Synergi and require time-based analysis.

If the analysis determines that a transient over-voltage condition is caused by the DER, mitigation shall be required. The analysis shall also screen for pre-existing transient over-voltage issues.

6.5 Transformer Power Capability

Substation Transformer Reverse Power Flow

Any proposed DER facility that has the potential to cause reverse power flow through an Eversource substation transformer will require an Impact Study. The Impact Study will specifically address the ability of the transformer to accommodate reverse power flow. The following items will be evaluated:

LTC Design, Controller Type and Controller Settings: The Impact Study will evaluate the capability of the LTC and controller to accommodate reverse power conditions and to respond with appropriate control strategies.

Voltage and current inputs must be available to the LTC controller.

Any LTC controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs. The requirement to add a backup controller will also be evaluated.

For LTC evaluation all substation circuits must be modelled to ensure an LTC response to the reverse power flow from the interconnecting DG does not cause a low voltage condition

Capacity Limit: As an initial screen, unless constrained by other more limiting requirements, aggregate DER (in kVA) will be permitted up to 95% of the transformer's top nameplate ampere rating (in kVA) with maximum cooling operational. This limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer. This assessment must include N-1 scenarios, i.e., loss of the largest transformer at a multi-bank station, or other N-1 configurations in which the DER is sourced from an alternate station or those in which existing or queued DER from an electrically adjacent station is transferred to the applicant DER source station (see Section 3.0 for a discussion of required N-1 scenarios).

If the initial screen is failed, an assessment will be made of the absolute minimum load that may be considered as protection against transformer backfeed in excess of the nameplate. The default minimum load for this review will be 67% of the historical minimum loading on the transformer in the configuration being analyzed. Engineering judgement will be used to consider if a more conservative assumption is required, e.g., most heavily loaded feeder is in a switched configuration.

<u>Substation Transformer Forward Power Flow</u>

Any ESS during SIS is analyzed as a DER as well as a load customer due to the charging capabilities of the battery. Any proposed ESS facility that has the potential to cause loading concerns on a substation transformer will require an Impact Study. The Impact Study will specifically address the ability of the transformer to accommodate the additional loading. The following items will be evaluated:

Capacity Limit: As an initial screen, unless constrained by other more limiting requirements, aggregate ESS in addition to the existing gross peak load will be permitted up to 90% of the transformer's LTE rating. This assessment must include N-1 scenarios, i.e., loss of the largest transformer at a multi-bank station, or other N-1 configurations in which the DER is sourced from an alternate station or those in which existing or queued DER from an electrically adjacent station is transferred to the applicant DER source station (see Section 3.0 for a discussion of required N-1 scenarios).

6.6 3V0 Assessment (Transmission Ground Fault Detection)

This section details a methodology that facilitates the identification of the following:

- Potential for Ground fault Overvoltage (GFOV),
- Condition when such a potential may be present

When it is determined that GFOV protection is required, the tripping time shall be compared with the Temporary Over Voltage characteristics of the transformer high side arresters to identify the need to replace the arresters with higher rated units and evaluate impact on the transformer BIL rating. In addition, the line arresters on the high/transmission side of the substation transformer may need to be evaluated.

This guideline provides requirements and methodology for identifying where 3V0 or other transmission-side ground fault protection may be required for bulk distribution substations. It is also applicable to the evaluation of high-side protection at non-bulk distribution substations. It considers the fact that Distributed Energy Resources (DERs) can energize a substation transformer prior to reverse power flow occurring and requires the protection when standard DER-to-minimum load ratios are exceeded under various operational system conditions. The DER-to-minimum load ratio screens are to be completed for all potential scenarios (i.e., normal and N-1 alternative configurations). The methodology included in this document will identify the need for 3V0 protection based on existing, proposed and forecasted DER penetration over both short- and long-term planning horizons.

Distribution substations are typically designed for one-way flow: to provide power to distribution customers from the transmission or sub-transmission system. The addition of Distributed Energy Resources (DER) can require additional fault protection for ground faults on the high/transmission side of distribution substation transformers. This protection is typically known as 3V0, or 59N, and detects the neutral shift that occurs when the ungrounded high side of the transformer is energized from the low side for a ground fault. Without this protection, the DER at certain penetration levels can continue to energize the substation transformer during high-side ground faults, causing potential damage to equipment and/or present a safety hazard. This policy discusses the screens for where 3V0 or other high/transmission-side ground fault protection may be required for distribution substations. It considers the fact that DERs can energize a substation transformer prior to reverse power flow occurring and requires the protection when DER to minimum load ratios are greater than 67%, considering a single N-1 contingency scenario (feeder or transformer contingency). This will ensure high side ground faults have adequate protection in place when DERs may be capable of energizing the ground fault when the remote (source) substations have tripped.

Concerns for DERs 'back feeding' into a transmission ground fault arise before the aggregate penetration of DER can cause reverse power at a given substation transformer. The concern arises when the aggregate DER can continue to *energize* the substation transformer. Although this is possible with nearly any DER level[2], the loads can help 'swamp out' the generation in some cases, meaning 3V0 may not be required if the DER penetrations are sufficiently low enough. The existing Sandia screens for risk of islanding are the basis of the 67% threshold for determining where 3V0 is required

Applicable Transformer Configurations

This verification is always needed for delta high-side transformers, as well as any transformer configuration containing or acting as an ungrounded wye or delta that would effectively break zero sequence continuity/the ground fault current path between transmission and distribution (e.g., Yg-D-Yg, D-Yg, Y-Y, or Y-Yg). Y-ground-Y-ground transformers[3], provided there is no delta or phantom tertiary in the transformer, should pass through transmission-side voltages and currents the DER will be able to see, and are not applicable for this document. The transformer configuration and protection requirements should be determined in consultation with the Protection department or by reviewing the list of substation evaluations for 3V0 provided by the Protection department.

6.7 Effective Grounding

Where Effective Grounding Is Required

Effective grounding shall be required for all DER interconnections where any of the following is true:

- The fault current at the point of common coupling (PCC) is caused to increase by at least 10 percent of the existing value.
- Areas where fault current may already be deemed excessive.
- DER interconnections equal to or larger than 1MW.
- Anywhere there may exist a potential islanding concern regarding generation to load ratio.

Effective Grounding Methods

To achieve effective grounding, the DER owner shall design and install an interconnection system where the ratio of the DER's reactance parameters meets the following criterion:

$2 < X0/X1 < 3$

[2] Transformer magnetization impedance requires very little current to overcome.

[3] Also assumes high magnetizing impedance for 3-legged core-type transformers.

where

> X0 = zero sequence reactance, and
>
> X1 = positive sequence reactance at the PCC

The DER shall use one of the following methods:

- A generator step-up transformer (GSU) with a reactively grounded neutral on the high (utility) wye-connected side and a delta configuration on the low (generator) side.
    - Reactor sizing calculations confirming conformance to Eversource design requirements shall be submitted by the customer prior to scheduling of the witness test. The DER owner shall also supply specifications and ratings for all equipment as it pertains to all reactor sizing calculations.
    - Note: This method is preferred with respect to ferro-resonance and harmonics concerns for most generators.
- A GSU with a grounded-wye / grounded-wye configuration and a grounding transformer on either side of the GSU (for DER that do not source ground fault current).
- A delta high (utility) side GSU configuration and a grounding transformer on the high (utility) side.

Where Effective Grounding is Not Required

Where DER connections are not required to be effectively grounded, delta windings shall be used on the high (utility) side of the GSU. For this type of interconnection or installations with existing delta connected transformers on the utility side which are serving as a GSU, a customer provided 59N (3V0) scheme fed by PTs on the high (utility) side of the GSU shall also be required to sense over voltages on the un-faulted phases during single phase–to−ground faults upstream of the GSU. The 59N requirement is in addition to normal protection requirements specified for DER installations at Eversource.

6.8 Adverse Impact of Unintentional Islanding

Unintentional Islanding by the DER of all or part of the EPS (meaning a part of the EPS is kept energized by the generating facility after the area has been de-energized) is prohibited as it may result in unsafe conditions on the EPS.

Risk of Islanding (ROI) – unless otherwise mitigated, a dynamic study is required to further assess the ROI when a project fails the applicable screens during an impact study.

6.9 Compliance with ISO-NE Source Requirement Document for Inverters

The SIS will review the DER project information relative to compliance with the SRD and most up to date requirements, e.g., Ride-Through 2.0 and UL 1741 requirements. The study report will document the voltage and frequency settings required for compliance. The required settings and control modes must be documented on the final customer one-line diagram.

6.10 Short Circuit Evaluations

Pre- and Post-project faults currents will be determined and documented. Equipment short circuit ratings included in the system model will be compared to the available fault calculated in ASPEN One Liner or Synergi, including potential contribution from the proposed DER in aggregation with other generation on the distribution circuits. A review of the existing protection scheme and coordination will be included.

The maximum allowable fault duty on the station bus is 10 kA without the use of reactors. The DER interconnection cannot cause the substation bus fault duty to exceed 10 kA or result in exceeding the interrupting rating of distribution line equipment. Failure of this criteria requires review by Protection and Control Engineering.

DER interconnections, in aggregate with other generation on the distribution circuit, should not contribute more than 10 percent to the maximum fault current of the distribution circuit at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling (PCC). Failure of this criteria requires review by Protection and Control Engineering.

6.11 Short Circuit Ratio Evaluations

A short circuit ratio ("SCR") test will be performed at the Project's terminal bus (e.g., 480V or 600V) to determine the electrical strength of the external Eversource system at that location. The system is to be tested under N-2 and N-3 conditions. The N-3 condition is an operational consideration and not a design condition at this time. The minimum SCR requirement provided by the DER inverter manufacturer must be compared to the calculated SCR under all conditions.

The short-circuit MVA will be computed for different line-out conditions to determine the lowest measured SCR at the interconnecting point. The Aspen case used should represent the minimum fault condition where all local generators in the vicinity of the project (including the Project itself) were taken out-of-service during the computation. The N-0 base case should also be performed for the pre-project condition without any loss of transmission elements.

DER Planning must coordinate with ISO-NE (for FERC jurisdictional projects) and/or Transmission System Planning to ensure that this evaluation is captured in either the Distribution SIS or the Transmission SIS.

6.12 Communication and SCADA Requirement

The SIS shall note any relevant requirements based on the latest approved version of the Eversource DER Information and Technical Requirement document. The SIS shall document whether Eversource will require SCADA or other real-time communication to either i) an Eversource-owned device at the POI or ii) a customer-owned device beyond the POI. Below are some of the technologies that help facilitate monitoring and control of DER through SCADA devices:

RTAC-to-RTAC Design

When monitoring and operating customer equipment is required, all configurations and communications shall be done in an RTAC-to-RTAC scheme. This configuration requires two SEL RTAC cabinets:

- **Eversource RTAC** - This device will be installed at the point of interconnection on the Eversource side and will be used to transfer the data from the customer RTAC back to Eversource control centers. This RTAC will have the capability to provide indication, status points and Open/Close controls.
- **Customer RTAC** - This device will be installed and maintained by the customer and will facilitate the reception of the trip signal from the RTAC via Eversource RTAC and a command from DSCADA. It will have a hard-wired contact to trip the customer breaker. At the same time, this device facilitates the collection of the different statuses and alarms from the DG system and transmits the data back to the Eversource DSCADA system.

There are scenarios where the RTAC design could be called for without a POI recloser. Eversource still requires a Utility Accessible Disconnect Switch (UADS) to be installed on site.

Point of Interconnection (POI) Reclosers

All POI recloser installations will be programmed for Eversource circuit protection only. It is not intended to provide protection for customer owned equipment. The intention of a POI Recloser is to isolate the Customer from the Eversource system for the following conditions:

a. Faults between the POI Recloser and the first customer owned fault interrupting device.
b. Power flow into the Eversource system from the customer bus. Power flow could be sourced by a customer owned generator.
c. Faults not adequately cleared by the customer's fault interrupting devices. In the event of customer equipment failing to operate, the POI recloser will act as a failsafe for the Eversource system.

Overcurrent based fault protection settings will be coordinated against the Eversource system regarding customer load. Coordination with customer owned protection will be attempted but cannot be guaranteed. Reverse power and reverse current protection settings will be utilized to detect current flowing from the customer bus into the Eversource system. Time delays settings for these conditions will be set by Protection & Control Engineering.

a. Reverse power will be used to detect load flow from the customer bus.
b. Reverse current will be used to detect current flowing from the customer bus to a fault on the Eversource system.

Interconnection Requirements based on Site Conditions

DERs Less Than 500 kW

Certified and non−certified DER less than 500 kW generally do not require DSCADA visibility for standalone facilities and behind−the−meter facilities. However, on a case−by−case basis, Eversource reserves the right to require DSCADA visibility as required.

DERs Greater Than or Equal to 500 kW and Less Than 1 MW

DER facilities between 500 kW and 1 MW require that DSCADA visibility and control is implemented in the design of interconnection. It will be at the discretion of Eversource engineering to determine the means of DSCADA visibility. Eversource requires a RTAC for DSCADA control. Eversource may require a POI recloser to provide coordinated fault protection, reverse power automatic isolation and a failsafe interrupting device in the event that DSCADA controls fail to isolate all DER sources.

DER Greater Than or Equal to 1 MW

DER facilities greater than or equal to 1 MW require that DSCADA visibility and control is implemented in the design of interconnection. It will be at the discretion of Eversource engineering to determine the means of DSCADA visibility. Eversource requires a RTAC for DSCADA control.

- Standalone Facilities: Common practice for standalone facilities is to require a recloser. POI recloser to provide coordinated fault protection, reverse power automatic isolation and a failsafe interrupting device in the event that DSCADA controls fail to isolate all DER sources.

Behind-The-Meter Facilities: Special consideration should be given to large load customers who have DER facilities equal to or greater than 1 MW. For these applications, a DSCADA RTAC is required and will be configured to disconnect the connected DER facility only. Eversource may require a POI recloser to provide coordinated fault protection, reverse power automatic isolation and a failsafe interrupting device in the event that DSCADA controls fail to isolate all DER sources