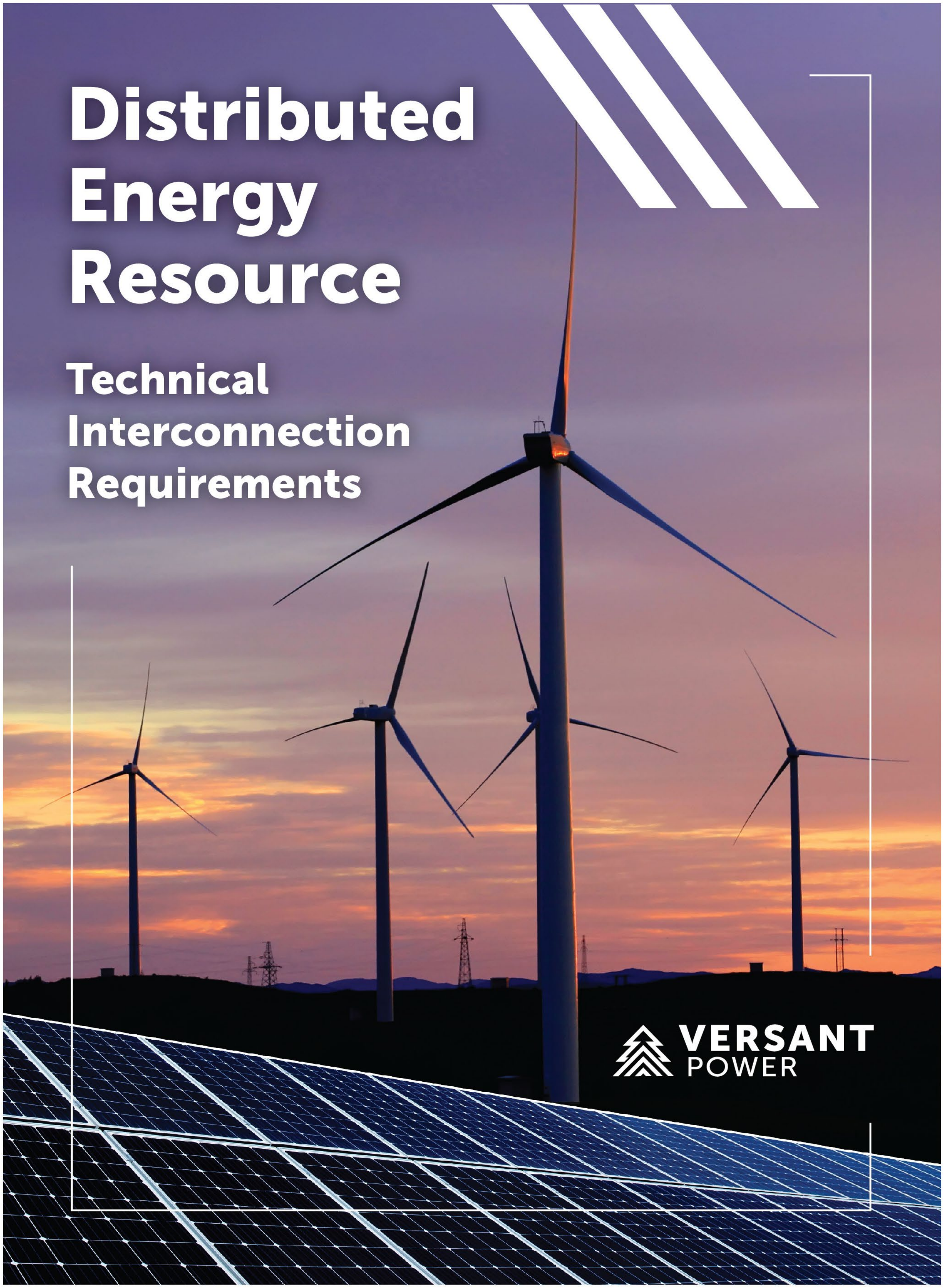
Distributed Energy Resource

Technical Interconnection Requirements



VERSANT POWER

A MESSAGE TO THE DISTRIBUTED ENERGY RESOURCE OWNER

This document is intended for a technical audience. The requirements established throughout this document are intended to provide guidance to the Distributed Energy Resource (DER) Owner for interconnection of a DER Facility to the Versant Power Distribution System. These interconnection requirements include but are not limited to the following:

1. Preliminary planning
2. Project execution
3. Procurement
4. Construction
5. Testing and commissioning
6. Energization
7. Operation and maintenance.

The information and requirements contained in these DER Technical Interconnection Requirements are not a substitute for the Versant Power formal interconnection process. All process documentation and relevant interconnection information can be found at versantpower.com.

For all interconnection inquiries, please contact Versant Power's Distributed Generation Team at: **dginterconnections@versantpower.com**.

The information contained herein is intended to present technical information to help customers determine the requirements for their DER Facility as well as Versant Power's interconnecting equipment and distribution system. This information, which reflects Versant Power distribution standards and industry interconnection standards as we currently understand them, may change for a variety of reasons, including system requirements and operational changes. Versant Power expressly disclaims any and all liability for the content, or any omissions, inaccuracies, errors or misstatements contained herein. This information is provided without warranty of any kind, either expressed or implied, including implied warranties of merchantability and fitness for a particular purpose.

Revision History

Rev.	Date	Revised By	Description
0	MM/DD/YYYY		New Document

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1 Introduction

Versant Power permits operation of customer-owned distributed energy resources in parallel with its Electric Power System (EPS) whenever this can be done without affecting the quality of service to other customers or the safety of the employees and equipment of Versant Power. In order to carry out responsibilities to all customers, the Company must assure that any interconnections to the EPS meet certain protocols. Those requirements and procedures are described in this DER Technical Interconnection Requirements document. Due to the rapid growth of DERs within the Versant Power service area[1], we may need to revise our interconnection requirements and procedures frequently and without notice. In addition, any fees or other costs listed in this document are subject to change by the Maine Public Utilities Commission at any time. We look forward to working with you to facilitate a safe, reliable and successful interconnection.

1.1 Objectives

The Interconnection Requirements were developed in accordance with the following objectives and are required to be followed throughout the lifecycle of a DER Facility:

1. **Safety is of critical importance to Versant Power**. We are committed to ensuring that all of our interconnections are designed, tested and energized in the safest manner possible. Versant Power's top priority is the protection of our customers, employees, contractors and the public. We have established rigorous safety protocols that must be followed at all times, and we provide ongoing training and support to ensure that our team members are equipped with the knowledge and tools necessary to maintain a safe work environment. We take our responsibility to promote safety seriously and we believe it is a shared responsibility that extends to all our stakeholders;
2. **Power Quality:** DER Facility interconnections must maintain Versant Power EPS power quality at acceptable levels outlined with the Interconnection Requirements.
3. **Reliability:** DER Facility interconnections must not diminish the reliability of the Versant EPS as mandated by the MPUC.
4. **Operation:** DER Facility interconnections must maintain the operational abilities of the Versant EPS.
5. **Standards**: DER Facility interconnections must meet Versant's Standards.

[1] As of the publishing date of this document, Versant Power is believed to have the highest solar DER penetration of any utility in the United States (total nameplate capacity as a percentage of peak load.)

1.2 Interconnection Requirements, DER Application Forms and Checklists

Copies of these DER Interconnection Requirements and all DER-related forms and supporting documents can be obtained from our website:

versantpower.com/energy-solutions/connecting-renewable-resources/distributed-generation-interconnection-process/

1.3 Versant Power Contact Information

The Versant Power DG Interconnection Team is the primary point of contact for interconnection of Generating Facilities to the Electric Power System.

- Email: **dginterconnections@versantpower.com**
- Mail:
  Versant Power
  Attn: DG Interconnections
  PO Box 932
  Bangor, Maine 04402-0932

1.4 Regulatory

The interconnection process for DERs is governed by federal and state regulations. The Federal Energy Regulatory Commission (FERC) has jurisdiction over the interconnection of wholesale generators to the transmission grid, while the Maine Public Utilities Commission (MPUC) has jurisdiction over the interconnection of DERs to the distribution system. The MPUC has established interconnection procedures under Chapter 324 that apply to all distributed generators connecting to the distribution system. Versant Power follows these procedures as well as its own standards in the interconnection process.

In addition to federal and state regulations, there may be local regulations that apply to the interconnection of distributed generators. Interconnection customers are responsible for complying with all applicable regulations and obtaining any necessary permits or approvals from federal, state and local authorities.

1.5 Scope and Limitations

Any exemptions to these requirements must receive written approval from Versant Power prior to interconnection. The criteria and requirements in the Interconnection Requirements are applicable to all DER technologies and to the primary and secondary voltages of the Versant EPS. DER Facility interconnections with radial primary and secondary distribution systems are the main emphasis of the Interconnection Requirements, although secondary network systems are also included.

The Interconnection Requirements were developed with reference to several standards and codes as listed in Appendix C and are more specifically based on the following standards and codes which may be updated from time to time:

- IEEE Std 1547-2018 Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
- National Electrical Safety Code (NESC)
- ISO-NE Default IEEE 1547-2018 Setting Requirements
- National Electrical Code (NEC)

The Interconnection Requirements specify the minimum requirements for the interconnection of a DER Facility with the Versant Power EPS. Depending on the circumstance, additional requirements may be applicable to the DER Provider to ensure that the final interconnection design meets all applicable Versant, municipal, national, and international standards and codes, and that the design is safe for the application intended.

The Interconnection Requirements do not address any liability provisions agreed to elsewhere by the DER Provider and Versant Power, or the applicable tariff or Versant Terms and Conditions.

Specific types of interconnection schemes, DER technologies and the Versant EPS may have additional requirements, standards, recommended practices, including other required documentation external to the Interconnection Requirements. Versant will engage the DER Provider to address these issues as required during the DER interconnection process.

The Interconnection Requirements are not a design manual nor a substitute for responsible engineering practice. All requirements listed within the Interconnection Requirements are minimum requirements. A DER Provider intending to interconnect to the Versant EPS is advised to hire a qualified professional engineer licensed by the State of Maine. It is essential that these technical resources have related engineering experience in Maine to ensure compliance with all State codes, standards and all other requirements directed by Versant Power. Given the complexity of an application, Versant Power reserves the right to request professionally stamped documentation for DER projects.

1.5.1 Momentary Closed Transition (Non-Parallel) Exclusions

The Technical Interconnection Requirements are intended primarily for DER Facilities planning to export power onto Versant's EPS. A DER Facility with DER(s) operating in parallel with the Versant distribution system for 6 cycles or less (Momentary Closed Transition), including open transition, only needs to follow the requirements described in Section 7.20.

1.6 RESPONSIBILITIES

1.6.1 Versant Power Responsibilities

Versant Power is responsible for:

1. Operating the Versant EPS within all governing laws, regulations, codes and standards, including licensing and the requirements of:
    - MPUC

- ISO-NE
- NESC
- All other applicable requirements and standards

2. Providing safe and reliable power delivery while ensuring that the DER Facility interconnection does not harm the Versant EPS or customers.
3. Developing, updating and enforcing the Technical Interconnection Requirements
4. Notifying affected customers of any relevant system changes and updated requirements in a timely manner.
5. Design, construction, maintenance and operations of the Facilities on Versant's side of the Interconnection Point of Common Coupling (PCC).

1.6.2 DER Provider Responsibilities

The DER Provider is responsible for the following:

1. Safely designing, constructing, operating and conducting proper maintenance of the DER Facility.
2. Employing a professional engineer licensed in the State of Maine to declare by stamp and seal that the DER Facility has been designed in accordance with the requirements of the Technical Interconnection Requirements, Versant Power site specific requirements, prudent utility practice and all applicable standards and codes.
3. Operating the DER Facility in compliance with all applicable codes and standards including licensing and the requirements of:
    - MPUC
    - ISO-NE
    - NESC
    - NEC
    - All other applicable requirements and standards
4. Operating the DER Facility only within the terms and conditions of the Operating Procedures.
5. Acquiring all required permits and licenses, such as municipal permits, approvals and inspections.
6. Ensuring the DER Facility is compliant with the Technical Interconnection Requirements and any other interconnection-related documents issued by Versant Power. If the DER Facility is determined to be non-compliant or is found to be harming the Versant EPS or customers, the DER Provider must suspend operation of the DER Facility until compliance can be proven with supporting documentation provided to Versant.
7. Making all necessary changes to the DER Facility and providing all supporting documents to Versant Power within 60 days of receiving written notification from Versant when changes such as configurations, protection and control schemes occur to the Versant EPS or in response to:
    - Safety concern
    - System configuration changes
    - New or revised standards
    - New or revised codes
    - Legislation changes

8. Obtaining Versant Power's prior written approval for all DER Facility changes, including interconnection equipment replacements, design modifications and setting changes. Any changes made without the prior written approval of Versant shall be deemed a violation of the Versant Terms & Conditions or the Interconnection Agreement and may result in immediate disconnection from the Versant EPS.
9. Installing, owning and operating adequate generator protection as well as protection for other equipment within the DER Facility. These protection schemes prevent damage from faults or abnormal conditions, which may originate at the DER Facility or from the Versant Transmission and/or Distribution Systems.
10. Protecting DER Facility equipment in such a manner that outages, restoration, short circuits or other disturbances on the Versant EPS do not damage that equipment. DER Facility protective equipment must also prevent excessive or unnecessary tripping that would affect the Versant EPS reliability and power quality of other customers as described in the Technical Interconnection Requirements.
11. All required changes and associated costs related to the interconnection of the DER Facility with the Versant EPS, regardless of where the change was initiated (e.g., Versant, MPUC, ISO-NE, NERC, or Federal Energy Regulatory Commission (FERC)). More specifically, the DER Provider is responsible for all interconnection costs, including but not limited to:
    - Studies
    - All related system upgrades
    - All project management and engineering required for the implementation
    - Commissioning and testing
    - Ongoing maintenance and DER Facility upgrades
    - All communication fees
    - Equipment settings and modifications
    - Testing of DER Facility equipment
12. While responsible for all interconnection costs, the DER Provider will not own the protective devices within any Versant-owned Facilities. All other infrastructure, excluding Versant-owned equipment (e.g., telecommunication interface), will be owned and maintained by the DER Provider. Additional Versant equipment may be required to be installed in the DER Facility, as determined by Versant on a case-by-case basis. The DER provider must provide the necessary space for Versant-owned interconnection equipment on the facility side of the interconnection PCC.
13. The interconnection POI and PCC may vary depending on both the type of the Versant EPS configuration where the DER Facility is to be interconnected and the service type (e.g., primary/secondary service, overhead line/underground cable, etc.), which will be determined during the DER interconnection process.

1.7 Interconnection Requirements

1.7.1 Interconnection Process

To avoid delays in the interconnection process, the DER Owner must provide complete and accurate information to Versant Power in a timely fashion at the start of the DER interconnection process. Any changes and/or incomplete information provided to Versant Power can result in significant delays.

The Technical Interconnection Requirements include references to the requirements for DER interconnection but do not address all site-specific protection and technical aspects of the DER Owner's facility and equipment. It is the responsibility of the DER Owner to ensure that requirements such as scoping, procurement, protection, installation, commissioning, operation and the maintenance of the DER Facility is complete and verified by all appropriate authorities. The DER Owner must have a professional engineer licensed in the State of Maine declare by stamp and seal that the DER Facility has been designed in accordance with the requirements of the Technical Interconnection Requirements, Versant Power site specific requirements, prudent utility practice and all applicable standards and codes.

An Interconnection Agreement between Versant Power and the DER Owner must be signed before energization of the DER Facility.

2 VERSANT POWER ELECTRIC POWER SYSTEM

Versant Power is a regulated electric transmission and distribution utility that serves approximately 165,000 customer accounts in northern and eastern Maine. Our service territory covers 10,400 square miles and includes 1,265 miles of transmission lines and 6,350 miles of primary distribution lines. Our electric power system consists of two service districts. Please refer to Figure 2-1 on the following page for a map of the Versant service territory and service districts.

The Bangor Hydro District (BHD) includes Hancock, Piscataquis, and Washington counties and most of Penobscot County. BHD covers primarily eastern Maine and includes distribution voltages ranging from 4.16kV to 34.5kV, as well as subtransmission voltages at 34.5kV and 46kV. BHD falls under the jurisdiction of ISO New England (ISO-NE).

The Maine Public District serves Aroostook County and a small portion of Penobscot County. MPD covers northern Maine and includes distribution voltages at 12.47kV and 34.5kV, as well as subtransmission voltage at 44kV and 69kV. MPD falls under the jurisdiction of the Northern Maine Independent System Administrator (NMISA).

At Versant Power, we are responsible for the safe and reliable operation of the electric power system, which is a system of poles, wires, substations, meters and other equipment. We take considerable pride in ensuring that our customers have access to electricity and we are committed to providing quality service.

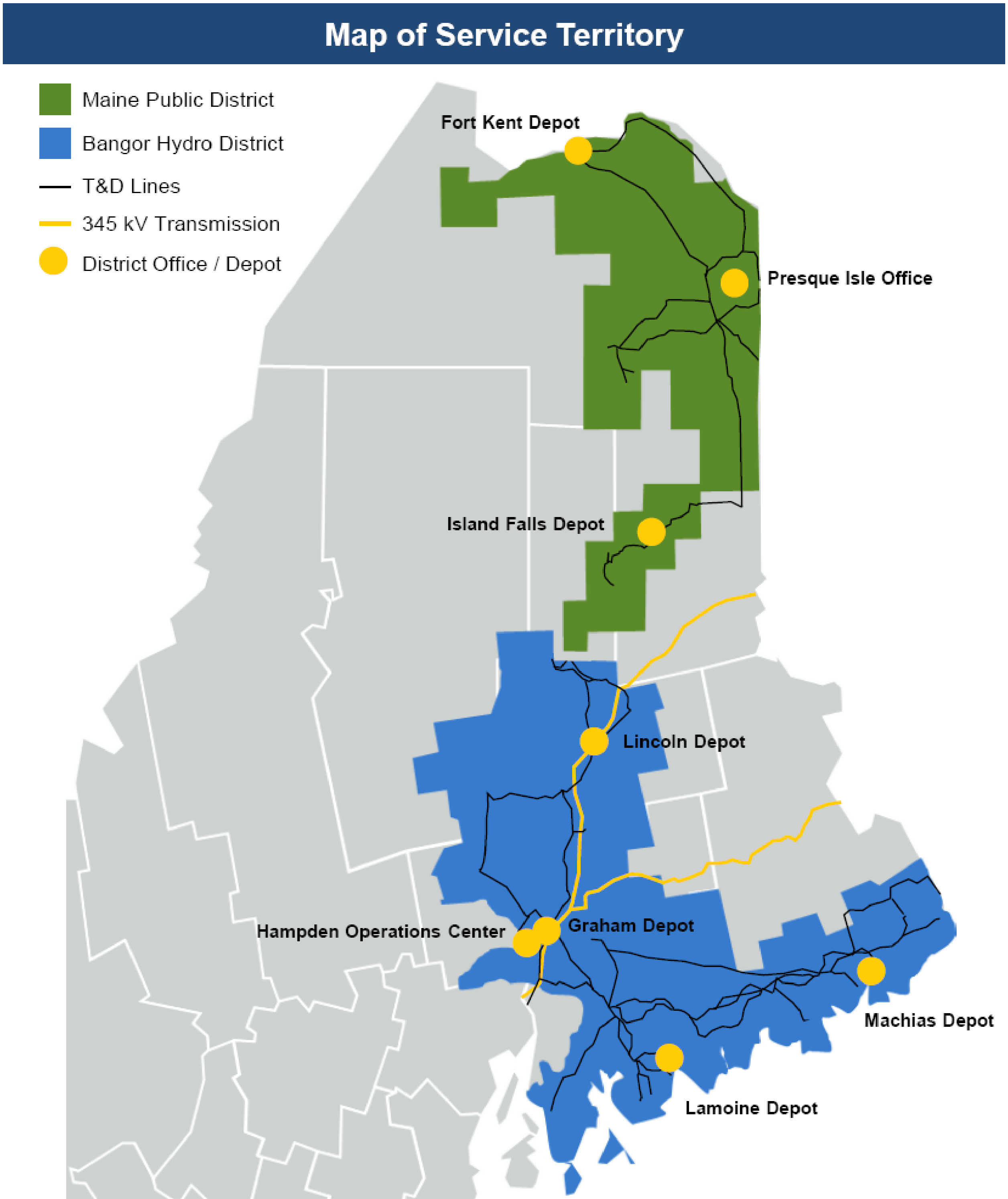


Figure 2-1: Map of Versant Power Service Territory

2.1 VERSANT POWER SYSTEM CONFIGURATIONS

This section provides details and constraints of the Versant EPS and an overview of system-specific planning and operational criteria.

2.1.1 Distribution System

Versant Power's distribution system includes subtransmission-sourced distribution substations typically with one power transformer, bus voltage regulators and two, three or four feeders. Larger capacity substations in urban areas may have load-tap-changing (LTC) transformers. Feeders are primarily radial and have several different nominal system voltages (all 3-phase 4-wire) depending on the area served: 34.5kV, 13.2kV, 12.47kV, 8.32kV and 4.16kV. The distribution system serves customers at both primary and secondary voltages. Most of the Versant service area is rural and may have limited DER hosting capacity especially considering the existing high penetration of DERs.

Feeders may have multiple normally open switching points or feeder ties to provide alternate power supply paths upon the loss of the original primary voltage source. The system also utilizes an extensive matrix of distribution automated switches, both inline switches and tie switches, working together to maintain electrical service to customers through operational schemes including feeder sectionalizing and restoration. The automated switches can also function as reclosers. Stand-alone reclosers and sectionalizers are common on all feeders in addition to inline fuses. The stand-alone devices often are part of fuse saving schemes that allow reclosing attempts to clear temporary faults before downstream coordinating fuses operate to clear permanent faults. This switching equipment is coordinated with protection and restoration schemes that can affect DER Facility interconnection requirements.

2.1.2 Subtransmission System

Versant distribution substations are served from the subtransmission system. Subtransmission voltages are 69kV and 44kV in the MPD service area, and 46kV and 34.5kV in the BHD service area. These lines are primarily configured radial as well. Significant DER penetration on a substation or from other generators fed from the same line may limit area DER hosting capacity without major subtransmission system upgrades.

2.1.3 Bulk Power Transmission System

The Versant Power Bulk Power Transmission System is the backbone of Versant's EPS. Transmission voltages are 345kV, 138kV (MPD only) and 115kV. Multiple interconnections to New Brunswick Power to the east, Hydro Quebec to the north, and Central Maine Power to the south serve to provide capacity and reliability to Versant's customers.

2.2 DISTRIBUTION VOLTAGE REGULATION & SERVICE VOLTAGES

Versant Power maintains standard nominal system voltages and service entrance voltages at all customer sites in accordance with the standard nominal system voltages established by ANSI C84.1. Versant maintains and operates its system to conform to the voltage variation ranges established by ANSI C84.1 for Voltage Range A and

Voltage Range B. A variation of +/-5% from nominal voltage is maintained. Table 2-1 and Table 2-2 below set forth the voltage variation limit requirements specified by the current version of ANSI C84.1 (ANSI C84.1-2016), Range A and Range B.

Versant's system is designed, maintained and operated so that Service Voltages will generally be within the Range A limits. Infrequent and limited periods during which Service Voltages are outside Range A limits will remain within Range B limits. When Service Voltages occur that are outside Range B, Versant takes prompt corrective action to restore Service Voltages to acceptable levels.

Table 2-1: ANSI C38.1 Range A (Normal Operating Range)

Established Standard Service Voltage	Minimum Voltage	Maximum Voltage	Type of Service
120/240	114/228	126/252	Single Phase
208Y/120	197Y/114	218Y/126	Single or Polyphase
480Y/277	456Y/263	504Y/291	Polyphase

Table 2-2: ANSI 84.1 Range B (Abnormal Range)

Established Standard Service Voltage	Minimum Voltage	Maximum Voltage	Type of Service
120/240	110/220	127/254	Single Phase
208Y/120	191Y/110	220Y/127	Single or Polyphase
480Y/277	440Y/254	508Y/293	Polyphase

Distribution system voltage regulation is achieved through the operation of automatic load tap changing transformers or bus voltage regulators at Versant substations. Line regulators and shunt capacitor banks at locations along distribution feeders are also used to provide additional regulation to the system. With the onset of large inverter-based solar DER Facilities and high DER penetration throughout the Versant distribution system, DER Volt/Var operation, which is typically required, further serves to augment voltage regulation.

2.3 Voltage Unbalance

The Versant Power EPS is planned to limit voltage unbalance below 5% under normal operating conditions. Voltage unbalance is measured per the equation below:

Voltage unbalance (%) = 100 x V2/V1

Variables:
V1 = average of line-to-neutral voltage on each phase
V2 = maximum deviation from V1

The DER Facility must be interconnected to the Versant EPS in a manner that ensures voltage balance can be maintained within this threshold. See Section 6.4 for more details related to voltage and current unbalance conditions.

2.4 Frequency

The Versant EPS operates at 60Hz (Hertz) alternating current (AC) as part of the Northeast Power Coordinating Council that is regulated between a range of 59.4Hz and 60.6Hz.

ISO-NE establishes the default abnormal frequency trip settings and abnormal frequency ride-through requirements for DERs connected to the Versant EPS.

2.5 Harmonics

Versant Power sets requirements on acceptable harmonic and flicker limits for interconnected DERs. More detailed information on these requirements can be found in Section 6 DER Protection & Control Requirements.

2.6 Fault Levels

Throughout Versant's primary distribution system, regardless of the voltage class or geographic area, the maximum fault current level through any element of a Versant feeder cannot generally exceed 8kA, including DER generation contributions. The maximum allowable fault level can be a factor that limits the individual and aggregate size of the DER interconnection request.

2.7 Grounding

The Versant Power distribution system is a four-wire, multi-grounded neutral system with a wye-grounded configuration. The Versant distribution system is an effectively grounded system in accordance with IEEE C62.92.

2.8 Maximum DER Facility Size

The maximum size of a DER Facility that can be interconnected to Versant's distribution system will be assessed by Versant on a case-by-case basis when Versant receives a DER interconnection request. The maximum size varies depending on the substation, feeder and specific Point of Interconnection (POI) on the feeder where the proposed DER is interconnected.

The following detailed technical factors are considered when determining the maximum interconnectable DER size:

Versant Distribution System:

- Voltage class of the feeder
- Feeder and transmission topology
- Thermal limits of conductors and equipment
- Fault level
- Protection schemes and device coordination
- Feeder and substation loading
- Voltage regulation
- Reactive support
- DER penetration
- Interaction with other DER (Inverter-Based, Synchronous & Induction Resources)

DER Owner:

- DER size
- DER location
- DER technology
- DER protection scheme
- DER reactive support

In general, due to subtransmission and substation equipment limitations as well as protection limits at the substation, feeders may only accommodate a DER aggregate up to approximately 10 MW (or less) to limit reverse power.

Substation transformer reverse power flow (RPF) capacity is limited. Reverse power limitation criteria is the subject of research on a global basis. Versant will be working with the MPUC to determine appropriate methods to set the RPF criteria using the latest available research in 2026. The research available to date indicates that reverse power flow caused by DERs has the potential to create a significant negative impact on transformers not designed specifically for it. One paper states that the resulting thermal stress at certain flow levels becomes so great that, "such conditions are not thermally sustainable."

3 DER INTERCONNECTION PROCESS OVERVIEW

This section describes the required process by which a DER is connected to Versant Power's electric power system (EPS). The interconnection process is important to ensure that the distribution system remains stable and reliable and to ensure the safety of the public and utility personnel. Versant Power is committed to working with DER developers to ensure that the interconnection process is efficient and effective while maintaining the highest standards of safety and reliability.

The following sections describe the process of siting DER resources, the submission of required documentation, the application review and screening process, a description of available optional studies and catalysts for restudies. Our website contains flowcharts depicting the major steps within the DER interconnection process for both the BHD and MPD service areas.

3.1 SITING DER RESOURCES

The process of siting a DER Facility involves assessing the physical and electrical feasibility of a location. To aid in the preliminary evaluation of siting of DER facilities, Versant Power provides a Hosting Capacity Map on our website that indicates the estimated available DER capacity on the electrical distribution system. We also provide power transformer capacity for each of our distribution substations. You can request a Pre-Application report to obtain additional detailed system information about potential interconnection locations.

3.1.1 Hosting Capacity Maps

A Hosting Capacity Map is available on our website for our entire service area. The map provides information to assist in the determination of suitable installation locations. Please note that the Hosting Capacity Map is for information purposes and does not guarantee a low-cost interconnection. The generation capacity limits displayed on the maps are based on common reliability issues that may require significant upgrades; however, they do not account for all upgrades that may be necessary for safe and reliable power system operation. For example, if two locations were identified based upon land availability, and the hosting capacity map showed that Site 1 had less than 1,000 kW of capacity and Site 2 had greater than 5,000 kW of capacity, then installation at Site 2 would likely have a lower interconnection cost.

The Hosting Capacity Map should be used as an aid in screening potential interconnection locations, however, the maps may not fully represent the interconnection capacity potential of a given location. Note that the maps do not reflect all generation that may exist in the queue, be under contract, be under construction, or that were recently interconnected. Customers seeking to interconnect a DER Facility may request a Pre-Application Report to obtain more information about the circuit and PCC, as described in Section 3.1.2.

3.1.2 Pre-Application Report

An optional Pre-Application Report can be requested by potential applicants developing projects 500kW in size and greater. The report provides applicants information about system conditions at a proposed PCC. To request the report, applicants must complete the Pre-Application Report request form and send it to Versant Power with a nonrefundable processing fee defined in Table 3-1 below.

Within fifteen (15) business days of receipt of a request, Versant Power will provide a Pre-Application Report. Please refer to MPUC Chapter 324 for more details about DER information required and what information is provided.

3.2 Interconnection Application Documentation

The interconnection process begins with the submission of a complete interconnection application to Versant Power and upon receipt of all required information. This section provides descriptions to assist in the provision of satisfactory documents for the interconnection process. Additionally, Appendix E provides a full developer checklist of interconnection application, equipment specifications and design document requirements.

3.2.1 Interconnection Application

The Interconnection Application includes basic information about the proposed project such as the type and size of the generator, the location of the project and the expected date of operation. Note that the required interconnection application depends upon the DER's interconnection level as follows:

- Level 1 Generators require the Level 1 Standard Interconnection Application
- Level 2, 3 and 4 Generators require the Level 2, 3, & 4 Standard Interconnection Application

As part of the application process, the following must be provided with the Interconnection Application:

- Demonstration of Site Control for the proposed installation site
- A proposed schedule for the in-service date
- Technical specifications for each piece of major equipment utilized in the installation
- Payment of the non-refundable application fee as set forth in Table 3-1.

Table 3-1: Interconnection Application Fees

Level	Generator Applicability	Full Site Nameplate Rating	Application Fee	Per Study Fee
Pre-Application (Optional)	All Generators	-	$300	N/A
Level 1	Inverter-Based Generators	≤ 25 kW	$100	N/A
Level 2	All Generators	≤ 2,000 kW	$100 + $2/kW	Time Based
Level 3	Non-Exporting Generators	≤ 10,000 kW	$100 + $3/kW	Time Based
Level 4	All Generators Not Subject to FERC Jurisdiction	N/A	$3,000	Time Based

The application, along with applicable fees set forth by the MPUC, should be submitted via email to the Versant Power DG Interconnections Team. Please refer to Versant's website where all DER-related forms can be found.

The proposed Point of Interconnection (POI) must be an existing or currently planned distribution circuit. For three-phase interconnections, there must be three phases existing at the source of the circuit. The generator will be connected to the distribution and/or substation serving the area where the POI is located.

Note that changes to any information provided by the Generating Facility described in the application, including any design changes and capacity increases, may result in restarting the process with a new application. Applicants must obtain Versant Power's written approval before making any modifications to the generating facility described in the application. A completed project Change Request form along with all necessary documentation will need to be submitted for any design changes.

3.2.2 Single-Line Diagram

The Single-Line Diagram is an electrical schematic drawing depicting the complete proposed system design. Minimum specifications will vary depending on the Generator Level, Nameplate Rating, and Type, but typically include:

- All electrical components, including but not limited to:
  - Utility revenue meter
  - Utility owned recloser (when required)
  - Customer-owned and utility-accessible gang-operated airbreak disconnect switch with visible blades
  - Customer-owned recloser
  - Effective grounding (or supplementary grounding) device
  - GSU transformer(s)
  - Inverter settings (mandatory for generators ≥100 kW)
- All protective relaying devices and relay settings proposed for the installation
- All primary and secondary protective interrupting devices
- The impedance values of all AC components

The plan must also indicate the point of demarcation between Versant Power and customer-owned equipment (the PCC).

Refer to Appendix E for all requirements and details required to be shown on the single-line diagram. All single-line diagram details are required in order to avoid rejection of the application.

3.2.3 Site Plan

The Site Plan must show the proposed location of the generator and interconnection equipment, including POI coordinates (WGS 84 datum), site address, access roads, utility turn-around, fencing, and any necessary utility infrastructure such as the utility recloser, revenue meter, interconnecting utility pole and pole number. The plan must also indicate the point of demarcation between Versant Power and customer-owned equipment (the PCC).

Site plan requirements are also provided in Appendix E.

3.2.4 Generator Specifications

To ensure a successful interconnection process, the customer must submit documents to Versant Power providing a detailed description of the DER characteristics. The required information will vary depending on the type of DER being interconnected; however, some examples of required information include:

- Manufacturer datasheets
- Short circuit capability
- Real power (P) and reactive power (Q) capability
- Voltage support capabilities (e.g., Volt/Var, Volt/Watt, etc.)
- Certifications (e.g., IEEE 1547, UL 1741 SB)

Note that while some manufacturer datasheets or manuals will include all required information, others will not. It is the responsibility of the customer to ensure that all necessary data are submitted to avoid delays in the interconnection process.

Additionally, PSCAD models and corresponding inverter firmware information are required for all generators entering a System Impact Study (SIS). A checklist of PSCAD data requirements for common types of DER facilities can be found in Appendix G. A PSCAD model shall be provided for the PPC when included in the design or required to be included as a result of the SIS.

3.2.5 Application Disputes

Versant Power will work with the DER Applicant to promptly resolve all disputes arising during the application process. If informal efforts do not result in a resolution of the dispute, the more formal dispute resolution procedures set forth in Chapter 324 are available.

3.3 Application Review and Screening

The application review and screening process consists of Versant Power reviewing the provided interconnection application, a screening process to determine the generator's interconnection level, and a review of any transmission-level interconnection requirements.

The following topics are discussed in this section: Application Review, Interconnection Level Determination, and Transmission-level Interconnection Requirements. This section outlines the process by which Versant Power will review and screen applications from DER developers to ensure safe and reliable operation of the electric power system.

3.3.1 Application Review

The following steps outline the application review process for interconnecting a DER to Versant Power's electric power system:

1. Versant reviews the application materials to verify that the application is complete. If any application information is missing, the Versant DER Facilitator will notify the Applicant within five (5) business days. The DER Facilitator will work with the Applicant to identify what is needed to complete the package and will place the application in an "on hold" status pending receipt of the required information. Versant will review the application material and may comment on technical aspects, but Versant is not responsible for the accuracy of the interconnection design, drawings, or technical specifications.
2. For Level 4 interconnection requests, the Applicant must document Site Control before the screening process can continue.
3. Versant conducts an application screening process per Appendix E.
4. Following notice of a complete application, the customer may request a scoping meeting at a mutually agreed upon date.
5. If an Interconnection Feasibility Study is requested, the Company will provide an Interconnection Feasibility Study Agreement including an outline of the study and a non-binding good faith estimate of the cost to perform the study. The

Applicant then provides the completed agreement along with the appropriate associated payment to the DER Facilitator.

6. If the Applicant requests that the Interconnection Feasibility Study evaluate multiple potential points of interconnection, additional evaluations may need to be performed. The Applicant is responsible for the costs of these additional evaluations.

3.3.2 Interconnection Level Determination

Interconnection levels are determined based on the aggregate size and complexity of the proposed DER Facility. Each interconnection level is associated with a specific set of screening requirements and possible studies that must be completed before the interconnection can be approved.

The interconnection process begins with a screening process to determine the appropriate interconnection level for the proposed DER Facility. The level screening is based on the capacity of the facility, the type of technology and the location on the distribution system. Level screenings are conducted in accordance with the Maine Public Utilities Commission (MPUC) Chapter 324 screens and Versant Power screens in accordance with the four defined interconnection levels. Applicability of screening to the first three levels is shown in Table 3-2:

Table 3-2: Level 1, 2 and 3 Screens

Interconnection Level	**Chapter 324 Screen Applicability**														**Next Level****
	7 A	**7 B**	**7 C**	**7 D**	**7 E**	**7 F**	**7 G**	**7 H**	**7 I**	**7 J**	**8**	**9 A**	**9 B**	**9 C**	
Level 1	X				X				X		X	X *			Level 2, 3 or 4
Level 2	X	X	X	X	X	X	X	X	X	X	X	X *	X *	X *	Level 3 or 4
Level 3		X	X	X	X	X	X	X		X	X	X *	X *	X *	Level 4

*Must pass screen if interconnecting to a distribution area or spot network.
**Customer may request that applications continue to be processed at Next Levels shown upon screen failure(s).

Level 4 interconnections are all other generators not subject to Chapter 324 screens and FERC jurisdiction. Generators in this category require additional study to ensure that they do not result in adverse impacts to the electric power system. Versant will conduct a Level 4 document screening (review) process and some additional basic evaluations including system capacity limitations (substation and feeder), stiffness ratio and existence of Alternate Load Transfer (ALT) schemes and Underfrequency Load Shed (UFLS) schemes.

Versant Power and the MPUC may require additional studies or modifications to the interconnection process based on the specific characteristics of the proposed DER Facility and its location on the distribution system as outlined in Section 4.7.

3.3.3 Level 1 and 2 Screening Results

For Level 1 and 2 interconnection applications passing screens that do not require System Impact and Facility Studies of the proposed DER Facility in which the Applicant decides to proceed, the Applicant may execute an Interconnection Agreement and proceed with the interconnection process.

For a Level 1 or 2 interconnection application that fails one or more screens and is not approved, the Applicant may opt to have an Additional Review unless it can be pre-determined by Versant that system upgrades to mitigate DER impacts would exceed the minor upgrades threshold. Failure of passing an Additional Review will require withdrawal of the application or re-applying as a Level 3 or Level 4 project. Additional Reviews include the following screens:

- Generation to Minimum Load Ratio (for Load Rejection Overvoltage)
- Stiffness Ratio
- Steady State Voltage Analysis
- Risk of Islanding
- Output Drop Assessment
- Underfrequency Load Shed (UFLS) Scheme Impact
- Substation Transformer Capacity
- Conductor Thermal Evaluation
- Project Path Device Thermal Evaluation
- Effective Grounding
- Protection Evaluation
- Harmonic Compliance
- Interconnection Transformer

3.3.4 Impact of DER on Transmission

Level 4 interconnections may be required to participate in a regional cluster study to show no adverse impacts to the transmission system. Refer to Section 4.8 for more information on cluster studies and ISO-NE requirements.

Versant may perform other area transmission studies as necessary to determine impacts of DER interconnections, particularly if areas experience elevated levels of DER penetration.

3.3.5 Transmission-level Interconnection Requirements in BHD

Transmission level interconnections, which are administered by ISO New England in the BHD, are segregated into two size levels to determine the interconnection process. Generators 20 MW or less will follow the Small Generator Interconnection Process (SGIP) and generators larger than 20 MW will follow the Large Generator Interconnection Process (LGIP). These processes can be found on the ISO-NE website.

Several of Versant's lines serving distribution customers are designated FERC jurisdictional due to interconnected market-participating DER facilities or if the line meets other FERC definitions to be designated as a transmission facility. If a DER interconnection is proposed for any of these lines, the ISO-NE process above must be followed. To interconnect as a DER Facility to a subtransmission line under the Chapter

324 process, the DER Facility must connect directly to an existing three-phase distribution tap sourced by the subtransmission line. To determine if a line is FERC jurisdictional, please refer to the transmission maps at the Versant website here: https://versantpower.com/media/65215/Maps-of-Transmission-Circuits.pdf.

Level 2, 3 and 4 Interconnection applications in the BHD must also notify ISO New England and follow their requirements in Planning Procedure PP5-1: Procedure for Review of Governance Participant's Proposed Plans. All projects over 1 MW require i.3.9 approval. Depending on the location and queue position of your project, there are varying levels of transmission analysis required to secure i.3.9 approval, from a Level 0 non-comprehensive review through a Level 3 cluster study. Requirements for new generation or changes in output are summarized in Section 2.1 at: https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp05_1/pp5_1.pdf.

3.3.6 Transmission-level Interconnection Requirements in MPD

All transmission-level interconnections in the MPD are administered by Versant Power under its filed Open Access Transmission Tariff (OATT) and are found on Versant's website.

3.3.7 Level 4 DER Study Requirements

Following the completion of the application review, and assuming the Applicant decides to proceed, a System Impact Study is required for all Level 4 interconnections.

A Feasibility Study (FS) is an optional study with reduced scope and cost that seeks to identify the need for significant upgrades prior to the full SIS. For example, the FS could identify a significant conductor upgrade due to thermal limitations within the existing system. It is important to note that the FS may not identify all required upgrades and significant upgrade(s) may still be required per the SIS.

The Applicant may skip the FS and proceed directly to the SIS. If the Applicant elects to have an FS performed, upon receipt and review of the FS study results, the Applicant will have the opportunity to cancel their application or proceed with the complete SIS process.

Additional information for both the FS and SIS is provided in Section 4.1 and Section 4.2, respectively.

In addition to identifying possible system upgrades to ensure the safe and reliable operation of Versant's electric power system, the SIS may also identify required follow-on studies, such as:

- Protection Coordination Study (PCS)
- Volt/Var Operational Study (VVO)

Additional information for both the PCS and VVO can be found in Section 4.3 and Section 4.4, respectively.

3.4 Level 4 DER Restudy Requirements

As noted in Section 3.2, any design changes require written approval from Versant Power. Additionally, if a design change occurs following the required system studies, Versant shall review the design change(s) and determine whether a restudy is required. It is important to note that if other queued generators, occurring later in the interconnection queue, are affected by the design change and a subsequent restudy is required, the Applicant will be responsible for covering the restudy costs for all later queued Level 4 generators connected to the same substation.

Generally, a project design change modifying the project kW size can reduce the maximum export amount by up to 60% without restudy as long as all else remains the same, i.e. any system upgrades as identified in the SIS. All instances will be subject to an engineering review before a final determination is made whether a restudy can be waived.

For guidance as to whether a design change will require a restudy, please refer to Appendix F.

3.5 Interconnection Agreement

The Applicant must execute an Interconnection Agreement and provide payment in full for the construction of any required Electric Power System modifications. The execution of the Standard Interconnection Agreement and payment by the Applicant authorizes Versant Power to initiate the design phase (Facilities Study), procure material and equipment, and perform the associated work.

3.6 Project Construction

The Applicant and Versant Power shall undertake the construction of the necessary Interconnection Facilities and Electric Power System modifications (Distribution Upgrades) in strict accordance with the design and engineering drawings, construction standards, documents, and terms stipulated in the interconnection agreement. It is expected that all work shall be carried out in a professional and diligent manner, with the highest regard for safety, quality and compliance with applicable regulations and standards.

Versant will provide project management and construction management oversight throughout the entire design, construction and commissioning process.

3.7 Commissioning and Pre-Parallel Testing

Facility commissioning and pre-parallel testing is required to ensure the Generating Facility operates as expected and does not adversely impact the safe and reliable operation of the Electric Power System.

1. Before operating in parallel with the Electric Power System, the Generating Facilities and associated interconnection equipment must be inspected and tested to ensure compliance with the facility design, impact study requirements, follow-on study requirements and for proper operation.

2. The Applicant should notify the Company of a proposed date for commissioning testing, including a test procedure, at least 10 business days before the proposed test date.
3. If significant problems arise preventing the conclusion of testing, the Company and the Applicant will schedule a mutually acceptable retest date.

Versant's support costs for the commissioning process will be borne by the Applicant. The process includes a review of the as-built documents including single-line and three-line diagrams, equipment specs, equipment settings and relay test reports as well as witnessing the commissioning testing as required in the Testing and Commissioning Section 10. Charges will accrue for the initial and any subsequent Company visits that are required for the commissioning testing to reach satisfactory completion. The Applicant will be charged only for company personnel and its designated representatives required to conduct and witness the testing.

There will be no charge for Versant personnel to witness the commissioning testing of Level 1 inverter-based Generating Facilities if required, provided that the testing is completed in one visit. If the Applicant is not ready for the testing to occur on the first visit, or if the testing cannot be completed or must be repeated because of a problem on the first visit, then Versant will charge the Applicant to witness commissioning testing on subsequent visits.

3.8 Required Agreements

An Applicant seeking to establish an electrical interconnection with the Company must have all necessary agreements executed before parallel operation will be authorized. The agreements an Applicant may need to complete (depending upon the size of the proposed Generating Facility) include:

1. Study Authorization Agreement(s) (Feasibility Study, System Impact Study, and/or Facility Study).
2. Standard Interconnection Agreement signed by the Applicant and the Company before parallel operation can commence (required for all Generating Facilities). For generators utilizing renewable resources primarily for internal use and qualifying for net metering, a Net Energy Billing Agreement should be completed in addition to the Standard Interconnection Agreement.
3. Aggregation Agreement must be completed if the facility would like the Standard Offer Provider to purchase the output of their facility. All facilities with less than 5 MW output qualify for this arrangement as set forth in Section 21 the Company's Terms & Conditions on file with the MPUC. Generators who qualify for the net metering option may choose the Aggregation option instead of net metering (or make use of any other applicable selling option) but may only change between options a maximum of once per year.

If an extension to a Company-owned line is required in order to accommodate the interconnection, the Company will obtain suitable easements or rights of way for the extension and the Applicant will be responsible for all costs incurred.

3.9 Final Acceptance, Cost Reconciliation, Authorization to Interconnect

If the interconnection is not approved, the Applicant will need to take corrective action in order to obtain authorization to interconnect to the Electric Power System.

Prior to formal authorization of the interconnection, the Applicant will provide the Company with updated drawings and prints showing the Generating Facility as approved for normal operation. The single-line and three-line drawings must be "as built" quality and include all changes that were made since completion of studies and during construction and testing. The Applicant will provide the Company a Certificate of Completion and must obtain a release from the municipal electrical inspector or the authority having jurisdiction.

When the interconnection is approved, the Company will provide notification stating that the Generating Facility is allowed to commence parallel operation to the Electric Power System.

The Company will provide a final cost reconciliation and an invoice for any balance due or a reimbursement for overpayment of any deposit.

3.10 Costs of Interconnecting a DER Facility

3.10.1 Fees

Versant Power will provide an estimate of the cost of any required Feasibility Study, System Impact Study or Facility Study.

3.10.2 Interconnection Equipment Costs

The Applicant is responsible for the actual construction cost of the Interconnection Facilities and Distribution Upgrades to the extent required by MPUC Chapter 324. They are also responsible for expenses, including overheads, associated with owning, operating, maintaining, repairing and replacing the Interconnection Facilities and Distribution Upgrades. An Operating & Maintenance fee established by the MPUC is also assessed based on the installation cost.

3.10.3 System Modification Costs

The Applicant is responsible for all associated costs incurred by the Company in designing and constructing modifications to the Electric Power System that are required to accommodate the interconnection. Any costs associated with protection upgrades or modifications deemed necessary based on Good Utility Practice in order to accommodate the output from the generator shall be the responsibility of the Applicant. Payment of the estimated cost of the modification is required before work will commence. Any incremental expenses incurred to operate and maintain the required upgrades, beyond what would be required without the interconnection, will be the responsibility of the Applicant. These O&M charges will be based on a calculation using the additional equipment installation cost and will be billed monthly.

3.10.4 Applicant Challenge to Costs

If an Applicant believes that the Company has charged the Applicant for costs that are not reasonable for the work performed, or costs that are not related to the Applicant's interconnection, or are not related to the Company's costs of analysis, design and system work to accommodate the interconnection, then the Applicant may challenge such costs, provided that:

1. The Applicant has paid the Company all billed costs, including the disputed costs, in a timely manner.
2. The Applicant provides written notice to the Company within 10 business days of the receipt of an invoice for disputed costs, specifying the disputed costs and the reasons that the Applicant believes it should not be required to pay such costs. The dispute resolution procedures (refer to the MPUC's Chapter 324 Small Generator Interconnection Procedures) shall then be applicable to resolve the amount, if any, of the disputed costs that the Company shall return to the Applicant.

3.10.5 Insurance Requirements

The interconnection customer shall comply with all applicable insurance requirements imposed by the State of Maine and by Versant Power. Refer to MPUC Chapter 324 for insurance levels per type of Generating Facility.

4 DER Studies

This section describes the study types and processes used to evaluate DER seeking to interconnect to Versant's Electric Power System and the associated upgrades required to mitigate criteria violations triggered by their interconnections. Applicability of study types for a given generator interconnection level can be referenced in Section 3.3.2. High generation-to-load ratios and low stiffness factors may be a cause for concern.

The following sections describe the typical scope of work for a Feasibility Study, System Impact Study, Protection Coordination Study, Volt/Var Operational Study, and Facilities Study. Additionally, this section covers typical upgrades needed to mitigate violations and considerations that may need to be addressed during the interconnection process.

4.1 Feasibility Study (FS)

The Feasibility Study (FS) is an optional study that may be conducted if the customer wants to gain an understanding of potential upgrade costs associated with an interconnection without performing a full System Impact Study (SIS). The primary focus of the FS is to:

1. Assess compliance of the proposed project design with requirements of distributed generation interconnecting to the Versant Electric Power System according to the interconnection requirements.
2. Assess the high-level steady state impacts of the proposed project on the distribution systems served from the interconnecting substation.
3. Identify distribution system and substation upgrades that may be necessary to complete the interconnection of the project.

FS scope is subject to change depending on various interconnection factors, but in general, the following scope is evaluated:

- Design review
- Effective grounding analysis
- Fault current analysis
- Thermal analysis
- Voltage analysis
- Risk of islanding screening
- Load rejection overvoltage screening
- High level protection evaluation

Note that a full SIS is required regardless of whether an FS is performed.

4.2 System Impact Study (SIS)

The System Impact Study (SIS) is a required study for all Level 4 interconnections. The primary focus of the SIS is to:

1. Assess compliance of the proposed project design with requirements of distributed generation interconnecting to the Versant EPS according to the Technical Interconnection Requirements.
2. Assess the steady state impacts (Standard Study) of the proposed project on the distribution systems served from the interconnecting substation.
3. Assess the protection impacts (Protection Coordination Study [PCS]) of the proposed project on the distribution systems served from the interconnecting substation.
4. Assess the time domain impacts (Time Domain Study [TDS]) of the proposed project on the distribution systems served from the interconnecting substation.
5. Identify distribution system and substation upgrades that may be necessary to complete the interconnection of the project.

The Standard Study includes an evaluation of the following items:

- Design review
- Substation transformer loading evaluation
- Thermal evaluation
- N-1 evaluation
- Voltage evaluation
- Reactive evaluation
- Output drop evaluation

The Protection Coordination Study includes an evaluation of the following items:

- Fuse savings scheme impacts and upgrades
- Effective grounding evaluation
- Stiffness ratio calculation
- Device rating evaluation
- Device setting evaluation
- Device coordination evaluation

The Time Domain Study includes an evaluation of the following items:

- Load rejection overvoltage analysis
- Ground fault overvoltage analysis
- Risk of islanding evaluation
- Underfrequency load shed impact assessment
- Volt/Var interaction assessment

A PSCAD model validation process will be completed prior to commencement of the SIS to ensure the PSCAD model used to represent the project inverter(s) is sufficient for use. Projects utilizing Power Plant Controllers (PPCs) will need to provide a PSCAD model of the PPC as well.

Once the SIS process is complete, all results, required upgrades and an approximate ±25% cost estimate of any identified Interconnection Facilities and Distribution Upgrades are summarized and relayed to the customer. A results meeting is then scheduled between the customer and Versant Power to review and discuss the study results and upgrade estimate. After this meeting, the customer has 15 business days to provide an intent to proceed with the project. Failure to notify Versant of an intent to proceed within 15 business days may result in removal of the project from the queue.

4.3 Protection Coordination Study (PCS)

The Protection Coordination Study (PCS) is conducted within a project's SIS, as noted in the previous section. Any items that were not covered in the SIS, such as inrush flagging in the SIS, will be considered during this detailed engineering design phase. If GSU transformer inrush is shown to affect upstream protection schemes, design changes to the proposed DER Facility are typically necessary to mitigate transformer inrush.

Following the SIS (and detailed engineering design phase PCS if necessary), the customer is notified of protection settings required to be implemented on the project recloser as well as any upgrades differing from those specified in the SIS.

4.4 Volt/Var Operational Study (VVO)

The Volt/Var Operational (VVO) study is conducted within a project's detailed design phase following the customer's intent to proceed after SIS completion and Versant receiving 100% payment of the upgrade estimate. The primary focus of the VVO study is to:

1. Perform time series simulations (long-term dynamics) to assess the time-based impacts of the proposed project and its respective upgrades on the distribution system served from the interconnecting substation.
2. Optimize and improve Volt/Var settings previously identified in the project's SIS and ensure all proposed inverter settings are feasible according to manufacturer technical specifications.
3. Optimize existing and/or proposed regulating device settings.
4. Optimize proposed reactive compensation device settings.

The VVO study includes an evaluation of the following items using CYME:

- Worst case circuit loading determination
- Time series analysis
- Evaluation of project Volt/Var settings improvements
- Evaluation of existing and/or proposed regulation device settings improvements
- Evaluation of reactive compensation device settings improvements

Following the VVO study, the customer is notified of Volt/Var settings required to be implemented on the project inverters or Project Power Plant Controller (PPC), if applicable. The reactive compensation design may also be revised if necessary.

4.5 FACILITIES STUDY

The Facilities Study is an optional study that represents a project's detailed design phase which determines the final scope and estimated costs of required modifications and upgrades to the Versant EPS and/or a Generating Facility. The primary focus of the Facilities Study is to:

1. Complete the engineering design work for the project to be ready for construction phase.
2. Prepare an updated upgrade estimate.
3. Revise the project schedule.

Facilities Study scope is subject to change depending on interconnection factors, but in general, the following scope is evaluated:

- Gather all data related to the project including interconnection details, Interconnection Facilities, Distribution Upgrades and results from the SIS.
- Complete the PCS and VVO studies as required.
- Develop a final scope of work for the Interconnection Facilities and Distribution Upgrades.
- Complete all engineering design work, documents and work packages for line, substation, Interconnection Facilities and Distribution Upgrades.
- Revise the original upgrade estimate per the final scope of work.
- Revise the project schedule as necessary.

Upon completion of the Facilities Study, Versant shall provide the Applicant with the construction cost estimate and anticipated completion date for the required modifications to the EPS.

4.6 TYPICAL UPGRADES

The majority of required upgrades are determined in a project's SIS and are further refined in the corresponding detailed design studies. The following Table 4-1 outlines typical upgrades used to mitigate adverse impacts:

Table 4-1: Typical Upgrades Resulting from DER Studies

Upgrade*	Adverse Impacts Mitigated	Installation Location
Line reconductoring	Thermal overloads Voltage violations	VP system
Substation transformer replacement	Transformer loading violations	VP system
Regulation settings changes	Voltage violations Excessive device operations	VP system
Switched reactive compensation capacitor	Reactive draw from VP system	VP system
Direct transfer trip (DTT)	Risk of islanding	VP system
Line recloser	Protection degradation	VP system
Underfrequency load shed scheme (UFLS) relocation	Protection degradation	VP system
ALT scheme integration	Load transfer scheme mis-operation	VP system
Project Volt/Var control**	Voltage violations	Project site
Power plant controller (PPC)	Voltage violations Adverse Volt/Var interactions Excessive device operations	Project site
Surge arresters	Load rejection overvoltage Ground fault overvoltage	Project site
Grounding bank	Load rejection overvoltage Ground fault overvoltage	Project site
*Costs will vary depending on upgrade specifications. **Typically required for projects 500 kW and greater. Power factor limits may apply which could lead to additional system upgrades.		

Note that solutions for adverse impact mitigation may vary with the Project design and/or interconnecting network.

4.7 Additional Considerations

While the previous sections outline the general study processes and resulting upgrades, additional considerations may be required for projects with atypical interconnection characteristics. Some examples include:

- Projects interconnecting to FERC-jurisdictional lines may require additional transmission studies (see Section 3.3.5 for BHD projects and Section 3.3.6 for MPD projects).
  - Projects interconnecting in the BHD are subject to ISO-NE criteria
  - Projects interconnecting in the MPD are subject to NMISA criteria
- Projects interconnecting to networks with known or anticipated harmonics issues may be subject to additional studies and upgrades to mitigate generator harmonic injections.

- Projects proposing to interconnect at locations hosted by feeders that are already at maximum DER capacity may be required to build new express feeds for interconnection.
- Projects interconnecting to networks with UFLS scheme redesigns may be subject to additional studies and upgrades to ensure system reliability.
- Projects interconnecting to feeders sourced by three-phase stepdown transformers will likely require upgrading to a new substation.
- Projects interconnecting to 34.5 kV lines will likely require direct transfer trip via fiber for protection.
- Projects using untested or otherwise unique generating, operating and protection technologies may require additional studies, upgrades and/or monitoring.
- Projects located in areas with no or limited radio coverage (for SCADA) or cellular coverage (for meter reading) may require fiber communications from the substation and possibly further upstream. This will trigger extensive make-ready costs for roadside distribution line rebuilds.
- Given the rapid expansion of DER system-wide and impacts to the transmission system, Versant Power will likely need to revisit and modify interconnection criteria occasionally to ensure predictable and stable operational performance of the EPS.

Versant shall determine any other special considerations that should be accounted for to ensure maximum system reliability and safety.

4.8 ISO-NE Transmission Cluster Studies

ISO New England (ISO-NE) is responsible for the reliability of the regional transmission network. Due to the dramatic increase in Distributed Energy Resources (DER) on the distribution network, ISO-NE requires additional review. Although some projects in Versant Power's service territory may be able to gain approval without the full Level 3 analysis, most are now subject to this additional review. All DER projects are subject to approval for interconnection by the ISO-NE Reliability Committee.

For 115 kV-sourced areas where the accumulation of DER has reached 20 MW, the Company must submit a Proposed Plan Application (PPA) for each project and a supporting Level 3 Cluster Study to ISO-NE. This is in addition to the distribution and local transmission impacts that the Company studies under the Chapter 324 interconnection process.

4.8.1 Level 3 Cluster Studies

Versant Power satisfies ISO-NE's additional study requirement by performing an analysis of DER projects in a cluster fashion. All DER projects in an area supplied by a 115 kV source that have had a Scoping Meeting for their project and subsequently submitted a signed SIS Agreement when a cluster study begins are invited to participate in the study. Once the cluster study is complete and accepted by ISO-NE, the next cluster study for that area will be initiated. Cluster study timelines may take months for final approval, are subject to ISO-NE study processes per FERC Order 2023, and are dependent on other transmission interconnections in the area of study.

Any DER project that chooses not to participate or does not supply the required information in time to participate in a cluster study must wait until the next round of cluster studies. Approval from ISO-NE indicating its agreement that the DER project has no adverse impacts to the regional transmission network is required before interconnection of the DER project.

4.8.2 Required Transmission Upgrades

If the results of a cluster study demonstrate that the DER projects in a given study area cause a transmission criteria violation requiring system upgrades, the responsible DER projects will share the cost of such upgrades. Versant Power will determine which DER project first triggered the violation based on the queue positions of the DER projects in the cluster study. All other DER projects in that area with a queue position after the DER project triggering the violation will be responsible for sharing costs of Contingent Upgrades based on the model in Chapter 324.

4.8.3 Required Information for Transmission Cluster Studies

Submission of PSS/E and PSCAD models for the specific equipment, including inverter model and firmware if applicable, may be required. For DER Facilities 5 MW or greater, a detailed dynamic model in the Siemens PSS/E format is required. The model must be from the list of NERC approved models and not a user-defined model.

5 DER Facility & Performance Requirements

This section describes the minimum design, operation and performance requirements for the DER Facility interconnecting with the Versant EPS.

5.1 Safety

Versant Power considers the safety of customers, personnel and the public to be paramount. All applicable electrical safety codes must be met when the DER Facility interconnects with the Versant EPS:

1. The DER Facility must be designed and operated in accordance with applicable electrical codes and electric industry standards in effect at the time and must be interconnected and operated in a manner that does not create a safety hazard to Versant Power or DER Owner personnel, customers and the public.
2. Versant Power will review the proposed design of the operating, protection, control and metering systems that are required for the interconnection of the DER Facility. The proposed design will be approved by Versant if it is found to be compliant with Versant's requirements.

5.2 General Requirements

The generator must operate and maintain the Generating Facility in accordance with Good Utility Practice and comply with all aspects of Versant Power's DER Interconnection Requirements and tariffs. After interconnection, the generator must continue to comply with all applicable laws and requirements.

The interconnection of the DER Facility must not compromise the reliability or restrict the operation of the Versant Power EPS. These reliability considerations include the following:

1. Power quality of the Versant EPS must not be deteriorated by the interconnection and operation of the DER Facility.
2. The DER Facility must be equipped to measure, record and report on performance related events to demonstrate compliance with the applicable sections of this document.
3. Any DER Facility found to violate requirements 1 and/or 2 above will be disconnected from the Versant EPS until the violation is rectified to Versant's satisfaction.

If Versant Power has reason to believe that the Generating Facility may cause problems on the EPS, Versant has the right to install monitoring equipment at a mutually agreed-upon location to determine the source of the problem(s). If the generator's equipment interferes with Versant's equipment, operations or other customers' equipment, the generator must take immediate corrective action to resolve the problem. Failure to take immediate action may result in Versant disconnecting the Generating Facility. The cost of monitoring equipment will be borne by Versant unless the problem or problems are demonstrated to be caused by the Generating Facility or if the test was performed at the request of the generator.

5.2.1 Design and Protection Changes

The DER Owner must provide Versant Power with reasonable advance notice of any proposed changes to be made to the DER Facility design, protection and control systems, relay settings, operating procedures, inverter model, firmware version or equipment that affect interconnection. Versant will determine if such proposed changes require reacceptance of the interconnection per the requirements of the Technical Interconnection Requirements. In the future, should Versant implement changes to the system to which the DER Facility is interconnected, the DER Owner will be responsible at its own expense for identifying and incorporating any necessary changes to its design, protection and control systems. These changes to the DER Facility are subject to review and approval by Versant Power.

5.2.2 Grandfathering

DER Facilities already connected to the Versant EPS are not exempt from the requirements of this document. Versant's Technical Interconnection Requirements are periodically revised to reflect changes in standard electrical practice and the EPS. Each DER Facility will be subject to review as a result of analyzing local EPS issues as well as during initial inspection and ongoing periodic tests and inspections. Versant may require reasonable modifications to the interconnection facilities as a result of these reviews, tests and inspections.

5.2.3 Disconnection

Temporary Disconnection:

A. **Emergency Conditions.** The Interconnection Agreement (IA) provides that Versant Power and the DER Facility will cooperate to minimize disruptions in service. The IA provides that Versant will have the right to immediately and temporarily disconnect the DER Facility, without prior notification, in emergencies and in cases of forced outages.
B. **Routine Maintenance, Construction and Repair.** The IA allows for the disconnection of the DER Facility from the Versant EPS when necessary for routine maintenance, construction and repairs.
C. **Forced Outages.** The IA provides that during any forced outage, Versant shall have the right to suspend interconnection service to effect immediate repairs on the Versant EPS. Versant will use reasonable efforts to provide the DER Facility prior notice. When circumstances do not permit such prior notice to the DER Facility, the IA provides that Versant may interrupt interconnection service and disconnect the DER Facility from the Versant EPS without such notice.
D. **Non-Emergency Adverse Operating Effects.** The IA provides that Versant may disconnect the DER Facility if the DER Facility is having an adverse operating effect on the Versant EPS or on Versant's other customers.
E. **Modifications of the DER Facility.** The IA provides that Versant may immediately suspend interconnection service in cases where the DER Facility has implemented modifications to the DER Facility without prior written authorization from Versant.
F. **Non-Compliance.** If a DER Facility interconnects to Versant Power's EPS without having received approval for the interconnection through the process described in MPUC Chapter 324, Versant Power may require disconnection of the

DER Facility and the costs of the inspection by Versant shall be borne by the DER Owner.

G. **Reconnection.** Any curtailment, reduction or disconnection shall continue only for as long as is reasonably necessary. The DER Provider and Versant will cooperate to restore the DER Facility and the EPS to their normal operating states as soon as reasonably practicable following the cessation or remedy of the event or condition that led to the temporary disconnection.

Permanent Disconnection:

- The IA provides that the DER Owner may permanently disconnect at any time with 30 calendar days written notice to Versant Power.
- The IA provides that Versant may permanently disconnect the DER Facility upon termination of the IA.
- The IA provides that Versant Power may permanently disconnect the DER Facility if the DER Owner is unable, after notice, to correct negative impacts on Versant's other customers or the EPS caused by the DER Facility.

5.2.4 No Adverse Effects to the EPS

Versant Power shall notify the generator if there is evidence that the operation of the Generating Facility could cause disruption or deterioration of service to other customers served from the same EPS or if operation of the Generating Facility could cause damage to the EPS or affected systems. The deterioration of service could be, but is not limited to causes at the Generating Facility:

- Harmonic injection in excess of IEEE Standards 1547 & 519
- Voltage flicker in excess of IEEE Standards 1547 & 1453
- Rapid voltage changes in excess of IEEE Standard 1547 caused by large step changes
- Other causes

Voltage changes, including the impact of any anticipated intermittent output values, will be evaluated using Table 25 in IEEE 1547. The immediate voltage change due to the energizing or tripping of the entire facility must be less than 3% on nominal voltages 46 kV and above; and less than 5% on nominal voltages less than 46 kV.

5.2.5 Notification & Correction of Emergency or Hazardous Conditions

Each party will notify the other in a timely manner of any emergency or hazardous condition or occurrence with its equipment or facilities that could affect safe operation of the other party's equipment or facilities. Each party shall use reasonable efforts to provide the other party with advance notice of such conditions. The generator shall take immediate action to correct interference with Versant's EPS.

5.2.6 EPS Disturbances

Versant Power will operate the EPS in such a manner as to not unreasonably interfere with the operation of the Generating Facility. The Generating Facility will protect itself from disturbances propagating through the EPS, and such disturbances shall not constitute unreasonable interference. Examples of such disturbances could be single-phasing events, voltage sags from faults on the EPS and outages on the EPS.

Islanding on any part of the EPS is not allowed as it may result in unsafe and unreliable conditions on the EPS. The intent of the interconnection protection requirements is to prevent an unsafe and unreliable condition.

5.2.7 Safe Operations and Maintenance

Each party shall be responsible for the maintenance, repair and condition of the lines and appurtenances on its side of the PCC. Versant Power and the generator shall each provide equipment on its respective side of the PCC that adequately protects the Versant EPS, personnel and other persons from damage and injury.

5.2.8 Reference Point of Applicability (RPA)

The RPA or measurement location is the point of measurement for implementing protection and control functions required for interconnection. The characteristics of the local Versant EPS and the DER Facility will determine the Reference Point of Applicability. Typically, this is at the Point of Common Coupling (PCC) but in some cases may be at the Point of Interconnection (POI).

The DER Owner will identify, with Versant Power's agreement, the POI and the PCC on the project single-line diagram (SLD) provided as part of the DER interconnection process.

DER sites with no path for zero sequence continuity between the PCC and POI must be able to detect area power system faults and open phase conditions at an appropriate agreed-upon location as per IEEE 1547-2018 Sections:

- 4.2 Reference Points of Applicability
- 6.2 Area EPS Faults and Open Phase Conditions
- 6.4 Voltage

5.2.9 DER Isolation Device

The DER Facility must be able to disconnect from the Versant Power EPS using at least one electrical isolation device. Refer to Section 7.1 for more design details and requirements for the isolation device.

The DER Owner must coordinate all switching, tagging and lockout procedures with Versant Power. This is typically accomplished through Versant's System Operations.

5.3 Insurance Requirements

5.3.1 General Liability — Projects Meeting Versant's Standard Interconnection Requirements

Based on MPUC Chapter 324, the DER Owner may be required to provide general liability insurance coverage as part of the Interconnection Agreement. No insurance is required for non-inverter-based DER Facilities less than or equal to 50 kW or for inverter-based DER Facilities less than or equal to 1 MW. Requirements for other sizes are shown in Table 5-1 below.

5.3.2 Effect

Any inability of Versant Power to require the DER Owner to provide general liability insurance coverage for operation of the new DER Facility is not a waiver of any rights Versant may have to pursue remedies at law against the DER Owner to recover damages.

Table 5-1: Required Insurance by DER Size & Type

Generation Capacity	Non-Inverter Based	Inverter Based
> 5 MW	$3,000,000	$2,000,000
> 2 MW and ≤ 5 MW	$2,000,000	$1,000,000
> 500 kW and ≤ 2 MW	$1,000,000	-
> 50 kW and ≤ 500 kW	$500,000	-

5.4 Access

If necessary for the purposes of the DER Technical Interconnection Requirements, the generator shall allow Versant access to Company equipment and facilities located on the Generating Facility's premises. To the extent that the generator does not own the property on which Versant is required to locate its equipment or facilities to serve the Generating Facility, the generator shall secure and provide to Versant the necessary rights for access to such equipment or facilities, including easements.

Versant shall have both truck and utility worker access to the disconnect switch of the Generating Facility and Versant POI equipment at all times.

5.5 Representative Contact Information

Each party shall provide and update as necessary the telephone number and other applicable contact information that can be used at all times to allow the other party to report an emergency and coordinate operations.

5.6 General Design Requirements

1. Any generator desiring to interconnect with Versant Power's EPS or to modify an existing Interconnection must meet specifications as set forth in the following standards and other requirements specified by Versant where applicable:

- Current version of IEEE 1547 Standard for Interconnection and Interoperability of DER with Associated EPS Interfaces
- ISO-NE Default IEEE 1547-2018 Setting Requirements
- IEEE Standard 929 Recommended Practice for Utility Interface of PV Systems
- UL (Underwriters Laboratories) Standard 1741-SB
- Other applicable codes and standards as listed in Appendix C

2. The specifications and requirements listed herein are intended to mitigate possible adverse impacts caused by the Generating Facility to Versant Power's equipment and to protect the safety of Versant's personnel and other customers of Versant. They are not intended to address protection of the Generating Facility itself or its internal load. It is the responsibility of the generator to comply with the requirements of all appropriate standards, codes, statutes and authorities to protect itself and its loads.
3. If requested by the generator, Versant Power will provide system protection information for the line terminal(s) directly related to the interconnection (POI). This protection information is provided exclusively for use by the generator to evaluate protection of its Generating Facility during parallel operation.
4. The generator shall not operate a Generating Facility that superimposes a voltage or current upon Versant's EPS that interferes with Company operations, service to other customers or communication facilities. If such interference occurs, the generator must take corrective action within 8 hours of being notified by Versant Power or first learning of the interference. If the interference cannot be corrected within 8 hours, or sooner for some circumstances, Versant may require the generator to cease parallel operation with the EPS. If the generator does not correct the interference or cease parallel operation when directed to do so by Versant, we may, without liability, disconnect the Generating Facility from Versant's system.
5. Automatic reclosing of Versant Power's circuits will usually occur following tripping operations and the reclosing operation should not be limited by the Generating Facility's interconnection. The generator must take reclosing into consideration when designing the Generating Facility to avoid equipment damage that may result from Versant's circuit reclosing. Reclose-blocking relay schemes, synch check and/or directional overcurrent protection may be required to be added to Versant breakers and/or line reclosers at the generator's expense.
6. The Generating Facility must disconnect all DERs in the event there is a configuration change to the EPS not studied or approved in the DER interconnection process.
7. All DERs must be disconnected and remain disconnected during planned and unplanned system events or as directed by Versant Power System Operations.
8. All switching & tagging between the Versant Power EPS and the Generating Facility involving the manual operation of an airbreak switch or other devices will require prior disconnection of any interconnected DER from the Versant EPS.
9. Generating Facility connections on the load side of an area network system (i.e., 208Y/120-volt secondary network system) shall meet IEEE 1547 requirements.
10. When connecting to a distribution circuit, a maximum output of the aggregate of all generation interconnected to the distribution low voltage side of the

substation transformer may be imposed if it is determined that there are transient stability limitations to generating units located in the general electrical vicinity.

11. For interconnection of a proposed single-phase Generating Facility where the primary distribution system is three-phase, four-wire, the Generating Facility will be connected line-to-neutral. For interconnection of a proposed single-phase Generating Facility where the primary distribution system is three-phase, three-wire, the Generating Facility will be connected line-to-line.
12. For the interconnection of a proposed Generating Facility to any distribution secondary spot network, the Generating Facility must utilize a protective scheme that will ensure its current flow will not affect the network protective devices, including reverse power flow relays or a comparable function. Synchronous Generating Facilities cannot be interconnected to a distribution secondary spot network, either for momentary or continuous operation.
13. When measured at the secondary side (low voltage) of a shared distribution transformer, the short circuit contribution of the Generating Facility must be less than or equal to 2.5% of the interrupting rating of Versant Power's service equipment.
14. When the proposed interconnection may result in reverse power flow through Versant's load tap changing transformer(s) or line voltage regulator(s), Versant may make control modifications to these devices to mitigate the effects. These modifications would be at the generator's expense. Otherwise, the Generating Facility may be required to limit its output so reverse power flow cannot occur or provide reverse power relaying that trips the Generating Facility.
15. Disconnect Switch. Generators 250 kW and greater in aggregate shall provide an external disconnect switch at the Point of Common Coupling (PCC) that can be opened for isolation. The switch shall be in a location easily accessible to Versant Power's personnel at all times. The switch shall be gang-operated, have a visible break when open, be rated to interrupt the maximum generator output and be capable of being locked open by Versant's personnel. Versant shall have the right to open and lock the disconnect switch as required. The switch shall have the same requirements as the isolation device in Section 7.1.
16. Generators 500 kW and larger will require a Versant POI recloser with SCADA for redundant protection in addition to the generator's primary protective device. Generators 250 kW to 499 kW will require a customer-owned three-phase recloser for primary protection. These kW thresholds are subject to engineering discretion based on other system considerations. If interconnecting to a circuit with an ALT Scheme (Automatic Load Transfer), generators 100 kW and larger may require a utility POI recloser with SCADA for redundant primary protection and disconnecting the Generator Facility during ALT Scheme operation.
17. If applicable, the Versant POI recloser must be installed and operating in order for a DER Facility to be energized and exporting power.
18. In rare circumstances, Versant may require that its equipment be located on the customer side of the PCC. In this case, the DG Owner must provide the necessary space for Versant to install such equipment and Versant must approve this facilitation. A 120V AC power service is to be available at this location.

5.7 Metering, Monitoring, and Communication

5.7.1 Metering Equipment

Metering of the output from the Generating Facility shall be by meters and metering devices provided, installed, owned and maintained by Versant Power. Metering requirements will vary with the type and intent of the DER Facility. Versant will assess a one-time charge for the equipment and installation, plus ongoing third-party data transfer fees for communicating with the meter. Bidirectional energy flow must be metered for any Generator Facility connected to Versant's EPS. Versant reserves the right to select the appropriate communication method for communicating with the meter. Additional meters may be necessary for Versant to record gross energy output as required by the MPUC Chapter 313 customer Net Energy Billing rules for those Generating Facilities that participate in the Net Energy Billing program.

All meters used to determine the billing hereunder shall be sealed, and the seals shall be broken only by Versant upon occasions when the meters are to be inspected, tested or adjusted. The Generator shall provide access for a representative of Versant to the billing meter at all reasonable times for the purpose of meter reading. Versant shall make periodic tests of the metering equipment. Upon request of the Generator, Versant will make additional tests. However, if the Generator requests a test to be made within 12 months of a previous test, such test shall be at the expense of the Generator if the meter proves to be accurate within 4%.

In the event errors greater than 4% are discovered, the cost of the test shall be at the expense of Versant Power. Retroactive billing adjustments for errors found as a result of any test shall be made for a period equal to one-half of the time elapsed since the previous tests, but not to exceed six months.

Each party shall give reasonable notice to the other party of the time when any inspection or test shall take place, and that party may have representatives present at the test or inspection. The Generator shall be notified before all metering tests and shall have the right to observe the test and perform its own test. If the meter is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Versant's expense, to provide accurate metering.

5.7.2 Communication

All communication infrastructure between the Versant EPS and the DER Facility for metering and SCADA will be reviewed and approved by Versant on a case-by-case basis. The communication infrastructure will support fast, secure and reliable communication to meet the technical requirements for the protection, control and monitoring requirements of the DER Facility.

In general, Versant Power uses the following methods for communicating with Versant POI equipment based on the following functions:

- Revenue metering: cellular wireless telecommunications is preferred; fiber if cellular is not available

- SCADA real time monitoring and control: two-way radio preferred; fiber if radio or cellular are not available
- Protection: fiber only (typically for DTT if required)
- Web-based technologies are not accepted

ISO-NE has additional requirements for DERs greater than 5 MW in aggregate. A fiber path for protection functions and communication may also be required for direct interconnections to subtransmission and DER Facilities interconnecting to distribution side lines tapped to subtransmission.

Versant may require a different method of communication should the planned or installed method become ineffective. Upgrading the communication method as necessary will be at the expense of the DER Owner as well as any required ongoing costs or fees.

5.7.3 Supervisory Control and Data Acquisition

Versant Power employs a Supervisory Control and Data Acquisition (SCADA) system to control and monitor the status of its power system. The SCADA system provides real-time status of the power system and its components by gathering information at each installation via a Remote Terminal Unit (RTU) or equivalent device interconnected to a Master Control.

Generation Facilities interconnecting in the BHD with 500 kW or more of net generation must have SCADA to provide the necessary information and control for monitoring the stability and maintaining the integrity of the Versant EPS. Additional monitoring may be required for ISO-NE as described in ISO-NE's Operating Procedure No. 18 (OP18).

Generators interconnecting in the MPD and under the jurisdiction of the Northern Maine Independent System Administrator (NMISA) will require SCADA if net generation is larger than 500 kW.

The method used for SCADA communications will be radio or cellular if feasible. Otherwise, fiber may be required.

The Generator's RTU design and procurement must be reviewed with Versant to ensure compatibility with Versant's SCADA system. If a Versant recloser is installed at the POI for redundant protection, there will be no RTU interface at the Generator's primary high voltage (HV) protective device.

5.7.4 Additional Monitoring and Communication Requirements

Generation facilities with 250 kW or more of net generation or Generators on a Tariff Rate require communications to the meter. As the amount of distributed generation on Versant's EPS grows significantly, the MPUC, ISO New England, Versant or other jurisdictions may require additional monitoring and communication.

6 DER PROTECTION & CONTROL REQUIREMENTS

This section describes the technical requirements for the protection schemes to be installed at the DER Facility, power flow control aspects and interrelated operations with Versant's distribution system.

6.1 TYPICAL PROTECTION CONFIGURATIONS

Typical interconnection configurations based on DER technology, export capacity and transformer type are included in Appendix B. They illustrate Versant's general protection requirements.

The required protection and isolation device types vary according to the size of the DER Facility. Table 6-1 below lists the DER Facility size thresholds and associated high voltage primary protection for both Versant and the DER Facility, the DER disconnect type and when SCADA is required.

Table 6-1: Primary Protection & Isolation Device Requirements by DER Size

DER Facility Capacity[1]	Versant POI HV Protection & Isolation	DER PCC HV Primary Protection	DER Disconnect	SCADA Required[4]	Refer to Appendix B For SLD
≥500 kW	Utility Recloser & SB Disconnects	Recloser	Accessible Lockable HV GOAB Disconnect Switch	Yes	Type 4-1 4-2 or 4-3
250 kW to 499 kW[2]	SB Disconnects, Fused Cutouts (or Recloser[2])	Recloser	Accessible Lockable HV GOAB Disconnect Switch	See Note 2 Below	Type 3-1
25 kW to 249 kW[3]	SB Disconnects or Fused Cutouts	Fused Cutouts for Stand Alone DER – N/A for Behind-the-Meter	Secondary Fused Disconnect Switch or Breaker per NEC[5]	No	Type 2-1
<25 kW	SB Disconnects or Fused Cutout(s)[6]	N/A	Secondary Disconnect or Breaker per NEC	No	Type 1-1, 1-2 1-3 or 1-4

1. **kW thresholds are not explicit and are subject to engineering discretion based on POI stiffness factor and/or other EPS considerations.**
2. **If interconnecting to an ALT scheme circuit, a utility recloser & SCADA is required to prevent export during ALT operation. An ALT Study may determine no integration is required. Refer to Section 6-23.**
3. **For all interconnections without a DER PCC recloser, Versant will install fused cutouts for isolating generator lead issues from the EPS. The fused cutouts will serve as a utility disconnect.**
4. **Versant SCADA equipment will be installed in the utility POI recloser. There are no connections to or utility equipment within the DER Facility recloser.**
5. **A fused disconnect for secondary protection may be acceptable if not connected to a shared secondary other customers.**

6. **To be installed at Versant's discretion or in compliance with Versant Distribution Construction Standards.**

6.2 VOLTAGE REGULATION

The operation of a DER Facility shall not cause Versant's EPS voltage to exceed ANSI C84.1 limits. This generally refers to a standard voltage of 120V plus or minus 5%. Meeting this requirement may require modifications to the EPS at the expense of the generator.

The DER Facility must not regulate voltage at the PCC unless otherwise previously required and approved by Versant Power.

The startup and shutdown of the DER Facility must be done in a manner that allows the Versant substation tap changer and line regulators to adjust voltage to ensure they are within the appropriate limits.

To meet the voltage regulation requirements, the DER Facility must, at a minimum, implement the following control methods:

1. **Induction Generation**
    a. Induction generation rated in aggregate ≥150 kW may be required to provide reactive power compensation to maintain generation output power factors of 95% leading or better, at full rated power output (a leading power factor for generation means that reactive power is absorbed by the DER Facility from the Versant EPS).
    b. If the selected reactive power compensation rating matches or exceeds the limit for self-excitation of the generator, provisions must exist in the design and operation of the DER Facility to disconnect the compensation equipment when a fault occurs on the Versant EPS.
2. **Synchronous Generation:**
    a. Synchronous generation rated in aggregate >30 kW must be able to operate continuously at any power factor between 95% lagging and 95% leading at full-rated power output. Versant will determine the actual set-point between these limits on a case-by-case basis.
    b. DER operation in power factor control mode must meet the following requirements:
        i. The maximum DER response time to the deviation of power factor to restore the set power factor must be 10 seconds or less.
        ii. Control schemes for the excitation control system of the generator that reduce excitation current must be made whenever an overvoltage exceeding the voltage regulation criteria is detected at either the generator terminal or the PCC.
        iii. In some cases, DER operation in voltage control mode may be required to be implemented in lieu of power factor control mode. Versant will determine the need for this requirement on a case-by-case basis. If determined necessary, voltage control mode must be able to meet the following requirements:

1. Maintaining voltage at the PCC within the voltage regulation criteria year-round.
2. Having a time-delay function with the provision to adjust the delay between 0 and 180 seconds. Versant will determine the actual time delay required on a case-by-case basis.

3. **Inverter-based Generation:**
   a. Constant power factor mode with unity power factor setting must be the default mode of the installed DER unless otherwise previously specified by Versant.
   b. The DER Facility must not inject DC current greater than 0.5% of the full rated output current at the DER inverter AC output terminals.
4. When determined necessary by Versant, the DER Facility must either operate the DER within a larger range of power factor control or implement more active voltage regulation modes such as Volt/Var control, Volt/Watt control, adjustable constant reactive power, or other modes as specified by IEEE 1547 for grid support inverters. Versant will determine the details of this requirement via Volt/Var Operational (Long Term Dynamics) Study on a case-by-case basis. Generally, DER facilities 500 kW and greater are required to operate in Volt/Var mode.

6.3 Voltage Flicker & Harmonics

The combination of change in voltage magnitude and the frequency of voltage changes can produce an objectionable voltage fluctuation on Versant's EPS. Harmonics can cause transformer and motor thermal overheating, communication system interference, electronic device failure and resonant overvoltages. DER Facilities shall comply with the flicker and harmonic limits per IEEE 1547 and IEEE 1453.

1. Rapid voltage changes for frequent events: To limit voltage flicker, DER connected to medium voltage shall not cause a step change in voltage exceeding 2% of nominal and exceeding 2% per second over one second as a result of sudden changes due to frequent energization of transformers, capacitors or from abrupt output variations. For DER connected to low voltage, the DER shall not cause a step change in voltage exceeding 5% of nominal or 5% per second over one second as a result of sudden changes due to abrupt output variations or other reasons.
2. Rapid voltage changes for infrequent events: The immediate voltage change due to the infrequent energizing or tripping of the entire DER Facility must be less than 3% on nominal voltages 46 kV and above and less than 5% on nominal voltages less than 46 kV.
3. Entering service. DER shall increase output of active power linearly or in a step-wise linear ramp, with an average rate-of-change not exceeding the DER nameplate active power rating divided by the enter service period. The duration of the enter service period shall be adjustable with a default time of 300 seconds. The maximum active power increase of any single step during the enter service period shall be less than 20% of the DER nameplate active power rating (i.e. a linear increase in active & reactive power over 5 minutes, where a step increase shall not exceed a 20% increase). Slower ramp rates are acceptable. Refer to Appendix D Section 1.5 for more details.

4. Normal operation: The generator shall be loaded and unloaded gradually to allow adequate time for regulating devices on Versant's EPS to respond and avoid excessive voltage fluctuations.
5. Generators requiring reactive support or providing voltage regulation shall limit the magnitude of reactive power flow changes to slow ramp transitions to avoid voltage flicker.
6. Voltage changes, including the impact of any anticipated intermittent output values, will be evaluated using Table 25 in IEEE 1547.
7. Tap changing: To limit excessive tap changes for Versant's voltage regulating equipment, a step change in DER output from 100% to 25% shall not cause a tap change of more than one position.

6.4 Voltage & Current Unbalance

1. A generator shall be capable of operating under existing unbalance conditions and shall not cause deterioration of existing unbalanced voltage and current conditions at the PCC and in the Versant EPS.
2. Voltage unbalance on Versant feeders may reach 5% under normal operating conditions.
3. A generator and its interconnection transformer design shall take into consideration the unbalanced current it may supply to the unbalanced load on the feeder.
4. A generator shall protect itself from highly unbalanced voltages and currents especially when connected to feeders where single-phase reclosing is used.
5. A single-phase generator shall not significantly impact the unbalance of the nearest three-phase distribution system.
6. A single-phase generator shall not cause an unbalance of greater than 2%. If multiple single-phase generators are installed, they shall be connected so that an equal amount of generation is applied to each phase of the distribution line, and this balance shall be maintained if one or more of the generating units is offline.

6.5 Power Factor

The DER Facility shall be capable of operating at unity power factor unless the System Impact Study specifies a fixed power factor or automatic voltage regulation mode to maintain the Versant EPS voltage at an acceptable level. If a DER Facility is required to operate outside of unity power factor, the acceptable range shall be limited to 95% leading or lagging power factor. If warranted by local distribution system conditions, this range may be narrower or wider and will be specified by Versant. Versant may also request that the DER Facility operate in a revised power factor range during a system emergency.

If during normal operation a DER Facility is not operating within the approved power factor mode and/or range, Versant may disconnect the DER Facility per Section 5.2.3.

6.6 Active & Reactive Power Limits

The DER Facility must meet the following active and reactive power requirements:

1. Power delivery to the Versant EPS through the DER Facility PCC must not exceed the Maximum Allowable Export Capability permitted by Versant upon completion of the SIS.
2. Reactive power must be controlled to comply with the voltage and power factor requirements described in Section 6.5, as well as the requirements & settings described in the results of Volt/VAR Operational Studies.
3. DER Facilities applying for a specific real power rating (kW) will not be allowed to exceed this rating for apparent power (kVA). The maximum export kW rating applied for will be equal to the maximum export kVA rating allowed for the DER Facility. No kVA overhead is allowed.

6.7 Export Control

If a DER Facility uses an export control system described in this section to limit the export of electrical power across the PCC, then the export capacity shall be limited to the amount the facility is capable of exporting (not including any inadvertent export). To prevent impacts on EPS safety and reliability, any inadvertent export from a DER Facility must comply with the limits identified in this section. The export capacity specified by the DER Facility application will subsequently be included as a limitation in the Interconnection Agreement.

An application proposing to use a configuration or operating mode to limit the export of electrical power across the PCC shall include proposed control and/or protection settings.

Table 6-2: Acceptable Export Control Methods

Acceptable Export Control Methods		
	Non-Exporting DER Facility	Limited-Export DER Facility
Reverse Power Protection (32R)	X	
Minimum Power Protection (32F)	X	
Relative DER Facility Rating	X	
Directional Power Protection (32)		X
Configured Power Rating		X
Certified Power Control System	X	X
Agreed-Upon Method	X	X

A. Export Control Methods for Non-Exporting DER Facilities:

1. Reverse Power Protection (32R): To limit export of power across the PCC, a reverse power protective function is implemented using a utility grade protection relay. The default setting shall be 0.1% (export) of the service transformer's nominal base nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.

2. Minimum Power Protection (32F): To limit the export of power across the PCC, a minimum import protective function is implemented using a utility grade protection relay. The default setting shall be 5% (import) of the DER Facility's total nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.

3. Relative DER Facility Rating: The DER Facility's nameplate rating is so small in comparison to its host facility's minimum load that the use of additional protection functions is not required to ensure that power will not be exported to the Versant EPS. This option requires the DER Facility's nameplate rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available to interconnections to area networks or spot networks.

B. Export Control Methods for Limited-Export DER Facilities:

1. Directional Power Protection (32): To limit export of power across the PCC, a directional power protection function is implemented using a utility grade protection relay. The default setting shall be the export capacity value, with a maximum 2.0 second time delay to limit inadvertent export.

2. Configured Power Rating: A reduced output power rating utilizing the power rating configuration setting may be used to ensure the DER Facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER Facility communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

C. Export Control Methods for Non-Exporting or Limited-Export DER Facilities:

1. Certified Power Control System (PCS): A DER Facility may use a certified PCS to limit export. A DER Facility utilizing this option must use a PCS and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit inadvertent export. NRTL testing to the UL PCS Certification Requirement Decision (CRD) shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks. CRD documentation shall be submitted with the application.

2. Agreed-Upon Methods: A DER Facility may be designed with other control systems and/or protection functions to limit export and inadvertent export if mutual agreement is reached with Versant Power. The limits may be based

on technical limitations of the interconnection customer's equipment or the EPS equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified PCS, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by Versant Power.

3. Note that export controls do not act in time to prevent transient behaviors of DERs. Export controls typically cannot act fast enough to prevent contributions to fault current and short circuits. Thus, Versant will evaluate the fault current and short circuit contributions of the entire connected kVA of the export-controlled project and may require upgrades to mitigate adverse impacts.

6.8 Non-Export Power

Generating Facilities that do not intend to export power to Versant's EPS but which may export power incidentally must include, if applicable, a reverse power relay with a setting of 10% (export) of the aggregate generation, with a maximum 2.0 second time delay unless an underpower protection function is utilized to ensure a minimum import of power at the PCC. This would not apply to equipment that includes a certified non-islanding function. Other methods that might mitigate for this issue include transfer trip, protective functions to detect phase and ground faults on Versant's EPS, reclose blocking of EPS equipment, or other acceptable means.

6.9 Transfer Tripping

If a direct transfer trip (DTT) system is required by either the generator or by Versant, the DTT equipment shall be generally accepted for use by Versant and shall, at the option of Versant, use dual channels. Fiber is the only accepted method of communication for transfer tripping to ensure low latency, high reliability and high quality. The following conditions apply:

1. The generator shall cease to energize the Versant EPS with no intentional time delay and isolate all generation and HV ground sources upon receipt of a DTT signal.
2. The maximum DTT time will be specified by Versant, but electrical isolation must be fully complete in less than 1.5 seconds (a 0.5 second margin will ensure DER is fully disconnected to ensure a 2.0 second automatic reclosing interval).
3. The generator will remain disconnected from Versant's EPS if the DTT channel is unavailable.
4. The DTT system shall be failsafe.
5. Upon loss of the DTT communication channel, the generator and HV ground sources shall disconnect within 5 seconds of the channel failing. A controlled shutdown may be allowed but must be approved by Versant in advance.
6. The generator shall remain disconnected until the DTT channel is repaired and Versant System Operations has been advised that all Generator Facility interconnection protections have been restored to service.

7. DTT equipment must be maintained to ensure it remains fully functional. This may require coordinated efforts between the DER Facility and Versant for the purpose of scheduled maintenance and testing.

DTT may be required for any of the following scenarios:

1. From the substation to the PCC for all generators with aggregate capacity 500 kW or larger
2. From the feeder breaker and/or upstream midline recloser(s) for any of the following conditions:
   a. When the aggregate Generator Facility capacity is greater than 50% of the minimum feeder load or 50% of the minimum load at the upstream midline recloser
   b. When the aggregate generation, comprising existing generation, other proposed DER facilities, at the feeder or distribution substation including the Generator Facility, is greater than 50% of the minimum feeder load or minimum load downstream of an upline recloser(s)
   c. If the existing reclosing interval of the feeder breaker and/or upstream recloser(s) is less than 1.0 second
3. For DER indicating a risk of islanding
4. For DER interconnecting to a feeder with an ALT scheme or a substation sourced by a transmission line containing an ALT scheme
5. For DER interconnecting to a substation or feeder with UFLS protection
6. For DER interconnecting to subtransmission lines

Where DTT is necessary for Generator Facilities requiring a Versant-owned redundant recloser, either the Versant or customer recloser will be the terminal point of communications and device to be tripped at Versant's discretion.

Implementation of DTT may not be required for the original request for interconnection application but may be requested by Versant at any time at the generator's cost.

6.10 Communications Channels

Versant Power will procure any necessary communication channels between the Generating Facility and Versant's substations and will provide protection from transients and overvoltages at all ends of these communication channels. The generator is responsible for bearing these installation costs as well as Versant's ongoing costs to lease, operate and maintain these communication channels. Examples include, but are not limited to, connection to a line using high-speed protection, transfer tripping, (i.e., facilities located in areas with low fault currents, or backup for Generating Facility breaker failure), meter reading and SCADA functions. Methods of communication include radio (for SCADA), cellular (for SCADA & metering) and fiber (protection, SCADA & metering).

6.11 Point of Interconnection Interrupting Device

An interconnection interrupting device such as a circuit breaker or recloser shall be installed to isolate the Generating Facility from Versant's EPS. If there is more than one interrupting device, this requirement applies to each one individually. The interconnection interrupting device must be capable of interrupting the current produced when the Generating Facility is connected out of phase.

6.12 Interconnection Transformer

An interconnection transformer may be located between the PCC and the DER Facility and is used to step up or step down the DER's output voltage for interconnection with the Versant EPS. The transformer selection affects voltage regulation, fault current contribution, and harmonic current flow on the Versant EPS. The DER interconnection transformer must not cause voltage disturbances or disrupt coordination of Versant's distribution system ground fault protection. Versant may require connection to its EPS through a dedicated transformer and may specify the winding connections. The System Impact Study will review the DER-proposed transformer connection and grounding configuration and will propose changes to the winding configuration, ratings, and/or specifications as required. Delta connections on Versant's side of the interconnection transformer are typically not allowed.

In the event that the transformer winding connection is grounded-wye/grounded-wye, Versant may specify whether a synchronous generator stator is to be grounded or not grounded. The generator shall be responsible for procuring equipment with a level of insulation and fault withstand capability compatible with the specified grounding method.

Replacement, at the customer's expense, of a Versant transformer to increase the power rating or insulation levels, change winding connections, or change lightning arrester ratings may be required due to the addition of customer generation. In addition to requiring an isolation transformer, Versant may require current limiting reactors, either shunt connected or in series to limit short circuit current levels.

The configuration and applicable NEB rule of the DER Facility will affect the following additional interconnection transformer requirements:

1. A <u>standalone</u> generating facility will require a dedicated DER Facility-owned interconnection GSU transformer regardless of NEB rule it is operating within.
2. Versant Power allows the use of the existing utility service transformer for generation interconnection but only for a <u>non-standalone</u> generating facility operating under NEB kWh credit rules. Any upgrade required to the utility transformer will be at the facility's expense.
3. In general, Versant Power does not allow the use of the utility service transformer for generating facilities operating under the NEB Tariff rate rules. However, a <u>non-standalone</u> generating facility less than 250 kW export capacity operating under NEB Tariff Rate rules may be allowed to interconnect to the utility service transformer if the generating facility owner is the only load customer served by the utility transformer and the existing utility service transformer has adequate capacity for the generating facility. Versant Power does not replace utility service transformers to accommodate NEB Tariff Rate facilities.

6.13 Interconnection Transformer Inrush

Generator Step-up (GSU) transformer inrush current can be very high, as much as 25 times the rated full load current. Therefore, some projects with particularly large GSU transformers, in relation to the distribution capacity available at the PCC, may have protection coordination issues. For example, the DER Facility recloser, or any upstream device, is not allowed to trip due to GSU transformer inrush upon energizing the project.

As part of the Protection Evaluation within an SIS, Versant will evaluate the impact to coordination of upstream protection devices based on IEEE Standard 242-2001. The study results will determine if inrush may need to be mitigated if coordination cannot be obtained.

If inrush fails to coordinate with the Generator Facility primary HV protection, the Protection Coordination Study includes a Magnetizing Inrush Assessment to confirm if the inrush as calculated per the IEEE 242-2001 Standard may coordinate with the Versant POI recloser. If the assessment fails, the generator will be notified that inrush mitigation is required. Versant will provide the maximum inrush value required to adequately coordinate the generator and the project path reclosers so that the generator may determine solutions to mitigate inrush.

There are several mitigation options that may be available:

1. Obtaining the GSU transformer design data from the manufacturer to allow for a more detailed inrush assessment. Inrush current may be less than the IEEE 242-2001 standard values per the transformer design specifics.
2. If multiple GSU transformers are included in the Generating Facility design, transformer energization may be sequenced.
3. Several devices are on the market to provide inrush mitigation. Versant will evaluate a device proposed by the generator. Versant does not approve or guarantee performance of any device as a result of accepting its use and installation.

It is the generator’s responsibility to select an inrush mitigation technique (if required) for Versant to evaluate during the protection study.

Versant will confirm if the selected inrush mitigation technique is acceptable via the inrush assessment and will confirm mitigation is achieved during the witness tests.

6.14 Reactive Compensation

In instances where the generator would need to absorb reactive power in order to maintain voltage within limits, a compensating source of reactive power will be required to be purchased by the generator for installation on Versant’s EPS at the location Versant has determined to be appropriate. A Volt/Var Operational study may be necessary to determine impacts of reactive power flows on Versant’s tap changing and reactive capacity equipment.

The reactive power requirement for induction generators may be supplied from Versant's EPS. For aggregate generation of up to and including 100 kW, there will be no charge to the generator. For aggregate generation greater than 100 kW, the generator may be charged a one-time charge to cover the cost of supplying the capacitive reactive supply for the generator plus any ongoing O&M charge for that equipment. The capacitor charge will include the complete installation cost of capacitors as required by the Generating Facility.

Versant may require the Generator Owner to reimburse the utility's cost to install switched capacitors or other technologies such as STATCOMs or DVARs to limit the adverse effects of reactive power support from Versant's EPS related to operation of the Generating Facility.

6.15 Effective Grounding

Versant's distribution circuit will remain effectively grounded in any generator configuration to limit unfaulted phase voltages to less than or equal to 138% of nominal phase voltage during unbalanced fault conditions. DER Facilities shall meet the effective grounding criteria calculations of $X0/X1 < 3$ and $0 < R0/X1 < 1$. Versant may require the installation and provide the specifications of a grounding bank transformer (GBT) and any other associated changes if the proposed design does not meet the effective grounding criteria and/or the GFOV (Ground Fault Over-Voltage) limits as determined from a TDS.

6.16 Fault Current Contributions

The generator's fault contribution shall not cause the fault duty of any Versant protective device to exceed 90% of its interrupting rating. Should that be determined by study, device upgrades will be required. Changes to Versant's protection and fuse savings schemes or equipment will be at the generator's expense.

6.17 Phase & Ground Fault Protection

Phase and ground current protection are required to (1) clear the Generator Facility contributions from the Generator Facility into faults on the interconnected feeder and (2) isolate the Generator Facility and collector system from Versant's EPS when faults occur within the Generator Facility.

During the engineering design stage, Versant Power will provide the Generator Facility the maximum phase and ground fault currents and Thevenin equivalent impedances at the PCC with existing DER facilities connected. Versant will also provide the maximum impedance faults that the Generator Facility shall be capable of detecting.

Consideration must be given to the possibility of Generator Facility ground source currents being present when the generation is out-of-service and the primary HV voltage ground source is not disconnected. This will depend on the primary HV grounding configuration. The ground source must be isolated upon detection of internal Generator Facility faults or external distribution system faults.

Generators 500 kW and larger will require a utility-owned POI recloser with SCADA for redundant protection in addition to the generator's primary HV protective device.

Generators 250 kW to 499 kW will require a customer-owned three-phase recloser for primary HV protection. These kW thresholds are subject to engineering discretion based on other system considerations. If interconnecting to a circuit with an ALT Scheme (Automatic Load Transfer), generators 100 kW and larger will require a utility POI recloser with SCADA for redundant primary HV protection and disabling the generator interconnection during ALT Scheme operation.

6.18 Voltage & Frequency Protection and Ride-through

Voltage and frequency protection requirements for all Generator Facilities are outlined in ISO-NE's Default IEEE 1547-2018 Setting Requirements in Appendix D. The default settings are a settings profile adopted by all New England utilities in order to establish specific area protection requirements to ensure robust and predictable performance of DER for events on the bulk power system. This can also help maintain bulk power system reliability with increasing DER penetration. The ISO-NE requirements include:

1. Over and under frequency trip thresholds and time delays for abnormal conditions
2. Frequency ride-through settings
3. Grid Support interactive inverter functions
4. Return to service time delays
5. Over and under voltage trip thresholds and time delays for abnormal conditions
6. Voltage ride-through settings
7. Frequency droop (frequency power) settings

The settings presented are required default settings. Settings for individual Generator Facilities may need to be adjusted on a case-by-case basis per Versant's requirements. All DER projects of all sizes with Interconnection Applications submitted prior to the implementation date of the ISO-NE default settings are exempt from these default requirements as outlined in Appendix D, however, are required to meet the ride-through requirements listed in the ISO-NE Source Requirement – 2018 document.

6.19 Synchronization

An approved automatic synchronizer and synchronization blocking device is required for DER to ensure that the DER Facility does not connect to energized Versant equipment out of phase.

Interconnection of the DER Facility will be blocked or otherwise prevented if the Versant distribution system power supply is outside the normal operating range. DERs capable of self-excitation must only interconnect once the frequency, voltage and phase angle are within the ranges listed in IEEE 1547-2018.

DERs that do not produce fundamental voltage, such as grid-following inverter-based DER, induction machines, and doubly-fed machines with excitation systems controlled by electronics that match the supply voltage magnitude, frequency and phase angle may use this functionality to achieve synchronization requirements.

Synchronizing schemes must be submitted to Versant for review and approval prior to installation. DER Facility synchronizing schemes must also take into consideration automatic reclosing on Versant distribution system facilities.

The generator shall designate one or more synchronizing devices such as motorized breakers, contactor/breaker combinations, or a recloser to be used to connect the Generating Facility to Versant's system. This synchronizing device could be a device other than the interconnection-interrupting device. The synchronizing device must be capable of interrupting the current produced when the Generating Facility is connected out of phase with Versant's distribution system consistent with IEEE 1547. All synchronizing will be done by the generator at the Generating Facility. The Generating Facility shall not be used to energize a de-energized Versant circuit. In-line breakers without synchronizing devices require mechanical interlocks to prevent out-of-phase closing with Versant's EPS. Synch-check relays are not acceptable synchronizing devices.

For circuits with significant DER installed, Versant will install synch-check relaying at the feeder breaker, at the generator's expense.

6.20 Anti-Islanding Protection

Intentional island operation is not allowed on the Versant distribution system. Anti-islanding protection is required to meet the following protection requirements:

1. Ensure other customers do not experience power quality problems
2. Prevent out-of-phase reclosing of the Versant distribution system with the Generator Facility
3. Reduce the safety hazard risk caused by unintentional island conditions

All DER Facilities shall have anti-islanding protection and shall automatically disconnect from Versant's EPS within 2 seconds upon the loss of voltage in one or more phases. This may require different protection functions, however, all DER Facilities shall have:

1. Over/under frequency protection
2. Over/under voltage protection

Inverter-based generators shall contain both passive and active anti-islanding protection. Anti-islanding protection will be tested within the TDS when a full impact study is required. A transfer trip scheme (DTT) will be required at the generator's expense if the generator fails its TDS islanding test.

If DTT for loss of substation source is required as a result of the TDS, this may require Versant to install fiber to the substation from the transmission source or other paths at the generator's expense.

6.21 Open Phase Protection

The Generator Facility interconnection protection must be capable of detecting the loss of any phase to which it is connected that occurs within the Generator Facility or on the interconnected feeder. Open-phase protection is required to prevent uncontrolled voltages from appearing on conductors isolated from the Versant source of supply. The probability of open-phase conditions is higher when interconnected to a section of Versant's distribution system that utilizes single-phase tripping. The islanded phase conductor can be energized by the Generator Facility, but the voltage will not be regulated and can be expected to deviate outside acceptable limits.

An open-phase conductor can also be energized when a Generator Facility is not connected and the conductor is backfed by the remaining connected phase conductors via a three-phase GSU transformer. This backfeed produces abnormal voltages and, in some cases, extreme overvoltages associated with ferroresonance can occur if the GSU transformer is ungrounded and there is significant phase-to-ground capacitance on the open phase circuit.

In both cases, the voltage on the open-phase distribution system conductor will pose a safety hazard to maintenance personnel and will not be maintained within acceptable limits.

Upon the detection of an open phase condition, the generator protection shall:

1. Disconnect the generation from the EPS within 2 seconds
2. Disconnect the GSU transformer from the EPS with a three-phase interrupting device

6.22 Underfrequency Load Shed Protection

Underfrequency Load Shed (UFLS) protection is required by NERC and is enforced by ISO-NE for stability of the bulk power system. The amount of load shed capacity cannot be reduced and is strictly enforced.

Existing UFLS schemes on Versant's distribution circuits will be reviewed to determine whether the scheme will operate properly with the Generating Facility operating. Changes required to an UFLS scheme to allow proper operation will be at the generator's expense. This applies primarily to Level 4 DER Facilities. Further, the generator will be responsible for the cost to relocate the load shed capacity that is offset by the generator's maximum output. This may include Versant installing one or more reclosers on other feeders to recapture the amount of load shed capacity displaced by the generator. Due to high penetration of DERs throughout the Versant distribution system, there are limited options for UFLS relocation.

6.23 Automatic Load Transfer (ALT) Schemes

Versant Power employs numerous ALT schemes across many of our distribution circuits and transmission lines to improve reliability to customers. DERs of any size that may negatively impact ALT scheme operation and those generators that were not studied for alternate circuit configurations will be required to remain offline during ALT scheme operation (transfer to a backup source/feeder). Existing ALT schemes will be reviewed by Versant to determine whether the scheme will operate properly with the Generating Facility operating. Changes required to the ALT scheme to allow proper operation, as well as any costs to evaluate impacts, will be at the generator's expense. A three-phase recloser with SCADA capability may be required for smaller Generator Facilities if necessary to enable DTT during ALT scheme activation.

Table 6-3: ALT Integration Criteria by DER Size

Generation Capacity	Criteria
< 25 kW	ALT integration not required.
26 kW-249 kW	ALT integration not required unless Engineering determines an ALT study is required to confirm generator impacts due to system constraints.
250 kW–499 kW	ALT integration required. ALT study is necessary to determine integration is not required.
>500 kW	ALT integration and ALT study are required.

6.24 Conservation Voltage Reduction (CVR) Schemes

Existing or planned CVR schemes on Versant's distribution circuits will be reviewed to determine whether the scheme will operate properly with the DER Facility operating. Changes required to the CVR scheme or the DER Facility to provide proper operation will be at the DER Owner's expense.

6.25 Distribution Voltage Reduction

For the purposes of system stability, Versant Power may reduce its voltage level by an additional 5% via automatic voltage reduction schemes or manually by the System Operator during times of system capacity emergency or during designated test periods.

6.26 High Speed Protection

The DER Facility may be required to use high-speed protection if time-delayed protection would result in degradation to the existing sensitivity or speed of the protection systems on Versant's EPS. DTT via fiber is required under these circumstances.

6.27 Exceptional Interconnection Protection

Application dependent protection elements and/or schemes not listed in the Technical Interconnection Requirements may be required. The Versant EPS, site-specific parameters or interaction of the Versant EPS and DER Facility may require other protection elements and schemes not listed in this document.

7 Equipment Ratings and Requirements

The DER Facility equipment must meet the following ratings and requirements:

1. Comply with the applicable regulations, codes, standards, MPUC rules and Versant Power equipment standards.
2. Be maintained to ensure all performance requirements in this document are met
3. Not exceed Versant Power's equipment ratings.
4. For DER Facilities with 100 kW or larger aggregate, PCC and POI interrupting devices shall be required to take into consideration external trip requirements and status indication requirements. For example, molded case circuit breakers used for disconnecting means may require shunt trip and 52a/b status contacts, which are not typically standard equipment.
5. Any necessary modifications required due to the dynamic nature of the Versant EPS, not limited to but including interrupting device ratings, protection settings, ride through settings and controls, reactive mode changes (fixed Power Factor to another mode), voltage control settings changes (i.e., Volt/Var settings revisions), grid support functions, metering, monitoring or communications.

7.1 Isolation Device

1. The electrical isolation device must comply with the current revision of NFPA 70 National Electrical Code (NEC).
2. DER systems, or systems with multiple DER units, must have one disconnect means with the capability of isolating all DER units simultaneously and shall meet the following requirements:
    a. Capable of being de-energized from both the Versant EPS and the DER within the DER Facility
    b. Able to visually confirm if the isolation device is in the open or closed position
    c. Able to visually verify that the contacts are open (visible break)
    d. Capable of being operated at rated power transfer
    e. Capable of being physically locked in the open position
    f. Have a manual override
    g. Capable of being operated with a fault on the EPS
    h. Not expose the operator to any live parts
    i. Bear a physical warning label that indicates the device can be energized from sources on both sides
3. Isolation devices for a three-phase DER Facility rated in aggregate of 250 kW or greater shall be a gang-operated airbreak loadbreak switch with the following requirements in addition to 1 & 2 above:
    a. Be readily accessible by Versant Power at all times, including utility truck access
    b. Lockable by Versant in an open position
    c. Not have any keyed interlocks
    d. Be located at the PCC (or alternate location as directed by Versant)
    e. Be located electrically upstream of all transformers, DERs and HV ground sources

f. Contain a ground (switching) mat installation per Versant Power Distribution Construction Standards
g. Contain a pipe-type operating handle with isolator

7.2 Interrupting Device

All fault current interrupting devices must be rated according to both the fault levels of the Versant EPS and the DER Facility fault level contribution. The interrupting device used to disconnect the DER from the Versant EPS must operate fast enough to meet the timing requirement of the fastest protection element.

An overcurrent protection device is required to automatically disconnect the DER Facility from the Versant EPS for faults on the DER Facility line or equipment as outlined below:

1. For DER connecting to a Versant three-phase feeder, the overcurrent protection device must be three-phase gang operated.
2. The typical preferred three-phase overcurrent protection device is a utility grade recloser and control.
3. If a recloser is used, automatic reclosing shall be disabled.
4. Pad-mounted switchgear is not allowed as a PCC overcurrent protection device due to the risk of faults on the underground cable and impact to Versant EPS reliability, however, an exception may be granted if the conditions below related to a padmounted interrupting device are met.
5. The Versant utility POI protective device will be a pole-mounted recloser. Versant does not use padmounted reclosers.
6. The settings shall be coordinated with the timed elements of upstream protective devices and shall be sensitive enough to operate for minimum Versant infeed to faults on the DER Facility line.
7. Generators 250 kW to 499 kW will require a customer-owned three-phase recloser for primary HV protection. These kW thresholds are subject to engineering discretion based on other system considerations.
8. Generators smaller than 250 kW may have fuses for primary HV protection unless the operation of one fuse could create an unbalance condition affecting other customers.

Generators 500 kW and larger will require a Versant POI recloser with SCADA for redundant protection in addition to the generator's primary HV interrupting device. Note that the Versant device is not to be relied upon for overcurrent protection of the generator lead. If interconnecting to a circuit with an ALT Scheme (Automatic Load Transfer), generators 100 kW and larger may require a Versant POI recloser with SCADA for disconnecting the Generator Facility during ALT Scheme operation.

The location of the overcurrent protection device must be as close to the PCC as practical. It should be on the first pole after the PCC. The generator lead length between POI and PCC is to be kept as short as practical to minimize line exposure upstream of the DER overcurrent protection device. The PCC pole is typically used for the DER disconnect switch with the next pole used for the DER overcurrent protection.

For DER 500 kW and greater, the typical generator lead equipment line-up from the POI is:

1. Versant POI pole and solid blade disconnects
2. Versant primary meter, station class arresters and pole
3. Versant recloser, recloser control, SCADA and pole
4. DER owned airbreak/loadbreak gang-operated switch, switching mat and pole at the PCC
5. DER owned recloser, recloser control and pole

The DER Owner shall be responsible for the installation, operation and maintenance of the loadbreak switch, overcurrent protection device, line facilities and everything beyond the PCC including the access road and vegetation management for the line.

If the DER facility opts to install a padmounted interrupting device, Versant approval may be granted if all of the following conditions apply and/or are met:

1. DER owner will execute an interconnection agreement acknowledgement that the AC underground primary cable serving the DER Facility will not have primary protection.
2. Versant Power does not accept liability for any damage to the DER Facility equipment.
3. The DER Facility is responsible for any damage to other customers' equipment or Versant Power equipment should it occur due to the lack of a primary protection device located upstream of the DER Facility's primary riser and underground cable system.
4. The device control shall have a utility grade relay suitable for generator interconnection protection, be programmed for all required protection and ride-through settings, and have appropriate VT & CT inputs.
5. The device must be capable of interrupting the fault current required, provide three-phase tripping, and no reclosing.
6. The device shall meet the requirements for inrush mitigation.
7. The device shall be no more than 75 feet laterally from the PCC GOAB switch.
8. The device shall meet witness test requirements without exception.
9. The Versant POI recloser has to be in operation for the project to interconnect and operate.
10. Modifications to the DER Facility POI design will be necessary if the device is unable to meet performance requirements.

Refer to Section 12 for more details related to design and location of the POI equipment, line and driveway for a DER Facility.

7.3 Interconnection Transformer

An interconnection transformer may be located between the DER Facility and the PCC and is used to step up or step down the DER's voltage for the interconnection with the Versant EPS. The transformer selection affects voltage regulation, fault current contribution and harmonic current flow on the Versant EPS. If an interconnected transformer is required, the following restrictions must be implemented by the DER owner:

1. The DER interconnection transformer must not cause voltage disturbances or disrupt coordination of Versant's EPS ground fault protection.
2. The interconnection transformer shall have one of the configurations outlined in Section 7.3.1. Other connections may be allowed as long as they are electrically equivalent.
3. The DER Owner shall ensure that there is no back-feed from the interconnection transformer when the generator is out of service and shall be responsible for such back-feeds.
4. The interconnection transformer may supply unbalance current to support the unbalanced load on the Versant EPS even when the generator is out of service. The DER Owner is responsible to ensure the design is adequate to handle the unbalance current.
5. Interconnection transformers are required to have off-load tap changers on their primary HV side with a minimum range of +/- 2.5% of rated voltage.

7.3.1 Interconnection Transformer Configuration

The DER Facility shall connect to the Versant EPS using one of the following options (refer to Appendix B for typical single-line diagrams and interconnection types):

1. Grounded-Wye/Grounded-Wye for facilities less than 250 kW in capacity, typically Type 1, Type 2 and Type 3.
2. Grounded-Wye/Wye or Grounded-Wye/Grounded-Wye with an HV Grounding Transformer as shown for Type 4-1, typical for inverter based DER.
3. Grounded-Wye/Grounded-Wye for solidly grounded generators as shown for Type 4-2.
4. Grounded-Wye/Delta as shown for Type 4-3.
5. For customer facilities adding co-generation, Delta/Grounded-Wye with a HV Grounding Transformer as shown for Type 5-1.

7.4 Grounding Transformers and Supplementary Grounding Devices

Grounding transformers may be included in the generator's design or may be required according to SIS, PCS and TDS results. Typically they are required to prevent overvoltages associated with unbalanced faults or help mitigate transient overvoltages (TrOV). Grounding transformers are included in projects to provide a source of ground fault current during line-to-ground faults and to limit the magnitude of over-voltages when ground faults occur in ungrounded wye or delta connected systems. Grounding transformers shall be in service at all times the generator is in service. To assure compliance, grounding transformers require a positive electrical interlock to be installed with the associated generator so that if it is removed, the generator cannot operate. The electrical interlock must be failsafe, such that any circuit or device failure will result in a safe mode of operation (generator disconnected at the PCC). If the grounding transformer is fused and not solidly connected, the fuse shall be monitored and the DER Facility's primary interrupter shall be tripped in the event of a grounding transformer failure.

The continuous rating of supplementary grounding devices shall be able to handle the maximum expected voltage unbalance with margin. Per Versant's conditions of service, the voltage unbalance on Versant distribution feeders can reach 5%.

Therefore, supplementary grounding devices should be sized for a minimum of 5% continuous voltage unbalance. The short time (5 seconds) fault rating shall be sized for the maximum fault current that will flow through the grounding device for a close-in fault.

Further, the addition of supplementary grounding devices for a DER Facility shall not desensitize the utility ground fault protection by more than 10%. This will be confirmed as part of the PCS.

For grounding banks connected on the high side of the GSU, utilizing a live-front grounding transformer configuration (i.e., bushings with bolted connections) vs. dead-front (i.e., insulated elbow connections) is an acceptable alternative to installing an electrical interlock. If the live-front grounding transformer is removed from service, the associated generator cannot operate so a positive interlock is achieved. The grounding transformer bushing connections can be either live-front or dead-front if an electrical interlock is installed.

7.5 System Grounding

The DER Facility shall design their interconnection facilities in accordance with the following system grounding considerations to prevent voltage excursions and clearing of ground faults:

1. The grounding of the DER Facility shall not cause overvoltages that exceed the rating of equipment connected to the Versant EPS.
2. The grounding of the DER Facility shall ensure that TrOV limits in Section 7.12 are not exceeded.
3. The grounding of the DER Facility shall not disrupt the coordination of ground fault protection of Versant's EPS.
4. The DER Facility's grounding shall be per manufacturer's recommendation and the requirements of Section 7.6 of the Interconnection Requirements.
5. If the primary HV winding of the DER Facility interconnection transformer is grounded or a grounding transformer on the HV side is installed, the ground grid of the DER Facility shall be connected to Versant's (grounded) system neutral.
6. DER Facilities with a grounded HV interconnection transformer utilizing a neutral reactor or grounding transformer connected to the HV neutral, shall be sized to ensure that TrOV limits are not exceeded and to ensure the impact to ground fault protection coordination in Item 3 above is met.

Versant multi-grounded four-wire distribution feeders are considered effectively grounded for all system conditions when the following two conditions are met:

- The ratio of zero-sequence reactance to positive-sequence reactance is positive and less than 3 ($X0/X1<3$).
- The ratio of zero-sequence resistance to positive-sequence reactance is positive and less than 1 ($0<R0/X1<1$).

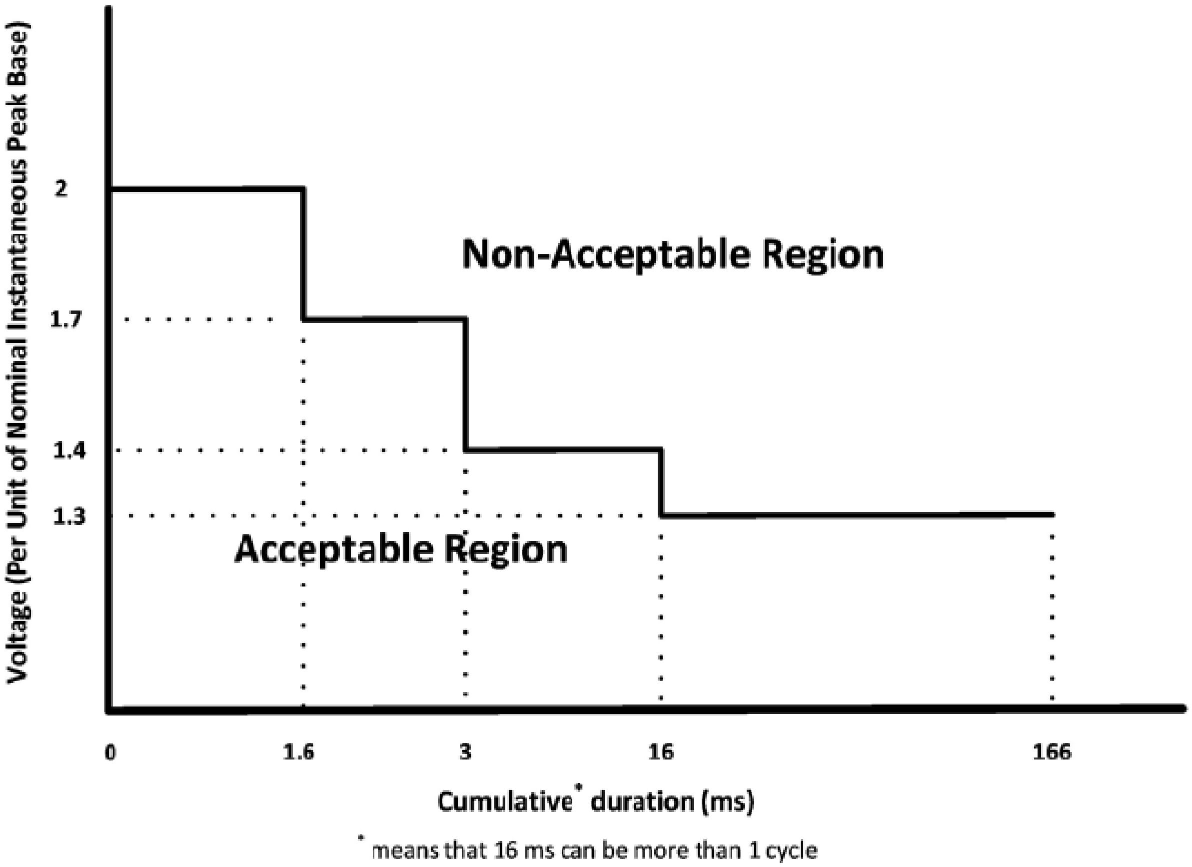
7.6 NEUTRAL GROUNDING

DERs are often connected through a step-up transformer. Based on transformer configuration, facility isolation devices and isolation schemes, it is possible to create ungrounded zones within the Utility and/or customer distribution systems. These ungrounded zones pose risk to safety and equipment in the form of transient over-voltages and non-detection zones. The DER Facility shall design neutral grounding solutions in accordance with the following as applicable:

- NFPA 70 National Electrical Code
- IEEE C62.92.1 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part 1 – Introduction
- IEEE C62.2 IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems
- IEEE C62.6 IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Supplied by Current Regulated Sources

Neutral grounding shall be considered to ensure voltage ratings of equipment and surge protection device ratings are not exceeded. Refer to IEEE 1547-2018 Section 7.4, Limitation of Overvoltage Contribution and Figure 7-1 below:

Figure 7-1: IEEE 1547-2018 Section 7.4.2 Limitations of Cumulative Instantaneous Overvoltage



7.7 Batteries / DC Supply

The DER Facility must include battery backup systems to meet the following requirements:

1. All protective devices must have battery backup systems to ensure operation of all protective functions in the event of a power failure for the appropriate time required to fully disconnect the DER Facility from the Versant EPS.
2. All battery backup systems must be capable of sustaining SCADA and telecommunications equipment to prevent telemetry outages between the DER Facility and the Versant System Operator (where Versant's communication equipment has to be installed beyond the PCC) for a minimum of eight hours.
3. In the event of a failure of the battery backup system or the battery voltage, the protection scheme will be considered failed and the DER(s) and HV ground sources will be disconnected from the Versant EPS.
4. Relays connected to the DC supply must not be subject to sustained overvoltage if there is a possibility that the DC rating of the equipment will be exceeded. To

prevent this, steps must be taken by the DER Owner to ensure that the DC voltage limiting devices are installed at each relay.

7.8 Surge Withstand

The protection, control and communication equipment of the DER Facility interconnection system must not fail, misoperate, or provide misinformation due to voltage or current surges. The DER Facility's interconnection system must have the following capability to withstand voltage and current sources in accordance with the environments defined in the following IEEE standards:

- IEEE/ANSI Std. C62.41.2 IEEE Recommended Practice on Characterization of Surges in Low-Voltage (1,000V and less) AC Power Circuits
- IEEE Std. C37.90.1 IEEE Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus – Description
- IEEE Std. C57.13:2016 – IEEE Standard Requirements for Instrument Transformers

7.9 Insulation Coordination

The generator facility design shall mitigate and prevent possible damage due to lightning, switching surges, TrOV and GFOV with use of appropriately rated arresters for the application (at a minimum intermediate class). Versant may as a result of the TDS require arresters (connected line-to-ground and/or line-to-line) to mitigate the generator-caused TrOV and GFOV:

1. The DER Facility shall be protected against lightning and switching surges.
2. Surge arresters shall be located as close as possible to the equipment they protect and shall have adequate ratings to withstand the TrOV during single-line-ground faults and load rejection events.

Versant standard arrester ratings are shown in Table 7-1:

Table 7-1: Versant Power Arrester Ratings

System Voltage (kV)	Arrester MCOV (kV)	Duty Cycle Rating (kV)
7.2 / 12.47	7.65	9
7.62 / 13.2	8.4	10
19.9 / 34.5	22	27

*Line-to-ground distribution system arresters

7.10 Ferroresonance

Versant Power requires that ferroresonance and other types of resonance be considered in the design of the DER Facility. If resonance problems arise, the DER Owner in collaboration with Versant must conduct a comprehensive study to determine the cause and mitigate the effects. The DER Owner will demonstrate mitigation by providing a written report to Versant.

7.11 Phasing

The DER Facility must connect rotating machines, as required, to match the phase sequence and direction of rotation of the Versant EPS.

7.12 Transient Over-Voltage TrOV

Grounding of DER Facilities and connection systems shall be in accordance with Section 7.5 and not cause any voltage disturbances. TrOV that may be caused by the DER Facility connection should not exceed 125% of nominal system voltage (line to neutral) anywhere on the Versant EPS and under no circumstance shall exceed 138%.

Versant may advise on action needed to reduce TrOV limits by specifying the requirement of a grounding transformer and/or arresters on the HV side. Fast inverter detection and response settings (SPOV) may also be specified to mitigate TrOV.

7.13 Power Quality Monitoring Device

1. Versant Power may require DER Facilities larger than 250 kW in aggregate to be equipped with a Power Quality (PQ) monitoring device capable of providing the reports required in Section 11.2.
2. If required, Versant will procure and install, at the DER Owner's expense, the PQ monitoring device near the POI.

7.14 Protection from Electromagnetic Interference (EMI)

1. EMI shall not cause the protection, control and communication functions of the DER Facility interconnection to fail, change state, misoperate or provide inaccurate information.

2. The DG Facility interconnection must have the capability to withstand electromagnetic interference (EMI) environments in accordance with ANSI/IEEE Std. C37.90.2, IEEE Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

7.15 Voltage Relays

Voltage relays shall be frequency compensated to provide a uniform response in the range of 40 to 70 Hz. In addition, voltage relays that are Utility Grade or certified and can be connected directly to the primary HV without a VT are acceptable to Versant.

7.16 Protective Relay Hard-Wire Requirement

Unless otherwise approved by Versant, protective relays shall be hardwired to the device they are tripping. Further, interposing computer or programmable logic controllers or the like are not permitted in the trip chain between the relay and the device being tripped. Test switches are allowed in the tripping circuit and should be installed to accommodate witness testing.

7.17 Current Transformers

CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are consistent with Versant's practices. The appropriate relay class or meter class CT shall be applied for the intended purpose.

CT specifications shall be provided for all synchronous DER applications including accuracy class, voltage class, ratios, wire connection size and length.

7.18 Voltage Transformers

The DER Facility may be required to be equipped with a direct voltage connection or a voltage transformer (VT) connected to Versant's side of the interrupting device to detect the applicable voltages with regard to the reference point of applicability. For three-phase applications, a VT for each phase is required. All three phases must be sensed either by three individual relays or by one relay that contains three elements. If the voltage on any of the three phases is outside the bounds accepted by Versant, the unit shall be tripped. If the Generating Facility's step-up transformer is ungrounded at Versant's EPS voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground.

The steady state voltage measurement accuracy of the DER Facility's voltage sensing equipment for protection-related functions shall be not more than +/- 1% accuracy. The minimum accuracy for transient voltage measurements is +/- 2%. Low Energy Analog (LEA) sensors are not acceptable for protection functions and are not acceptable for voltage sensing for PPCs.

7.19 Inverter Based DER

Versant Power requires UL 1741 SB (including IEEE C62.41) certification for the electrical protective functionality of independent power systems. UL 1741 compliance is established by UL and other Accredited, Nationally Recognized Testing Laboratories. All inverter-based interconnections must also follow the requirements in the ISO-NE Default IEEE 1547-2018 Setting Requirements in Appendix D.

It is the DER Owner's responsibility to submit documentation that the proposed DER Facility has been certified.

For Generating Facilities utilizing photovoltaic technology, the system must be in compliance with IEEE 929 specifications and requirements.

Unless otherwise approved by Versant Power, protective relays required by these Guidelines must be certified to UL 1741 SB and conform to IEEE C62.41.

The generator must submit to Versant the settings for all relay functions or adjustable inverters or controller's protective functions for the DER Facility's protective devices and control functions that affect the interconnection with Versant. This information must be included on the single-line diagram.

7.20 Momentary Paralleling of Standby Facilities

This section is only applicable to DER facilities that are in parallel for six cycles or less (closed transition) or open transition. Such DER facilities are considered to be non-parallel, non-export DER facilities.

Synchronization systems, where required, must follow the requirements outlined in Section 6.19.
The DER Facility connecting for six cycles or less must include the following:

- Undervoltage protection to ensure that the generator is not capable of energizing the Versant EPS if the system is de-energized
- A failsafe operation to ensure that the DER Facility will not operate in parallel with the Versant EPS for more than 30 cycles

A closed transition scheme is not allowed on Versant's low voltage network systems or on "spot" network systems.

The closed transition scheme and transition equipment used by the DER Facility must be reviewed and approved by Versant before operation of the generator. The closed transition scheme must provide voltage, frequency, and phase angle matching as appropriate to provide a smooth transition. It must also provide maximum paralleling time protection. Once a generator starts and the generator switch/breaker closes, paralleling the generator and Versant's EPS, the line switch/breaker must open within 0.5 seconds (maximum). After the utility power is restored, the scheme must open the generator switch/breaker within 0.5 seconds after the line switch is closed, paralleling the generator with VP's EPS.

Protection relays to isolate the Generating Facility for faults in Versant's EPS are not required if the paralleling operation is automatic and takes place for less than 0.5 seconds. The maximum paralleling time protection must be provided by a separate device from the equipment used for control and paralleling of the generator and operation of the transfer switch. A discrete timer (60 cycles) is required, powered by the generator battery, to trip an interrupting device, which may be the generator breaker. This requirement will provide failsafe operation should the control equipment misoperate.

If the paralleling operation takes place at 0.5 seconds or greater, the full complement of relays required for a synchronous generator may be required by Versant.

The generator, as a minimum, must perform the following functional tests after the transfer equipment has been energized, but before the closed-transition transfer is allowed on Versant's EPS as a normal operation:

- Voltage, frequency, and phase rotation
- Transfer test (maximum paralleling time must not exceed 0.5 seconds)
- Excessive parallel time test (when the VP source switch fails open, the generator must be shut off and vice versa)
- VP must be notified 10 business days in advance of the testing so that it may, at its option, have its personnel observe the testing and/or inspect the installation

Before the approval of closed-transition transfer is granted by VP, the generator must provide to VP a report attesting to the successful completion of the above testing. Upon receipt of the approved test and inspection reports, and verification of the local Electrical Inspector's approval, VP will issue a written notice of approval of closed-transition transfer to the generator.

8 Additional DER Considerations

8.1 Inverter Specifications

Inverters used for power conversion in DER Facilities shall meet all applicable industry standards including IEEE 1547.1-2020, UL 1741 SB and ISO-NE Default IEEE 1547-2018 Setting Requirements.

The DER Facility Developer will need to provide full specifications of the inverter model(s) to be installed including reactive power capability and short circuit data. For DER Facilities 5 MW or greater, a detailed dynamic model in the Siemens PSS/E format shall also be provided. The model must be from the list of NERC-approved models and not a user-defined model.

The DER Facility Developer will need to provide a working PSCAD model for any inverters as part of an SIS to complete a Time Domain Study. A PSCAD model validation process will be completed before commencement of the SIS.

Inverters shall be able to meet the reactive power requirements per Section 6.6 and range of reactive control as specified by the SIS and/or the VVO study.

8.2 Energy Storage Systems (ESS)

Various types of ESS may be considered that connect in parallel to the Versant EPS. ESS is common for DER applications where the primary benefit enables DER Facilities to be dispatched upon request behind the meter (BTM). In these cases, the ESS is charged by the DER Facility to be available later to dispatch the stored energy when the DER Facility is not generating. Customers may also apply ESS where there is no DER Facility to take electricity from the Versant EPS as a load during off-peak times when rates are lower, store the electricity, then use the BTM stored electricity during peak times when rates are higher.

ESS has the potential for significant effect on the load flow of the area EPS and the overall dispatch characteristics of the network. An ESS can be complemented by smart inverter technology at the PCC which could also affect the EPS. Under such circumstances, it is critical to understand the operating characteristics of the ESS, including import and export intervals, as well as equipment power ratings, controls and capabilities. Additional information may be required at the time of application for interconnection such as:

- Nameplate rating of the ESS.
- Stand-alone or integrated with generation
- Method of ESS connection, whether (1) directly connected to the Versant EPS; (2) DER & ESS DC coupled; (3) DER & ESS AC coupled; (4) ESS on utility line side of the service point and revenue meter; and (5) ESS on load side of the service point and utility revenue meter with the premises load, as applicable to the proposed system
- Description of how the ESS will be charged (grid only, unrestricted or restricted from the grid and associated generation, or from the generation only)

- Description of any export control methods and operational profile narrative. (See also Section 6.7 C. 3.)
- Sequence of operation for the charging and discharging capabilities of the ESS and the maximum ramp rate in Watts/second
- Inverter UL 1741 SB certification documentation or utility grade intertie relay with the required IEEE 1547 functions, settings and islanding protection
- Service configuration and revenue metering provisions shall meet Versant's requirements
- Description of any markets the ESS will participate in including ISO-NE wholesale markets and/or state programs

8.2.1 ESS Coupled with NEB Resources

Energy storage may be paired with an NEB resource so long as there are controls in place that prevent the ESS from being charged from the Versant EPS, or if the ESS is capable of charging from the EPS, controls are in place which would prevent the ESS from discharging to the EPS. For DER Facilities greater than 100 kW that are paired with ESS, the customer must submit an annual attestation affirming that the controls necessary to prevent the ESS from being charged from the EPS remain in place. Versant will initiate the annual attestation process and will track responses. In the event the customer does not provide the annual attestation or is found to have removed or modified the controls such that the ESS can be charged from the EPS, then (i) the customer will be deemed ineligible to participate in Net Energy Billing, and (ii) Versant Power may immediately terminate the Agreement without following the Breach provisions within NEB Agreement.

8.3 SUBTRANSMISSION AND FERC JURISDICTIONAL INTERCONNECTIONS

Technical requirements for generating facilities interconnecting to Versant Power subtransmission, transmission, or BES are specified by: (1) Versant Power on a case-by-case basis, and (2) ISO-NE's Operating Procedure No. 14. More specifically, interconnection requirements may include:

1. Protection schemes
2. Special protection schemes
3. Telemetry, RTUs & SCADA
4. Reactive support
5. Automatic Voltage Regulation (DER >5 MW)
6. Revenue metering
7. Electronic Dispatch Capability (EDC)
8. Voltage control
9. Governor control

Subtransmission interconnections may require installation of a switching station consisting of a three-breaker ring bus and other possible upgrades necessary for the appropriate operation of the Versant EPS. A fiber path for protection functions and communication may also be required for direct interconnections to subtransmission and DER Facilities interconnecting to distribution side lines tapped to subtransmission.

9 Operating Requirements

This section describes the minimum requirements that the DER Facility connected to the Versant EPS must comply with when the DER Facility is in operation. Failure to comply with the specified requirements will lead to disconnection of the DER Facility from the Versant EPS. An Operating Procedure between the DER Facility and Versant Power may be required as deemed necessary by Versant.

9.1 General Requirements

1. The DER Facility must disconnect all DERs in the event there is a configuration change to the Versant EPS not studied or approved in the DER interconnection process.
2. All DERs must be disconnected and remain disconnected during planned and unplanned system events or as directed by the Versant System Operator.
3. The DER Facility is not allowed to operate should the Versant POI recloser not be operational.
4. All switching between the Versant System Operator and the DER Facility involving the manual operation of an airbreak switch will require the prior disconnection of any interconnected DER from the Versant EPS. This switching will be directed by the Versant System Operator.

9.2 Reconnection of DER following an outage or shutdown

The DER reconnection to the Versant EPS will be allowed by Versant under the following circumstances:

1. The DER Facility with generation offline may manually reconnect to a distribution feeder within five minutes using the DER Facility-owned recloser, provided that the following conditions are met:
    - The distribution feeder has successfully re-energized by the original feeder source and the distribution voltages are within normal voltage operating limits for a constant period of 5 minutes.
    - The fault is not downstream of the PCC.
    - A Versant EPS recloser has not activated after a DER protection or DTT scheme has not tripped the facility.
2. Automatic DER reconnection for DER facilities <u>with</u> a Versant POI recloser, which are typically 500 kW and larger, is not allowed and will be reconnected under the following conditions:
    - The distribution feeder has successfully re-energized by the original feeder source or alternative source (only if prior approval via study), and the distribution voltages are within normal voltage operating limits for a constant period of 5 minutes.
    - The fault is not downstream of the PCC.
    - If the Versant POI recloser has communication and telemetry established with Versant's SCADA system.
    - Versant System Operator determines it is safe to reconnect the DER Facility and can initiate a manual close command via SCADA.
3. Automatic DER reconnection for facilities <u>without</u> a Versant POI recloser, which are typically smaller than 500 kW, will be allowed under the following conditions:

- The distribution feeder has successfully re-energized by the original feeder source or alternative source, and the distribution voltages are within normal voltage operating limits for a constant period of five minutes.
- The fault is not downstream of the PCC.
- Automatic DER reconnection is only permitted if the Versant POI SCADA equipment (if applicable) has communication and valid telemetry established with Versant's SCADA system.
- Versant EPS voltage is stabilized and within the normal voltage and frequency operating limits described in Section 2.2 and Section 2.4.

4. Permission from the Versant System Operator is required for the following reconnection:
    - DER facilities with Versant POI reclosers
    - DER facilities 500 kW and larger
    - Special design and operational considerations when connected to feeders with distribution automation. Sequencing and reconnection capability will be reviewed and approved by Versant on a case-by-case basis.

The DER may be required to adjust reconnection delay based on findings from the interconnection process, subsequent studies or if directed by Versant to mitigate power quality issues or ensure proper operation of the Versant EPS.

9.3 Single Connection Path

The DER Facility may only be interconnected with one connection path, with no alternate connection paths, except as specifically allowed for rooftop and small DER facilities without Versant SCADA capability. The connection path will be studied and clearly identified as part of the DER Facility's SIS and operating procedures. The DER Facility must comply with the following requirements:

- The DER Facility connection to the Versant EPS must be restricted to the "normal Versant distribution supply configuration" of the connection path.
- The Versant distribution feeder closest to the proposed DER Facility POI will be designated the normal distribution supply configuration of the connection path and will be the path the impact study is based on.
- If the Versant distribution system supply configuration of the connection path is abnormal, the DER Facility must be disconnected and remain disconnected until the normal configuration is restored.
- The DER Owner may request an additional connection path if the additional path is already an existing alternate feeder configuration (i.e., ALT scheme), subject to review and approval by Versant Power, and additional impact studies and possibly other studies will be required as a result.
- In the event an alternate connection path is approved, the impact study, operating procedures and Interconnection Agreement will be revised to include the approved alternate connection path.
- If the DER Facility receives approval for an alternate connection path, Versant System Operator will have final authority as to whether the DER Facility will be allowed to be connected during an alternate distribution system configuration.

9.4 ISLANDING

Intentional or unintentional islanding is not permitted with the Versant EPS. During an unintentional islanding event, the DER Facility must detect the island condition and cease to energize the Versant EPS within 2.0 seconds.

Islanding detection and protection requirements must be met. Refer to Section 6.20 for additional information on islanding.

9.5 SITE INSPECTIONS

Versant Power reserves the right to request an inspection and the DER Owner must grant access and allow the DER Facility to be inspected by Versant representatives to ensure compliance with Versant interconnection requirements.

9.6 MAINTENANCE

The DER Owner must maintain a quality control and inspection program using industry standard practice, good utility practice and OEM recommendations. Inspections must occur at least monthly. Versant Power reserves the right to request at any time an auditable log of these required inspections. All DER Facility equipment, up to and including the visible point of isolation (PCC), is the responsibility of the DER Owner. The DER Owner is responsible for maintaining the equipment to accepted industry standards.

The DER Owner is fully responsible for routine maintenance of the DER Facility control and protective equipment and the keeping of records of that maintenance.

Versant Power reserves the right to request, and the DER Owner must provide, a copy of the planned maintenance procedures and a maintenance schedule for the DER Facility interconnection protection equipment.

9.7 RELAY TESTING & MAINTENANCE

The DER Owner is responsible for periodic testing and maintenance of its DER Facility protection and control schemes, batteries and interrupting devices that protect the Versant EPS. The test cycle for protective relaying must not be less frequent than once every three years, or manufacturer's recommendation, whichever is less. The DER Owner must provide copies of these test records to Versant Power. Versant shall have the right to monitor periodic maintenance performed by the DER Owner and its representatives and contractors.

Each routine test shall include both a calibration check and an actual trip of the interrupting device from the relay being tested.

Inverters with field adjustable settings for their internal protective elements shall be periodically tested if those internal elements are being used by the DER Owner to satisfy the requirements of this protection policy.

9.8 Vegetation Management

The DER Owner shall apply good vegetation management practices and procedures to prevent interference of the DER Facility operation and routine maintenance. This includes vegetation clearing around overhead power lines serving the DER Facility and along private lines.

10 TESTING & COMMISSIONING

This section describes the minimum testing and commissioning requirements for the DER Facility interconnecting with the Versant Power EPS. The scope of this section covers testing for the interface equipment between the DER Facility and the Versant distribution system.

10.1 GENERAL REQUIREMENTS

The DER Provider is responsible for ensuring that the DER Facility complies with the testing requirements specified in this section. Versant reserves the right to require additional testing if deemed necessary for the DER Facility interconnection with the Versant distribution system.

The DER Facility's testing must meet the requirements of the following standards:

- IEEE Std 1547 – 2018: IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, Section 11 - Interconnection Test Specifications and Requirements
- IEEE Std 1547.1 – 2021: IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- UL 1741 - 2nd Edition inclusive of Supplemental A (SA) (2016): Advanced Inverter Testing addition to Standard for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources
- UL 1741 - 3rd Edition inclusive of Supplement B (SB) (2021) or later editions as required

The DER Provider must provide Versant Power with the specifications and a list of standards of the DER Facility interconnection equipment. The DER Owner will also compile and provide a testing plan for the DER Facility interconnection system to Versant for review and approval. The timing of the submission of the testing plan will be determined as part of the DER interconnection process. Versant will provide the DER Owner with comments and any requests for changes to the DER Facility's interconnection system in a timely manner. The DER Owner must address and respond to the Versant comments in writing and make the requested changes in a mutually agreed-upon time.

The DER Owner must notify Versant in writing at least three weeks before energization and start-up testing of the DER Facility. Versant shall have the right to witness the commissioning testing (pre-parallel testing) as defined in the IEEE 1547 and must be notified 10 business days in advance so that at its option may have Versant personnel observe the testing or inspect the installation. Additionally, Versant reserves the right to witness the testing of any equipment and protection systems associated with the DER Facility's interconnection.

10.2 TESTING

The following describes the three categories of DER Facility interconnection system testing:

1. Type Testing

2. Production Testing
3. Verification & Acceptance Testing

10.2.1 Type Testing

Type Tests are conducted by an independent testing laboratory (NRTL) on a sample of the DER Facility equipment to prove that the equipment complies with the standards listed in the equipment specifications. The manufacturer of the equipment must be able to provide a certified Type Test for every standard listed in the equipment specification data sheet. Versant reserves the right to request a copy of the DER Facility interconnection equipment Type Tests concurrently with the DER Owner submitting the DER Interconnection application and/or for any equipment added to or modified at the DER Facility interconnection system thereafter. Versant may require additional Type Tests to confirm that the DER Facility interconnection equipment complies with the applicable standards required for the DER Facility interconnection with the Versant EPS.

Minimum Type Tests requirements must include the following:

- Temperature stability
- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization or Entering Service
- Interconnection integrity
- Surge Withstand
- Islanding
- Open phase
- Reconnect following abnormal condition disconnect
- DC Injection (for inverters without interconnection transformers)
- Harmonics
- Voltage and power control requirements
- Flicker
- Loss of control circuit power
- AC output short circuit contribution tests
- Circuit unbalance test.

10.2.2 Production Testing

Production Tests are conducted at the equipment manufacturer facilities on every unit included in a DER Facility interconnection system. The Production Tests must confirm that the manufactured units configured with default settings are aligned with the equipment specification and performance requirements.

The minimum production test requirements must include the following:

- Response to abnormal frequency
- Response to abnormal voltage
- Synchronization or Entering Service

10.2.3 Verification & Acceptance Testing

Verification and Acceptance Testing will be conducted after the DER Facility interconnection system is installed, is ready for operation, and an executed Certificate of Completion has been submitted to Versant. The Verification and Acceptance Test will be conducted in coordination with Versant Power. The testing must be conducted in accordance with the testing plan submitted and approved by Versant during the design phase. Versant reserves the right to witness any or all the tests associated with the DER Facility interconnection system. The DER Owner must notify Versant in writing at least three weeks before the start of Verification and Acceptance testing.

10.2.4 Interconnection Verification and Inspection

The DER Owner must provide a copy of the test procedure, as-built electrical single-line and three-line diagrams (and relay diagram if applicable), and inverter settings in advance of the test day for Versant review. An individual qualified in testing protective equipment (professional engineer, factory-certified technician, or licensed electrician with experience in testing protective equipment) must perform commissioning testing in accordance with the manufacturer's recommended test procedures to prove the settings and requirements of this document. At the completion of the test, Versant must receive a copy of the test report data.

The testing plan, verification and evaluation tests must include (and are not limited to) the following:

- Certified relay testing including:
  - CT and CT circuit polarity, ratio, insulation, excitation, and continuity and burden tests
  - VT and VT circuit polarity, ratio, insulation and continuity tests
  - Relay pick-up and time delay tests
  - Functional breaker trip tests from protective relays
  - Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages
  - Breaker closing interlock tests
- Measurement location
- Measurement accuracy
- DER Facility interconnection capability
- DER Facility reactive power capability
- DER Facility voltage and power control capability
- DER non-export function if applicable
- Presence of a means of disconnecting the DER Facility from the Versant EPS
- Verification of the interconnection transformer winding
- Verification of the transformer neutral impedance grounding
- Verification that the neutral conductor is sized per $\geq$100% of the phase conductor size and is continuous from PCC or riser to the transformer H0 bushing
- Verification of the grounding coordination
- Verification ground connections use 2-bolt compression lugs
- For a three-phase system, verification of the phasing and phased rotation of the Versant EPS and the DER Facility
- Verification of the interrupting device capability

- Verification of the device rating
- Verification of the final DER Facility interconnection system protection settings
- Verification of the anti-islanding functionality
- Verification of inability to energize a de-energized line
- Verification of the synchronization and Entering Service criteria
- Verification of the instrument transformers parameters in accordance with the design
- Testing of the overall system including the protective relays, circuit breakers and telecommunications including DTT (if applicable)
- Load testing of the protective relays
- Verification of the DER Facility disconnection following loss of power supply, failure of protection system and/or breaker failure
- Verification of a failsafe DTT trip on loss of communication signal
- Verification that power and control wiring comply with drawings and manufacturer requirements
- Verification of compliance with the applicable Surge Withstand Capability (SWC) standards
- Verification of the energization cessation under the following conditions:
    - Abnormal frequency
    - Abnormal voltage
    - Protection system failure
    - Reverse power or minimum-power limitations

Additionally, the following verifications and inspections will take place, at the sole discretion of Versant:

- The DER Facility does not cause objectionable harmonic or voltage distortion.
- The DER Facility does not cause objectionable voltage flicker, typically with a delta-V test at full output and not exceeding a >2% voltage change.
- The DER Facility does not exceed the required ramp rate limit upon entering service or normal operation.
- The DER Facility does not cause objectionable voltage unbalance.
- The DER Facility must limit the injection of DC current into the Versant EPS.

10.3 SCADA COMMISSIONING

If SCADA is required by Versant, the equipment is typically installed within the Versant POI recloser to help minimize complications with coordinating design, space, access, installation, communications and maintenance within the DER Facility's equipment. SCADA commissioning by Versant will typically occur during the Versant POI recloser installation in advance of the DER Facility verification test.

In the limited number of DER Facility locations where Versant's SCADA equipment is installed within the DER Facility, the scope of commissioning will include verification of the correct operation, functionality and programming. Commissioning will be coordinated between Versant and the DER Owner to ensure the equipment is functional prior to the verification tests.

10.4 Switchgear & Metering

Versant Power reserves the right to witness the testing of installed switchgear and metering. The DER Owner must notify Versant in writing at least 10 days before any testing.

10.5 Marking & Tagging

Marking, tagging and other signage requirements will vary with the type and intent of the DER Facility. Versant standard practice should be followed.

10.6 Hardware or Software Modifications

Whenever interconnection system hardware or software is changed there can be an effect on equipment and functions listed below.

1. Recommissioning of equipment is required for all hardware changes affecting the interconnection listed as follows:
   - Switchgear and conductors
   - Protective relays
   - RTUs and sensors
   - Communication devices

2. A retest shall be required of all potentially affected functions including but not limited to the following:
   - Overvoltage and undervoltage
   - Overfrequency and underfrequency
   - Fault detection
   - Inability to energize a de-energized line
   - Time-delay restart after Versant Distribution System outage
   - Reverse or minimum power function (if applicable)
   - Synchronizing controls (if applicable)
   - Anti-islanding functions (if applicable)

10.7 Commissioning & Inspection

Versant Power reserves the right to request and the DER Owner must allow Versant to witness the construction and commissioning or any part of work related to the equipment being commissioned including inspection of materials, detailed drawings, documents (e.g., test plans, test logs), manufacturing operations and installation procedures, and to witness tests and evaluate results of the commissioning tests.

11 REPORTING REQUIREMENTS

11.1 OVERVIEW

The DER Facility rated in aggregate ≥5,000 kW interconnected with the Versant EPS must record the data specified below. The DER Owner must keep the recorded data for a minimum period of two weeks and provide it within five working days of a Versant request. These reports will be used by Versant to conduct technical reviews including load/generation profile surveys and disturbance analysis. Data for reporting requirements are recorded at the PCC, unless otherwise directed by Versant during the DER interconnection process.

Versant Power may also require installation of a power quality recording device for DER Facilities exceeding 250 kW in aggregate especially in areas of high DER penetration or may have known or anticipated PQ issues.

Please note that ISO-NE may have additional requirements for units rated in aggregate ≥5,000 kW.

11.2 POWER QUALITY REPORTING

The DER Facility subject to Reporting Requirements must install a Power Quality Recorder (PQR) at the PCC. The installed power quality instrument must be compatible with IEC Standard 61000-4-30 Class A – Power Quality Monitor: Development and Performance Analysis, and must be previously approved by Versant Power. The PQR must provide comprehensive information on all power quality parameters (e.g., voltage, current, harmonics, transient and voltage and current unbalance). The PQR must also perform the following functions:

- Record voltage and current at minimum 256 samples/cycle
- Trigger voltage and current waveforms, simultaneously on all channels, when any phase voltage is below 0.95pu or above 1.10pu of its nominal value
- Provide four pre-fault and two post-fault waveform values
- If the DER Facility is connected to a medium voltage system, a scaling factor must be applied to all power quality measurements to reflect the real values
- Record millisecond impulsive and low to medium frequency oscillatory transients as per IEEE Std 1159-2009 IEEE Recommended Practice for Monitoring Electric Power Quality - Section 4
- Report Pst and Plt values based on IEEE Std. 1453; IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
- Record voltage and current unbalance as defined in Section 6.4
- Recorded data must be provided to Versant in COMTRADE, PQDIF or requested file format.

12 DER Facility POI & PCC Site Design

12.1 Point of Interconnection (POI)

Several factors must be taken into consideration when designing the POI of a DER Facility such as:

- Access driveway design
- Utility vehicle turnaround
- Overhead line interconnection to Versant's existing distribution
- Versant and DER pole, conductor, guying and equipment layout
- Versant Distribution Construction Standards
- Right-of-way requirements
- Permitting and approvals
- Vegetation management
- Impact to neighboring landowners and any other stakeholders

Interconnection Site Plans submitted to Versant must have all final design details shown so Versant's POI design can be completed effectively and be properly coordinated with the DER Facility developer. Refer to Appendix E for Site Plan requirements.

12.2 Access Driveway Design

Please refer to Figure 12-1 below for POI access driveway design requirements. Safety of Versant workers utilizing the access driveway is critical. The design shall accommodate safe entrance and egress for Versant Power vehicles, comply with the authority having jurisdiction of the public way, be constructed to support utility vehicles, and allow for an adequate turnaround near the Versant equipment.

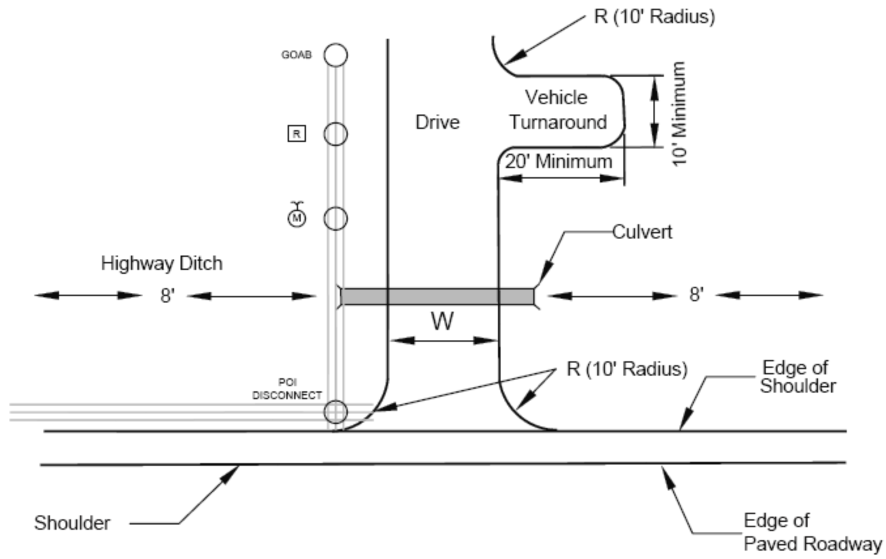
Access driveways shall be perpendicular to the interconnecting public way to provide visibility of each direction of the public way. For egress, nearby obstacles that prevent the ability to detect traffic along the public way shall be removed.

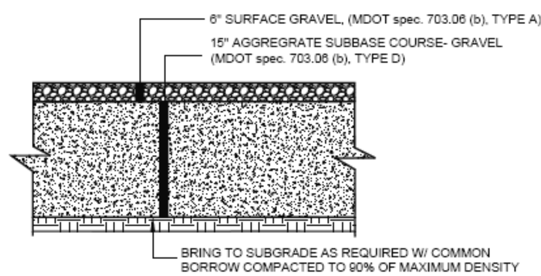
Access driveways shall be configured as follows:

- Minimum 15-foot width
- Minimum 5 feet away from POI utility poles (to allow for maintenance and snow removal)
- Maximum 15 feet away from the POI pole line (for access by Versant bucket trucks)
- A vehicle turnaround 10 feet by 20 feet located near the GOAB Switch (PCC) shall be provided
- No portion shall be located under power lines
- Subsurface and surface aggregate as shown in Figure 12-1 to provide adequate load-bearing capacity for Versant's vehicles

The DER Facility Developer shall obtain access driveway permits from the town or State prior to Versant seeking pole permits. An existing driveway may not meet the requirements of a DER Facility and should be permitted for a change of use in accordance with the new design.

ENTRANCE / DRIVEWAY DETAILS





NOTES:

1. COMPACT GRAVEL SUBBASE, BASE COURSE TO 95% OF MAXIMUM DENSITY USING HEAVY ROLLER COMPACTION
2. CONTRACTOR SHALL SET GRADE STAKES MARKING SUBBASE AND FINISH GRADE ELEVATIONS FOR CONSTRUCTION REFERENCE

GRAVEL DRIVEWAY DETAILS

NOT TO SCALE

GENERAL NOTES

1. THE MINIMUM RADIUS ON THE EDGES OF THE ENTRANCE AND TURN AROUND MUST BE 10 FEET OR AS OTHERWISE REQUIRED AS SHOWN.
2. ENTRANCES/DRIVEWAYS WILL BE BUILT WITH AN ADEQUATE TURN- AROUND AREA ON SITE TO ALLOW All VEHICLES TO MANEUVER AND PARK WITHOUT BACKING ONTO THE HIGHWAY. THIS TURN-AROUND SHALL BE AT LEAST 10 FEET WIDE BY 20 FEET LONG.
3. ENTRANCES MUST MEET ALL TOWN & STATE REQUIREMENTS AT INTERSECTION OF MAIN ROAD
4. NO PORTION OF ENTRANCE OR TURN AROUND SHALL BE PLACED UNDER POWER LINES
5. REFER TO DRAWING "GRAVEL DRIVEWAY DETAIL FOR MATERIAL SELECTION, DEPTH, AND COMPACTION

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Figure 12-1: Access Driveway Design

12.3 Pole & Equipment Layout

The typical sequence of POI equipment from the beginning of the generator lead at the main road to the DER Facility is as follows:

(1) Versant POI junction pole adjacent to the main road; contains (3) solid blade disconnects
(2) Versant POI revenue primary meter, pole and station class surge arresters
(3) Versant POI recloser, control, pole, SCADA interface and antenna (radio or cell)
(4) PCC located at the generator side terminals of the Versant POI recloser
(5) DER Facility pole with GOAB Switch
(6) DER Facility recloser and control
(7) DER Facility meter pole
(8) DER Facility riser pole
(9) Grounding transformer
(10) GSU transformer(s)
(11) DER surge arresters

The above pole layout shall be in a straight line. Spacing between Versant Power poles shall be a minimum of 30 feet to a maximum of 75 feet and shall be within visible sight from each other. All poles shall be a minimum of 5 feet and maximum 15 feet from the edge of the DER Facility access driveway. No Versant facilities shall cross or overhang adjacent landowners unless proper rights have been secured by Versant Power.

The design of the POI line and equipment shall be in accordance with Versant Power Distribution Construction Standards.

The DER Facility primary protective device shall be located as close as possible to the PCC. The Versant POI recloser does not serve as primary protection for the DER Facility. Refer to Section 7.2 for additional details and requirements related to when a padmounted primary interrupting device fed from unprotected primary underground is utilized.

SCADA, when required, will be installed within Versant's recloser control. There is no interface between Versant and DER Facility POI/PCC equipment. If a DER Facility owner requests kyz pulse data from the Versant revenue meter, Versant will provide and install an enclosure adjacent to the meter to terminate control cables from the DER Facility.

12.4 Right of Way (ROW)

An easement will be required for access to Versant equipment on private property. Typical activity includes installing new poles, equipment, and guying; trimming trees; reading meters; replacing equipment; repairing equipment; and ongoing maintenance. Versant does not provide strip easements. Easements are site specific, with accurate measurements from point-to-point and from pole-to-pole. Versant easements require a 15-foot setback; 15 feet on each side of poles, anchors, and conductors. This covers safety concerns and provides adequate access to safely maintain our equipment.

It is the responsibility of the DER Facility Developer to obtain all easements from all parties regardless of the legal status of the parcel. The Developer will provide regular progress updates to the Versant Project Manager and ROW Agent on obtaining easements. It is also the Developer's responsibility to identify the private landowner(s) and to communicate with them directly to obtain the easements. Landowner information (name and address) for the POI location and the property across the main road should be provided to the Versant Project Manager and ROW Agent as early as possible. Providing this information in a timely manner will streamline the design and permitting process.

12.5 Permitting

A pole permit is required from the authority having jurisdiction whenever a new pole is installed along a public way. Versant Power will obtain the necessary pole permit(s) from the town or State. Versant will coordinate field planning with the local telephone company for joint-use facilities.

12.6 Private Lines

If the POI for a generating facility is interconnecting to or located downstream of privately owned distribution lines, a separate Versant-owned distribution line extension will be required. Based on the location conditions, Versant may pursue the option of a private line buyback, rebuilding to company standards and ownership changes if feasible and warranted. The generating facility will be responsible for all costs incurred. Interconnection site plans submitted to Versant Power must have all final design details. Versant Power reserves the right to select the appropriate site development design.

12.7 Vegetation Management

Typically, Versant Power will trim trees around the POI location to stake and/or set utility poles. It is preferred that the DER Facility Developer completes the clearing of the entire project area.

12.8 Neighboring Landowners & Other Stakeholders

Versant Power will coordinate its activities with neighboring landowners and any other stakeholders involved with the project as necessary. The DER Facility Developer is expected to properly communicate all impacts and activities to stakeholders prior to Versant field planning and construction to avoid any conflicts or project delays. The Developer should communicate any stakeholder concerns to Versant's Project Manager so they can be taken into consideration.

Appendix A – Definitions

The following terms may be used in this Technical Interconnections Requirements document:

Accredited, Nationally Recognized Testing Laboratory (NRTL): A laboratory approved to perform the certification testing required for Generating Facilities equipment.

Active Power: Active or real power to do actual work on a load. Active power is measured in watts (W) and is the power consumed by electrical resistance.

Aggregated Generation: Calculated as of the date of an Interconnection Application, the summation of the following generating projects, in addition to the project proposed by the Applicant, that are or would be interconnected to the Radial Distribution Circuit: (i) all existing generating projects that are in-service; and (ii) all generator projects with a fully executed Interconnection Agreement.

ANSI: American National Standards Institute.

Anti-islanding: A protection system aimed at detecting islanded conditions (see island) and disconnecting the DER Facility from the distribution system if an island forms.

Apparent Power: The power supplied to the electric circuit — typically from a power supplier to the grid — to cover the real and reactive power consumption in the load. Apparent power is measured in volt-amperes (VA) — the AC system voltage multiplied with flowing current.

Applicant: The person or organization applying to interconnect a Generating Facility to the Electric Power System.

Application Review: A review by the Company of the completed Interconnection Application Form to determine if a Feasibility, System Impact and Facility Studies are needed.

Business Day: Monday through Friday, excluding Federal and State Holidays. Calendar Day shall mean any day including Saturday, Sunday, Federal and State Holidays.

Bulk Electric System (BES): As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher.

Closed Transition: A mode of operation in which the DER is operated in parallel with the Versant Distribution System for a brief period of time, to ensure that the load is maintained while transferring from the utility to the DER or vice versa.

Company: Versant Power.

Company DG Facilitator: The Company's designated single point of contact for customer inquiries related to DER Facilities. Interested parties can obtain a copy of the Technical Interconnection Requirements, interconnection applications and any forms that are needed to request an interconnection from the Company DG Facilitator.

Contract Path: A specific contiguous electrical path from a point of receipt to a point of delivery for which Electric Power System rights have been contracted.

Customer: A Person purchasing electricity for the Person's own use, a DER Provider, or a Developer, as context requires.

Delivery Service: The services the Company may provide to deliver capacity or energy produced by the generator to a buyer to a delivery point(s), including related ancillary services.

Demand: The rate at which energy is delivered to or by a system (expressed in kW) at a given instant or average over any designated period of time, typically 15 minutes for Versant revenue metering.

Disconnect: To isolate a circuit or equipment from a source of power.

Disconnect Switch: A mechanical device used for isolating a circuit or equipment from a source of power.

Distributed Energy Resource (DER): A source of electric power that that is not directly connected to a bulk electric system, which includes distributed connected generation and energy storage technologies.

DER Facility: All equipment including DERs, interconnection systems, transformers, protection and coordination systems, sensing devices on the DER Provider's side of the point of common coupling.

DER Provider: A person who owns, operates or is otherwise responsible for a DER Facility that is interconnected to the Versant Distribution System for the purpose of generating electric power.

Direct Transfer Trip (DTT): A remote signal directed from an upstream device to command the interconnection system to disconnect from the distribution system.

Distribution Upgrades: The additions, modifications, and upgrades to the interconnecting T&D Utility's Distribution System at or beyond the utility-owned infrastructure side of the Point of Common Coupling to accommodate interconnection of the Generating Facility. Distribution Upgrades do not include: (1) Interconnection Facilities; or (2) service transformers for single-phase Level 1 Interconnection

Customers and single-phase On-Site-Load Interconnection customers (refer to MPUC Chapter 324 for more details).

Electric Power System (EPS): All electrical wires, equipment, and other facilities owned or provided by the Company that are normally operated at voltages below 115 kV to provide distribution service to customers.

Energy Storage System (ESS): A commercially available technology that uses mechanical, chemical or thermal processes for absorbing energy and storing it for a period of time for use at a later time. A Battery Energy Storage System (BESS) is a subset of ESS.

Facility Study: The study conducted by the Company for Category 3, 4 and 5 Generating Facilities to determine the scope and costs of the required modifications and upgrades to the Company EPS and/or the Generating Facility to provide the requested interconnection service.

Fault: An equipment failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.

Feasibility Study: A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Company's Electric Power System.

Ferroresonance: An oscillatory phenomenon caused by the interaction of system capacitance with the non-linear inductance of a transformer, usually resulting in a high transient or sustained overvoltage.

FERC: Federal Energy Regulatory Commission.

Flicker: The subjective impression of fluctuating luminance caused by voltage fluctuations.

Generator: The owner/operator of the Generating Facility.

Generating Facility: Any device producing electrical energy, i.e., rotating generators, wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc., including energy storage technologies. A system for the generation of electricity located near the point where the electricity will be used or in a location that will support the functioning of the electric power distribution grid.

Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Guidelines: The document prepared by Versant Power to describe the protocols and procedures for interconnecting to the Electric Power System, "Guidelines for Generator Interconnection."

Harmonics: Sinusoidal currents and voltages with frequencies that are integral multiples of the fundamental power line frequency.

IEEE: Institute of Electrical and Electronics Engineers.

Independent System Operator (ISO): An entity supervising the collective transmission facilities of a power region; the ISO is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, and network reliability.

Induction Generator: An induction machine that is driven above its synchronous or zero-slip speed by an external source of mechanical power in order to produce electric power. It does not have a separate excitation system and therefore requires its output terminals to be energized with alternating-current voltage and supplied with reactive power to develop the magnetic flux.

In-Service Date: The date on which the Generating Facility and system modification (if applicable) are complete and ready for service, even if the Generating Facility is not placed in service on or by that date.

Interconnection: The physical connection of a Generating Facility to the Electric Power System so that parallel operation can occur.

Interconnection Agreement (IA): A written agreement between a generator and a T&D Utility which governs the connection of the Generating Facility to the T&D utility's system, as well as the ongoing operation of the Generating Facility after it is connected to the system. An interconnection agreement is required to be signed by the generator and Company before parallel operation of the Generating Facility can commence.

Interconnection Facilities: Facilities and equipment located on the customer-owned infrastructure side of the Point of Common Coupling that are necessary to physically and electrically interconnect the Generating Facility to the T&D Distribution System. Interconnection Facilities do not include: (1) Distribution Upgrades; or (2) service transformers for single-phase Level 1 Interconnection customers and single-phase On-Site-Load Interconnection customers (refer to MPUC Chapter 324 for more details).

Interrupting Device: A device capable of being opened and reclosed whose purpose is to interrupt faults and restore service. These devices can be manual or automatic. Examples include circuit breakers, reclosers, and electronic switches.

IREC: Interstate Renewable Energy Council

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

Islanding: A situation where electrical power remains in a portion of an electrical power system when the Company's transmission or Electric Power System has ceased providing power for whatever reason (emergency conditions, maintenance, etc.). Islanding may be intentional, such as when certain segregated loads in a generator's premises are provided power by a Generating Facility after being isolated from the Company Electric Power System after a power failure.

ISO-NE: The Independent System Operator established in accordance with the NEPOOL Agreement and applicable FERC approvals, which is responsible for managing the bulk power generation and transmission systems in New England, or any successor organization to ISO-New England that is approved by FERC.

Line Section: That section of the Electric Power System between two sectionalizing devices or the end of the distribution line.

Low Voltage Secondary Network Grid System: A Network Secondary Distribution System typically with a nominal voltage of 208Y/120 volts in which the secondaries of distribution transformers are connected to a common network bus through network protectors. Distribution transformers, network protectors and network buses are in multiple locations that are interconnected to form a grid.

Metering Point: The point at which the billing meter is connected (for meters that do not use instrument transformers). For meters that use instrument transformers, the point at which the instrument transformers are connected.

MPUC: Maine Public Utilities Commission.

National Electrical Code: NFPA 70 National Electrical Code is the benchmark for safe electrical design, installation, and inspection to protect people and property from electrical hazards. NEC governs the electrical distribution on the customer side of the utility meter or PCC.

National Electric Safety Code (NESC): The NESC Code covers basic provisions for safeguarding of persons from hazards arising from the installation, operation, or maintenance of conductors and equipment. It also includes work rules for the construction, maintenance, and operation of electric supply and communication lines and equipment. NESC governs the electrical distribution facilities for the utility's EPS.

NEPOOL: New England Power Pool.

NERC: North American Electric Reliability Corporation.

Net Metering: The process, in accordance with applicable Company tariffs, whereby the metered electrical energy production by a Generating Facility is subtracted from the metered Company electrical energy sales to the customer at the Generating Facility.

Network Protector (power and distribution transformers): An assembly comprising a circuit breaker and its complete control equipment for automatically disconnecting a transformer from a secondary network in response to predetermined electrical conditions on the primary feeder or transformer, and for connecting a transformer to a secondary network either through manual control or automatic control responsive to predetermined electrical conditions on the feeder and the secondary network.

Network Secondary Distribution System: A system of alternating current distribution in which the secondaries of the distribution transformers are connected to a common network for supplying light and power directly to consumers' services.

Network Service: Network service consists of two or more primary distribution feeders electrically connected on the secondary (or low voltage) side to form a single power source for one or more customers.

Non-Islanding: Describes the ability of a Generating Facility to avoid unintentional islanding through the operation of its interconnection equipment.

Operating Procedures: The procedures for the operation of both the DER Facility and the Facilities relating to an interconnection, which may be revised from time to time by Versant upon written notice to the DER Provider and attached as a schedule to an Interconnection Agreement.

Overfrequency: The abnormal operating state or system condition that results in a system frequency above the normal 60 Hz.

Overvoltage: The abnormal operating state or system condition that results in a system voltage above the upper limit specified in ANSI C84.1.

Point of Common Coupling (PCC): The point where the Generating Facility-owned electric power system connects to the Company-owned infrastructure, such as the electric power revenue meter, premises service transformer, DG Disconnect switch, or terminals of the Versant primary protective device if applicable.

Point of Delivery: See Contract Path.

Point of Interconnection (POI): The point where the Generating Facility is electrically connected to the Versant EPS.

Point of Receipt: See Contract Path.

Power Factor: The ratio of real or productive power measured in kilowatts (kW) to total or apparent power measured in kVA.

Pre-certified, Pre-certification: A specific generating and protective equipment system or systems that have been certified and documented as meeting applicable test requirements and standards relating to safety and reliability by a nationally recognized testing laboratory or, in the absence of such test requirements and standards, by tests and standards approved by the MPUC.

Primary Service: The electricity service provided to the customer in the service voltage of Versant's Medium Voltage Distribution System (typically >4 kV and <46 kV) at the point-of-common-coupling of the serviced site.

Protection Scheme: Protection functions, including associated sensors, relaying, and power supplies, intended to protect a distribution system or interconnection equipment.

Qualifying Facility (QF): A generation facility that has received certification as a Qualifying Facility from FERC in accordance with the Federal Power Act, as amended by the 1978 Public Utilities Regulatory Policies Act ("PURPA"). The standards for a QF are defined in Title 18, Code of Federal Regulations, Part 292 Subpart A-General Provisions and Subpart B-Qualifying Cogeneration and Small Power Production Facilities.

Reactive Power: The imaginary power in a capacitive or inductive load. It represents an energy exchange between the power source and the reactive loads where no net power is gained or lost. Reactive power is stored in and discharged by inductive motors, transformers, solenoids and capacitors. Reactive power is measured in volt-amperes reactive (VAR).

Recloser: An overcurrent protection device that is used to detect faults on distribution system feeders and has the ability to open and reclose after a specified time, allowing momentary faults to clear.

Ride-through: Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified. ISO-NE defines ride-through requirements for the Versant EPS.

Supervisory Control and Data Acquisition (SCADA): A computing, communications, and visualization architecture used to monitor and control individual pieces of equipment as a system to ensure the system is working properly as a whole.

Scoping Meeting: A scoping meeting is to discuss the interconnection application, review any existing studies relevant to the application, and discuss whether the Company should perform a Feasibility Study or proceed directly to a System Impact Study, or a Facilities Study, or an Interconnection Agreement.

Secondary Service: The electricity service provided to the customer in the service voltage of less than 600 volts at the PCC of the serviced site.

Single Line Diagram (SLD): A single line (phase) representation of a distribution network. Major elements of the network are represented by designated symbols.

Spot Network: A small network typically with a nominal voltage of 480Y/277 volts in which the secondaries of two or more distribution transformers are connected to a common network bus through network protectors usually in a single location.

Switchgear: Components for switching, protecting, monitoring and controlling the Electric Power System.

Synchronous Generator: A synchronous alternating-current machine which transforms mechanical power into electric power. A synchronous machine is one in which the average speed of normal operation is exactly proportional to the frequency of the system to which it is connected.

System Impact Study: An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Company EPS. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting.

Telemetry: The transmission of Generating Facility data using telecommunications techniques.

Three-line Diagram (TLD): A three-phase representation of a distribution network. Major elements of the network are represented by designated symbols. The connections of each of the three phases is indicated between all major equipment elements.

Transfer Switch: A switch designed so that it will disconnect the load from one power source and reconnect it to another source.

UL: Underwriters Laboratories.

Underfrequency: The abnormal operating state or system condition that results in a system frequency below the normal 60 Hz.

Undervoltage: The abnormal operating state or system condition that results in a system voltage below the lower limit specified in ANSI C84.1.

Utility Grade Relay: A relay that is constructed to comply with, as a minimum, the most current version of the following standards: ANSI/IEEE C37.90, ANSI/IEEE C37.90.1, ANSI/IEEE C37.90.2, ANSI/IEEE C37.90.3, IEEE C37.98 Seismic Testing (fragility) of Protective and Auxiliary Relays, ANSI C37.2 Electric Power System Device Function Numbers, IEC 255-21-1 Vibration, IEC 255-22-2 Electrostatic Discharge, and IEC 255-5 Insulation (Impulse Voltage Withstand).

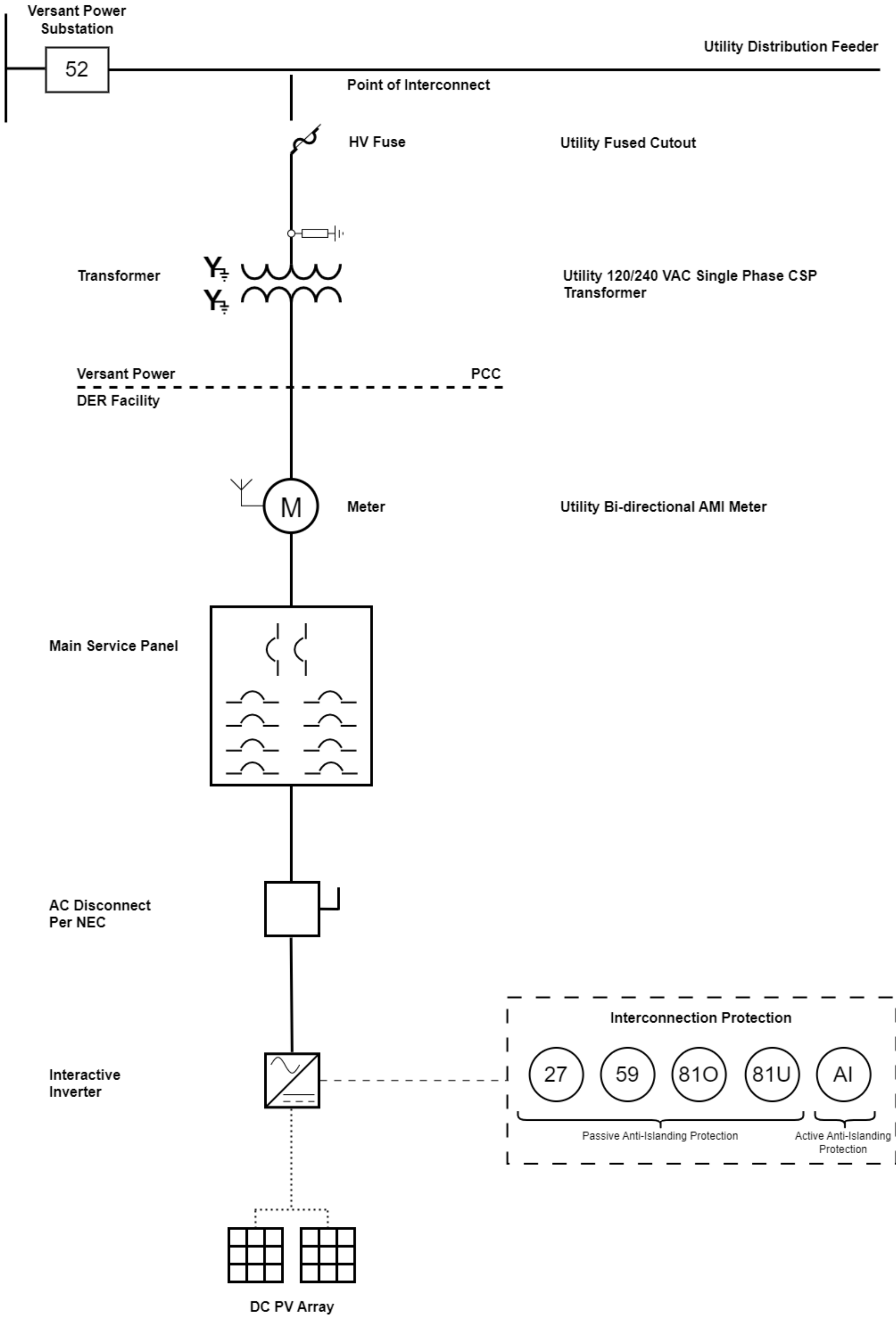
Volt-Ampere Reactive (VAR): A unit by which reactive power is expressed in an AC electric power system.

Voltage Flicker: A condition of fluctuating voltage on a power system that can lead to noticeable fluctuations in the output of lighting systems.

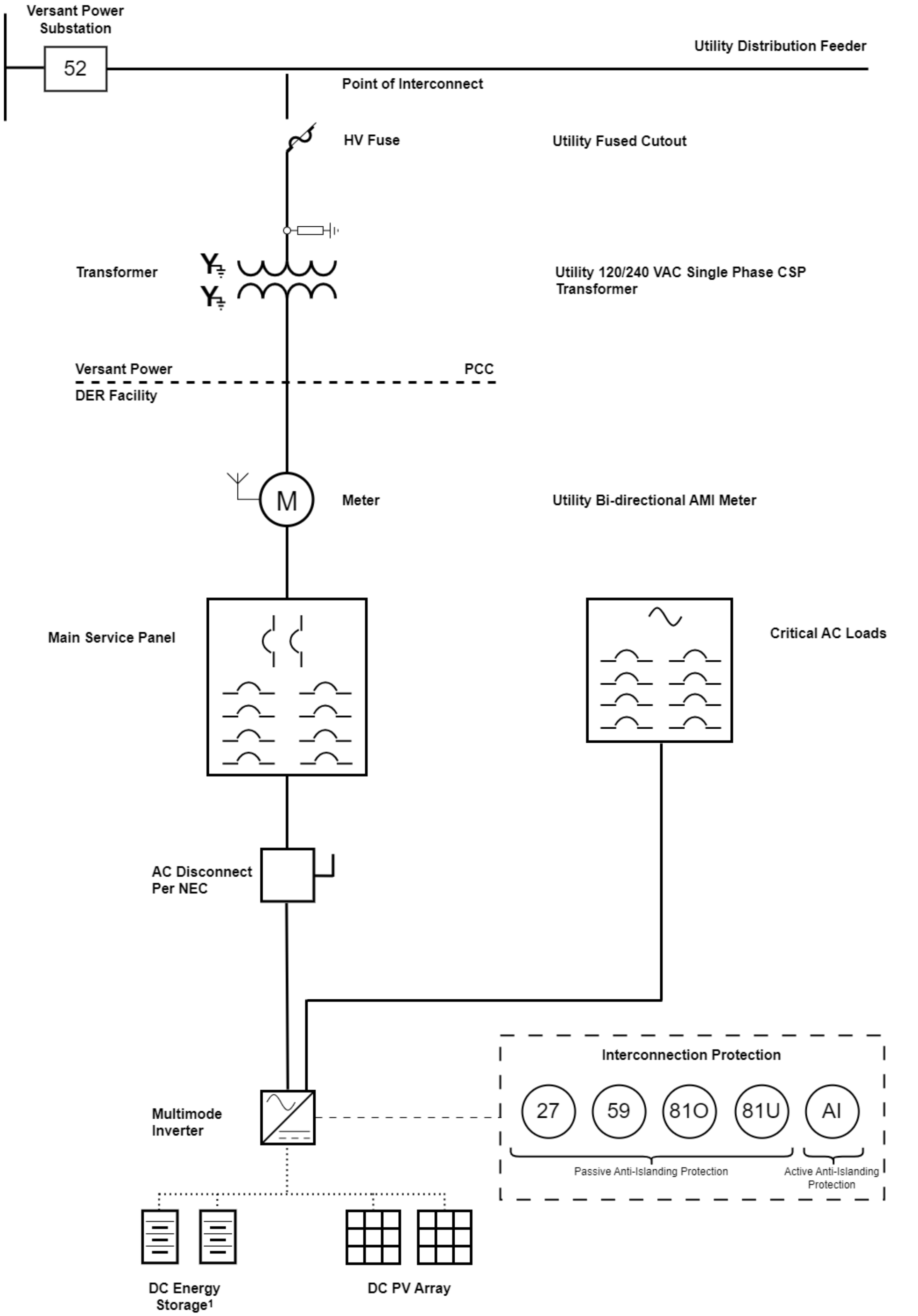
Watt: The scientific unit of real electric power.

Appendix B – Typical Interconnection Diagrams

	General Notes for Interconnection Diagrams
Accessibility	All Versant Power equipment shown on the Interconnection Diagrams shall be accessible at all times
POI	Point of Interconnect is the location where the DER facility is interconnecting to the existing grid i.e. the point where the new Versant owned interconnection facilities are being extended from

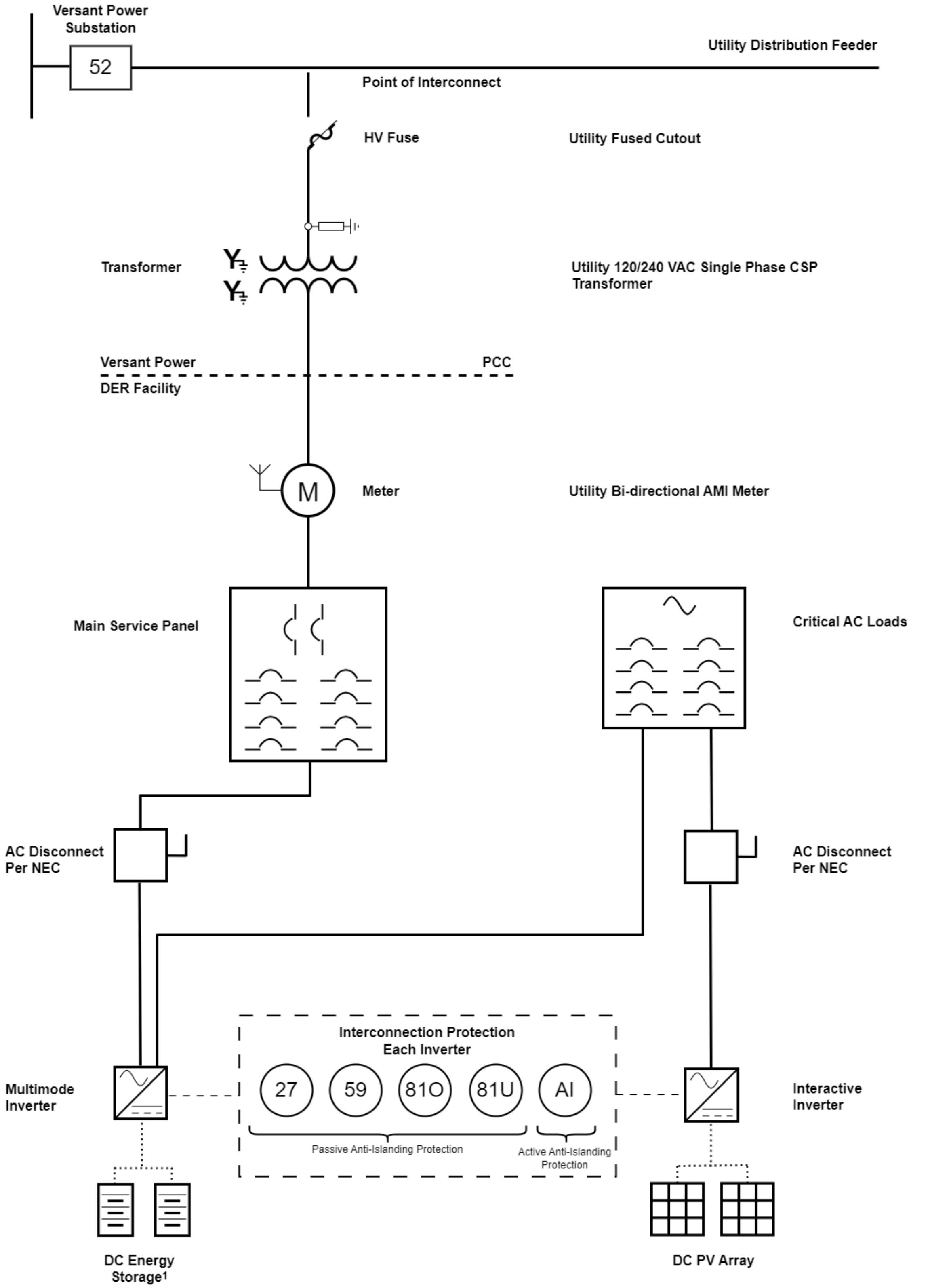


Type 1-1: <25kW Typical Single Phase



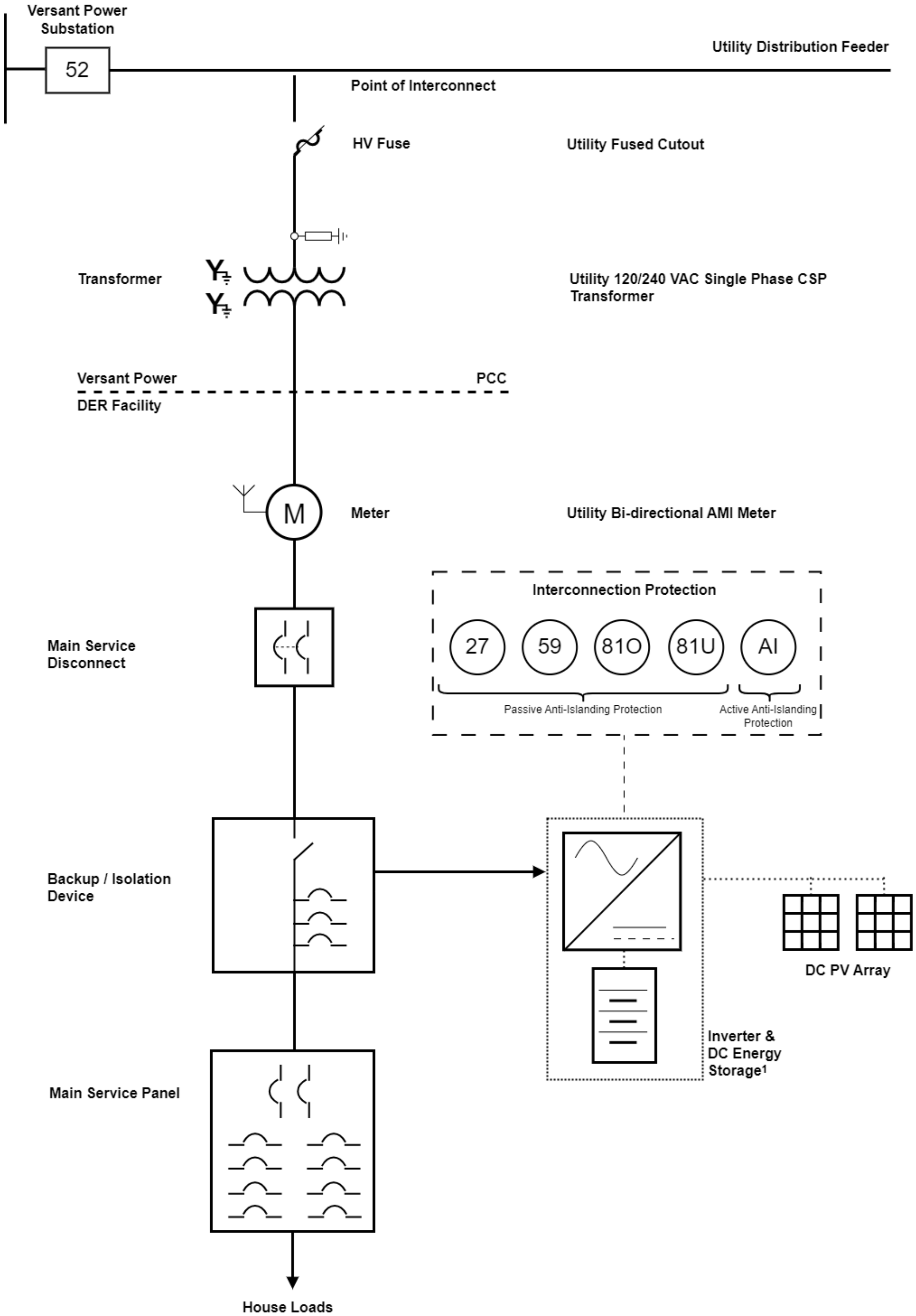
Type 1-2: **<25kW Typical Single Phase DC Coupled PV & Energy Storage**[1]

[1] Interconnection Application will require submittal of an Energy Storage System information form and a complete description of the DER system operation.



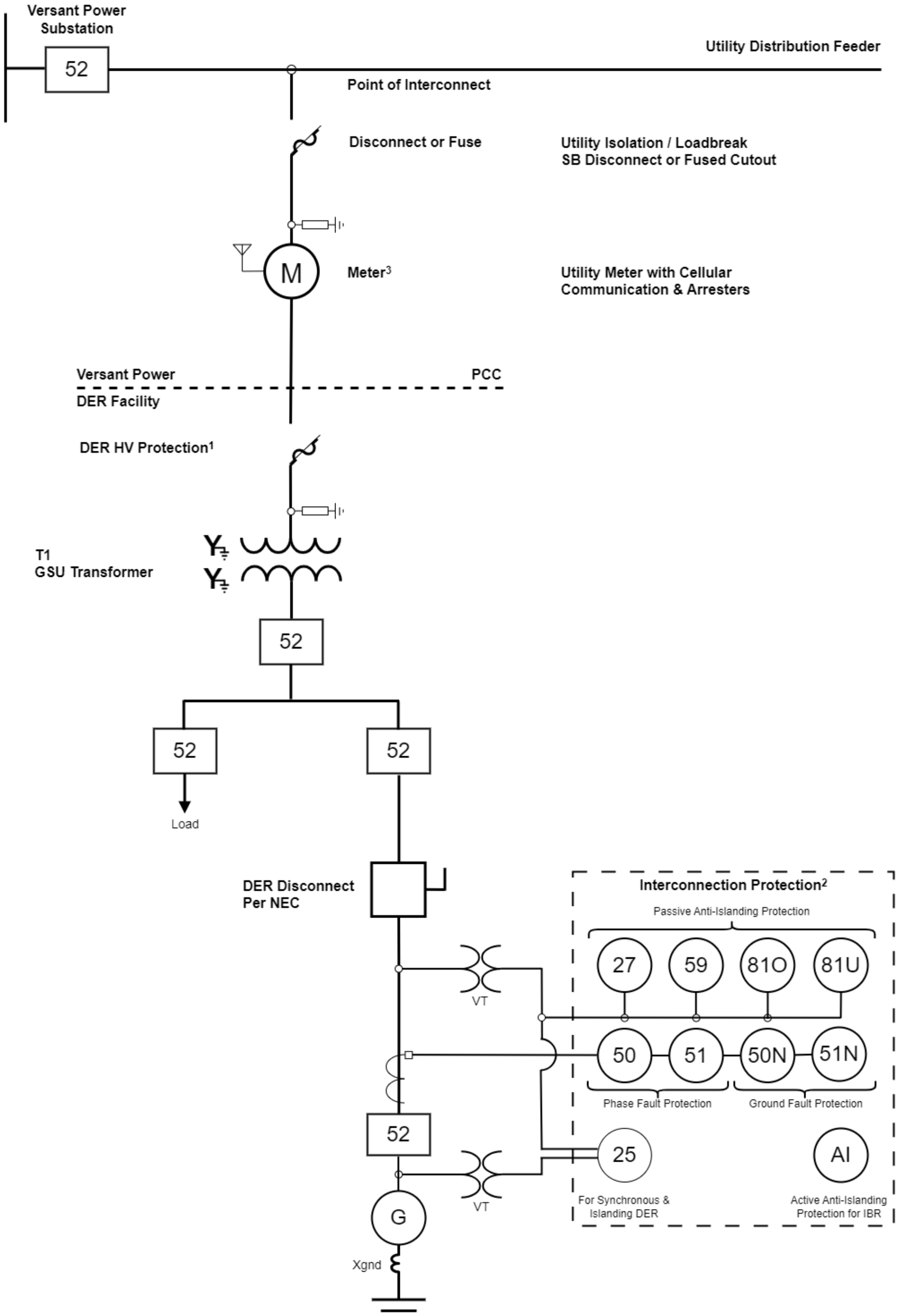
Type 1-3: **<25kW Typical Single Phase**
AC Coupled PV & Energy Storage[1]

[1] Interconnection Application will require submittal of an Energy Storage System information form and a complete description of the DER system operation.



Type 1-4: **<25kW Typical Single Phase Grid Tie/Backup PV & Energy Storage[1]**

[1] Interconnection Application will require submittal of an Energy Storage System information form and a complete description of the DER system operation.

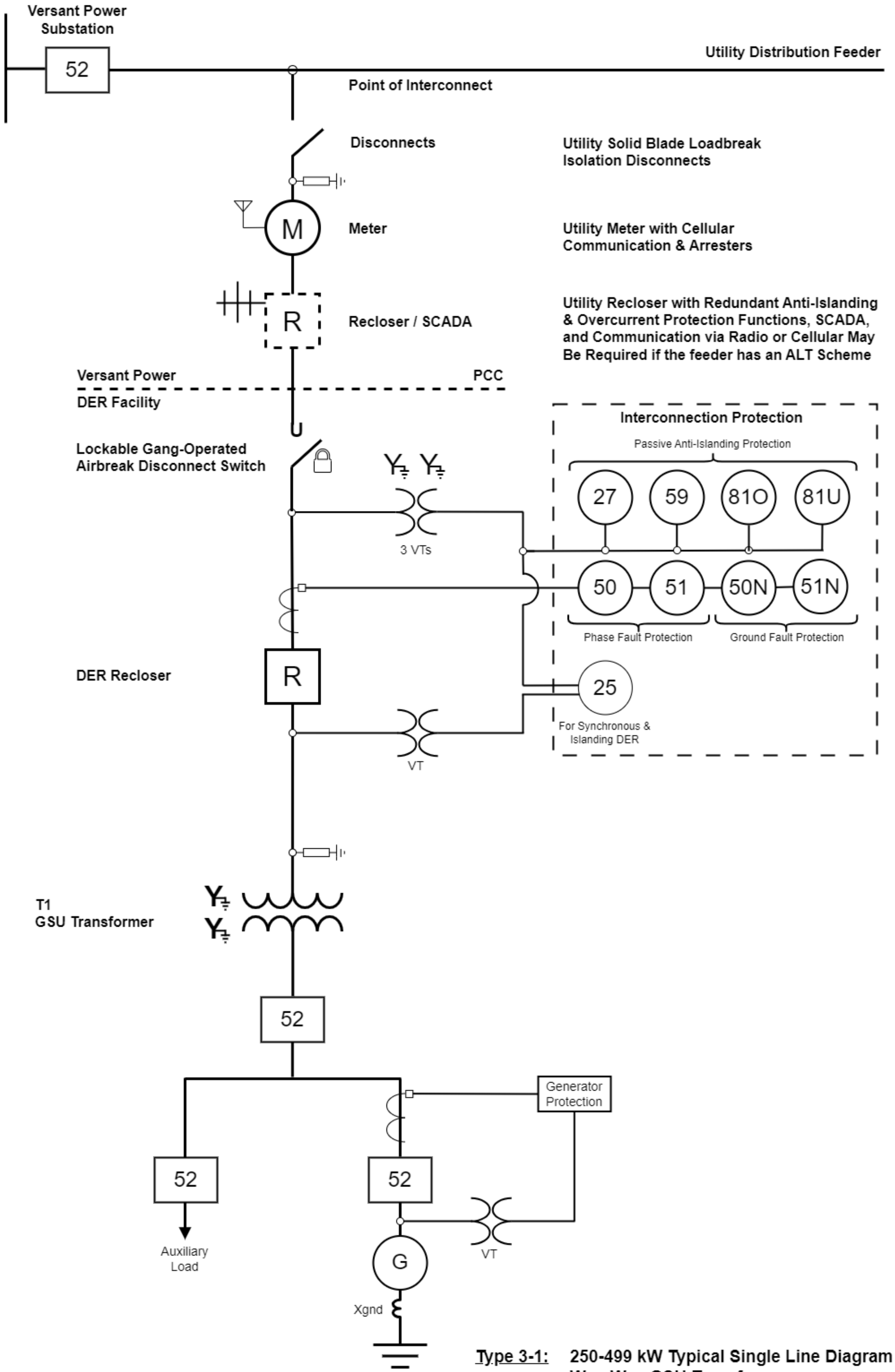


Type 2-1: **25 to 249kW Typical Single Line Diagram Wye-Wye GSU Transformer**

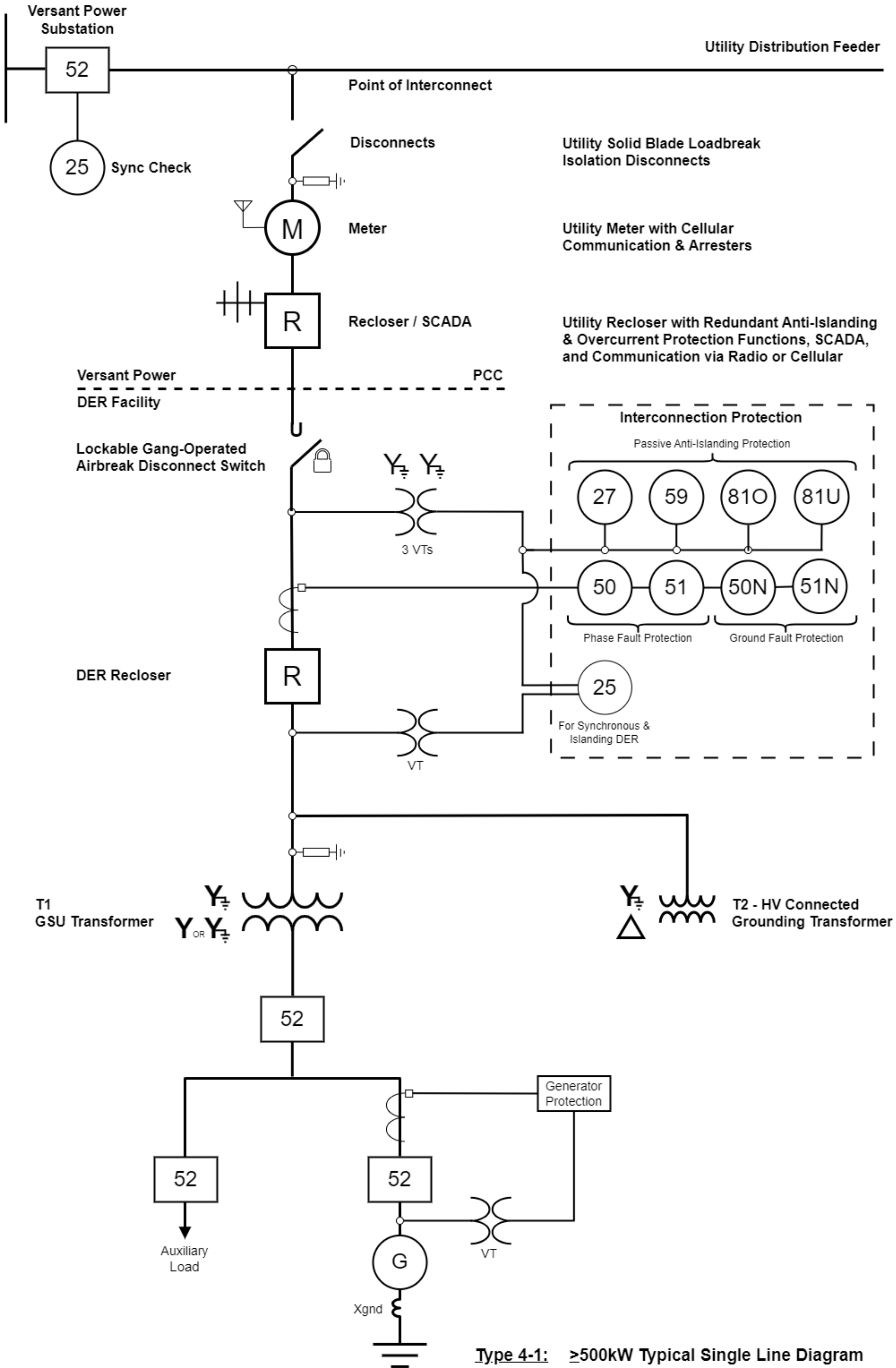
[1] Stand alone DER Facilities shall have a fuse or 3-Phase recloser to provide HV protection for the GSU transformer and HV faults within the DER Facility. N/A for behind the meter DER facilities.

[2] Interconnection protection will be at the HV level if a recloser is installed. Otherwise it will be located with the DER generator.

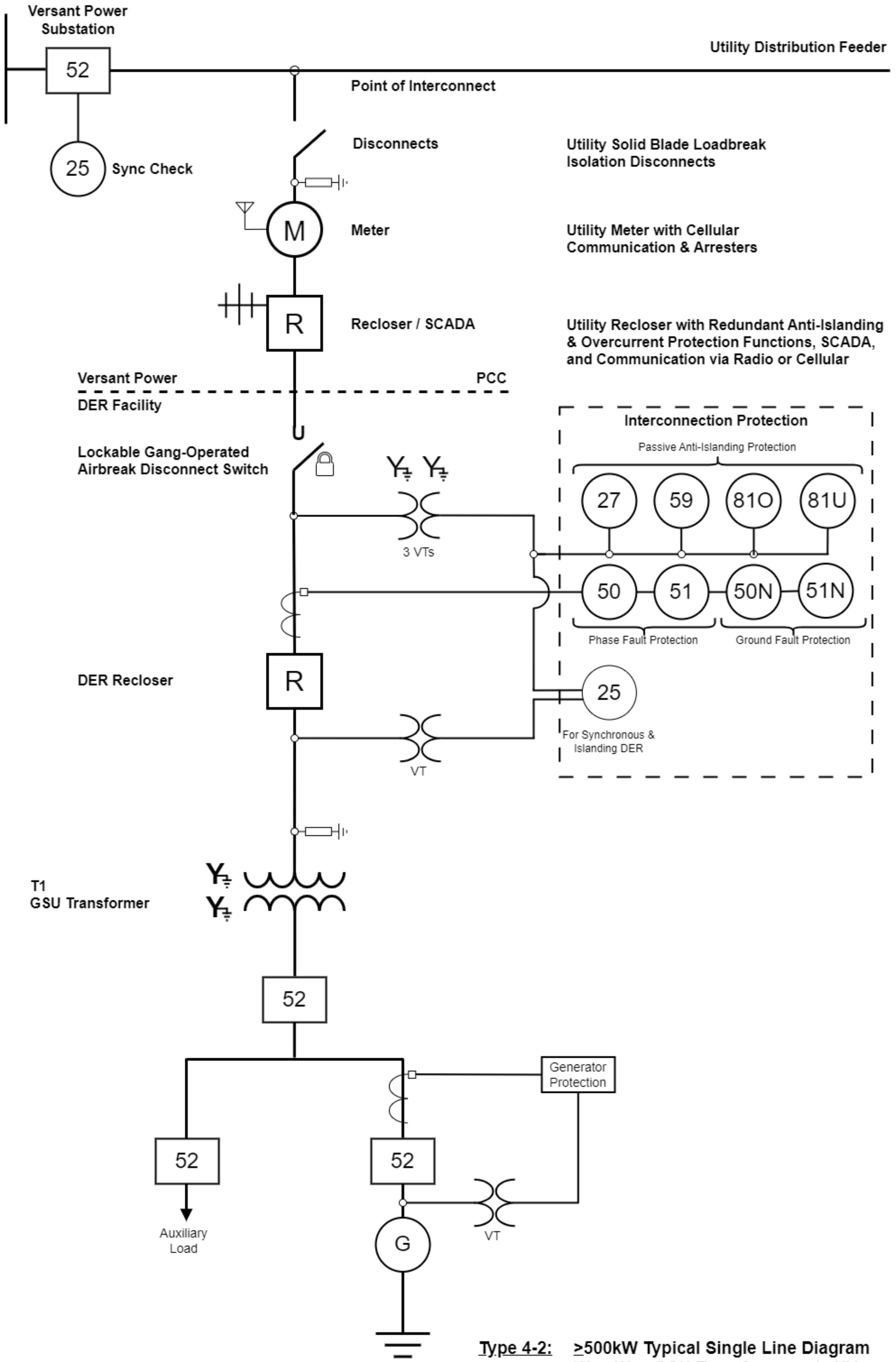
[3] Secondary metering is optional with acceptance of a transformer loss factor applied to billing.



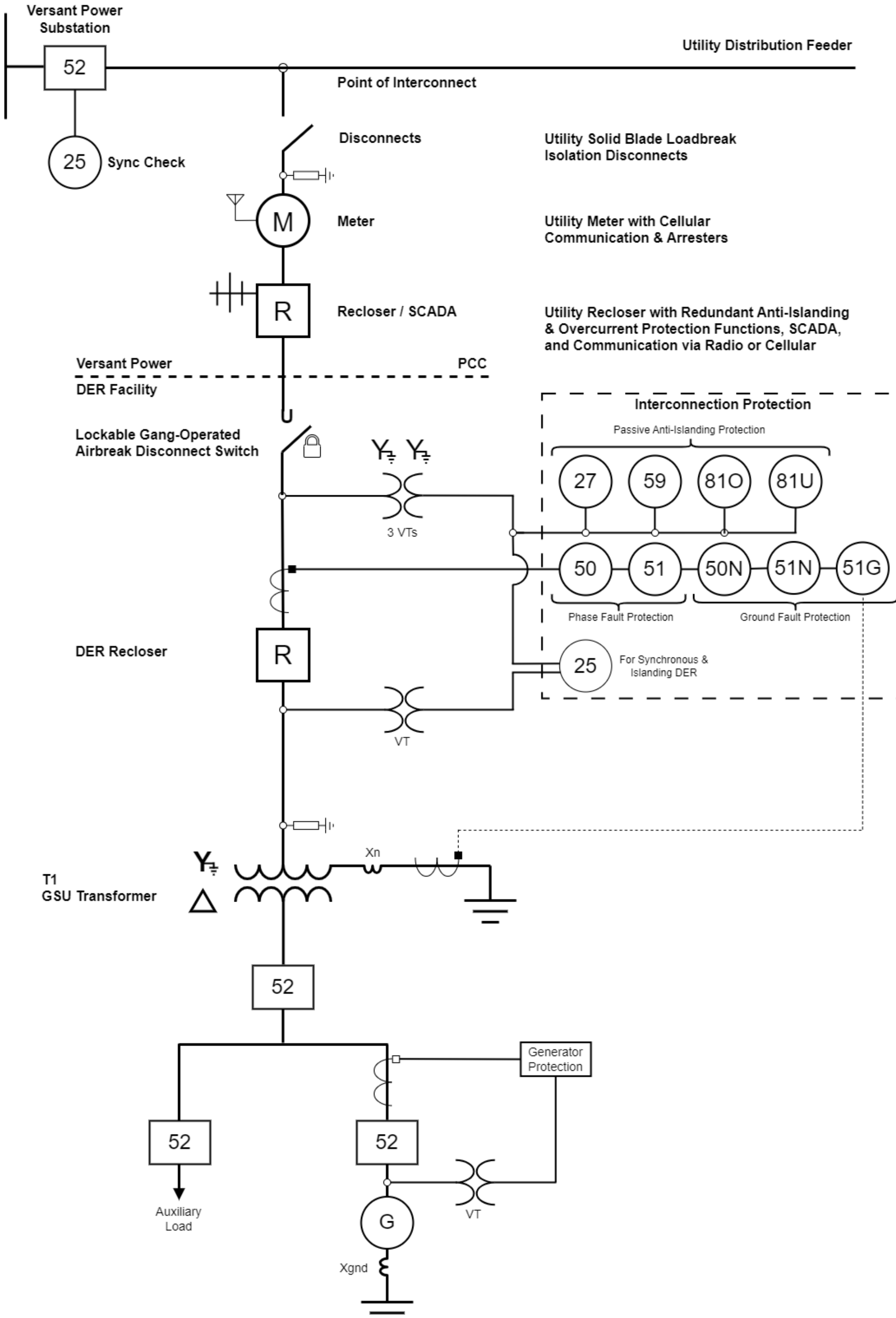
Type 3-1: 250-499 kW Typical Single Line Diagram
Wye-Wye GSU Transformer



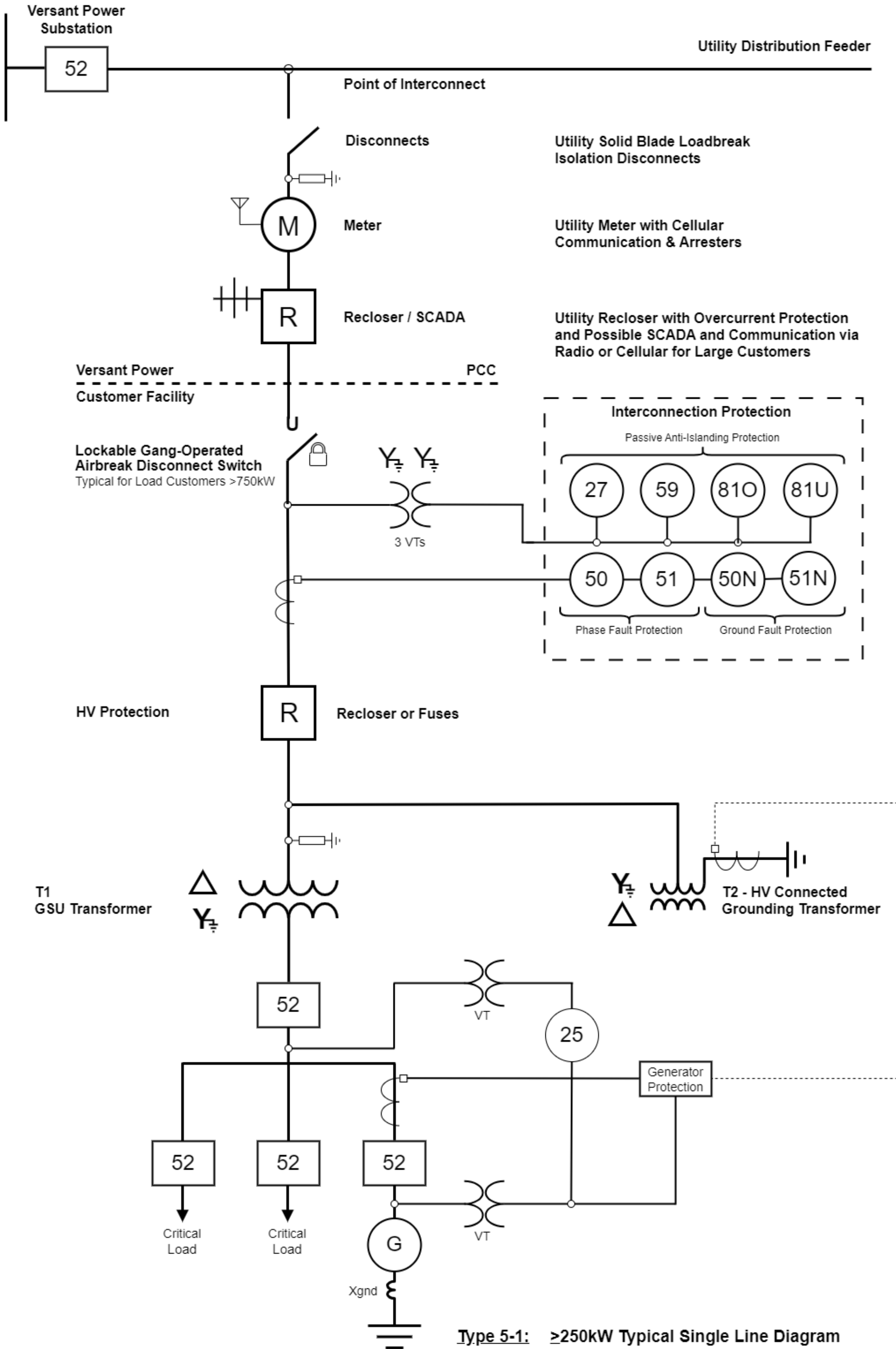
Type 4-1: ≥500kW Typical Single Line Diagram Wye-Wye GSU Transformer with HV Grounding Transformer



Type 4-2: **≥500kW Typical Single Line Diagram**
Wye-Wye GSU Transformer w/o HV
Grounding Transformer
Allowed only when generators are solidly grounded



Type 4-3: ≥500kW Typical Single Line Diagram
Wye-Delta GSU Transformer



Type 5-1: **>250kW Typical Single Line Diagram**
Delta-Wye GSU Transformer with HV Grounding Transformer
Typical when adding co-generation to critical load or industrial facilities that are not effectively grounded

Appendix C – Applicable Codes and Standards

DER interconnection shall comply with the Technical Requirements and applicable sections of the following codes and standards. Specific types of interconnection schemes, DER technologies and the Versant Power Distribution System may have additional requirements, standards, recommended practices or guideline documents external to the Technical Document. The applicability and hierarchy of those, with respect to the requirements herein, are beyond the scope of the Technical Requirements. The list of indicated standards organizations, codes and standards referenced throughout the Technical Document is therefore not to be regarded as all-inclusive. The following documents are subject to revisions from time to time. The latest version of the approved code or standard shall apply.

Standards Organizations:

- IEEE Standards Association (Institute of Electrical and Electronics Engineers)
- ISO-NE (Independent System Operator – New England)
- NESC (National Electrical Safety Code)
- ANSI (American National Standards Institute)
- UL (Underwriters Laboratories)
- NFPA (National Fire Protection Association)
- NEMA (National Electrical Manufacturers Association)
- NERC (North American Electric Reliability Corporation)
- NPCC (Northeast Power Coordinating Council)
- Sandia National Laboratories
- Massachusetts Technical Standards Review Group

Codes and Standards:

- Versant Power Distribution Construction Standards
- Versant Power Electric Service & Metering Standards
- ISO-NE Default IEEE 1547-2018 Setting Requirements
- NESC Electrical & Communication Utility Code
- NEC (NFPA 70) National Electrical Code

- UL 1741-SB Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources with addition of Advanced Inverter Testing Requirements
- IEEE Std 1547 Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
- IEEE Std 1547.1 Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces
- IEEE Std 1547.2 Application Guide for IEEE Standard 1547, Interconnecting Distributed Resources with Electric Power Systems
- IEEE Std 1547.3 Guide for Monitoring, Information Exchange and Control of Distributed Resources Interconnection with Electric Power Systems
- IEEE Std C37.2 Electrical Power System Device Function Numbers, Acronyms, and Contact Designations
- IEEE Std C37.60-2012 Automatic circuit reclosers up to 38kV
- IEEE Std C37.90 Relays and Relay Systems Associated with Electric Power Apparatus
- IEEE Std. C37.90.1 Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus
- IEEE Std C37.90.2 Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.90.3 Electrostatic Discharge Tests for Protective Relays
- IEEE Std C37.98 Seismic Qualification Testing of Protective and Auxiliaries
- IEEE Std C37.108 Guide for the Protection of Network Transformers
- IEEE Std C37.230 Guide for Protective Relay Applications to Distribution Lines
- IEEE Std C57.12.44 Requirements for Secondary Network Protectors
- IEEE Std C57.13 Standard Requirements for Instrument Transformers
- IEEE Std C62.41 Recommended Practice on Surge Voltages in Low Voltage AC Power Circuits
- IEEE Std. C62.41.2 Recommended Practice on Characterization of Surges in Low-Voltage (1000 V and Less) AC Power Circuits
- IEEE Std C62.45 Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits
- IEEE Std C62.92.1 Guide for the Application of Neutral Grounding in Electrical Utility Systems

- IEEE Std 100 The Authoritative Dictionary of IEEE Standards
- IEEE Std 142 Recommended Practice for Grounding of Industrial and Commercial Power Systems
- IEEE Std 519 Harmonic Control in Electrical Power Systems
- IEEE Std 929 Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- IEEE Std 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems
- IEEE Std 1815 – Electric Power Systems Communications-Distributed Network Protocol (DNP3)
- ANSI Std C12.1-2001 American National Standard for Electric Meter Code for Electricity Metering
- ANSI Std C12.11-1993 Instrument Transformers for Metering 15kV and Below
- ANSI Std C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
- IEC 61400 Wind Turbine Generator Systems
- IEC 60255-21 Vibration, shock, bump and seismic tests on measuring relays and protection equipment
- IEC 60255-5 Insulation coordination for measuring relays and protection equipment – Requirements and tests
- NEMA MG1 Motors and Generators
- PRC-006-NPCC-2 Automatic Underfrequency Load Shedding (UFLS) Regional Reliability Standard
- SAND2012-1365 Suggested Guidelines for Assessment of DG Unintentional Islanding Risk
- UL 9540 Standard for Safety for Energy Storage Systems and Equipment

Appendix D - ISO-NE Setting Requirements

Default IEEE 1547-2018 Setting Requirements

Purpose

The purpose of this document is to create a required profile (NE Utility Required Profile) of settings from IEEE 1547-2018 (as amended by IEEE-1547a-2020) to ensure robust and predictable performance of DERs for events on the bulk power system. This can help maintain bulk power system reliability with increasing penetration of DERs. This document was developed by the MA TSRG in conjunction with ISO-NE and supersedes the "Inverter Source Requirement Document of ISO New England."

Applicability

Unless otherwise noted by an individual EDC, all DER applications for facilities with nameplate capacity 500 kW or larger, submitted on or after January 1, 2023, are subject to requirements described in this document and will require documentation of compliance prior to interconnection. In addition, all DER applications for facilities of any nameplate capacity, submitted on or after October 1, 2023, are subject to these requirements and will require documentation of compliance at the time the application is submitted.

All DER projects of all sizes with applications submitted prior to the requirement date are exempt from the requirements listed in this document but are required to meet ride-through requirements listed in the ISO-NE Source Requirement – 2018.

This document states the requirements for all DERs with the following sections:

- Section 1: Requirements that apply to all DERs
- Section 2: Requirements that apply for DERs certified as UL 1741-SB Grid Support Interactive Inverters
- Section 3: Requirements that apply for non-inverter based DERs

The settings presented below are required default settings. Settings for individual facilities may need to be adjusted on a case-by-case basis per the utility requirements.

NOTE: All graphics in this document are used as visualization tools. In the case of any differences between the graphics and the tables, the tables shall supersede the graphics and any discrepancies should be reported to the interconnecting utility and/or the MA TSRG.

Section 1-Requirements common to ALL DER

All applicable DERs:

- Shall be compliant with the latest revision of IEEE-1547-2018 (as amended by IEEE-1547a-2020).
- Shall comply with the required default settings in this document. Different settings are not permitted unless otherwise approved in writing by the interconnecting utility.

1.1 Unintentional islanding for all DERs

Per IEEE 1547- 2018 (as amended by IEEE-1547a-2020) Clause 8.1.1 "For an unintentional island in which the DER energizes a portion of the Area EPS through the PCC, the DER shall detect the island, cease to energize the Area EPS, and trip within 2 s of the formation of an island." No requirements in this document shall be construed as an amendment, alteration or rescindment of this requirement.

1.2 Frequency trip settings for all DERs

Table I: DER response (shall trip) to abnormal frequencies-Category I, Category II and Category III

Shall Trip Function	Required Settings		Comparison to default IEEE td. 1547-2018 for Category I II, III		
	Frequency (Hz)	Clearing Time(s)*	Frequency	Clearing Time (s)	Within Ranges of Allowable settings?
OF 2	62.0	0.16	Identical	Identical	Yes
OF 1	61.2	300.0	Identical	Identical	Yes
UF 1	58.5	300.0	Identical	Identical	Yes
UF 2	56.5	0.16	Identical	Identical	Yes

* ALL DER device trip times shall account for relay/inverter processing times as prescribed by IEEE 1547-2018. In no instance may relay and/or inverter settings trip faster than permitted by IEEE 1547-2018.

1.3 Abnormal frequency performance capability (ride-through) requirements for all DERs

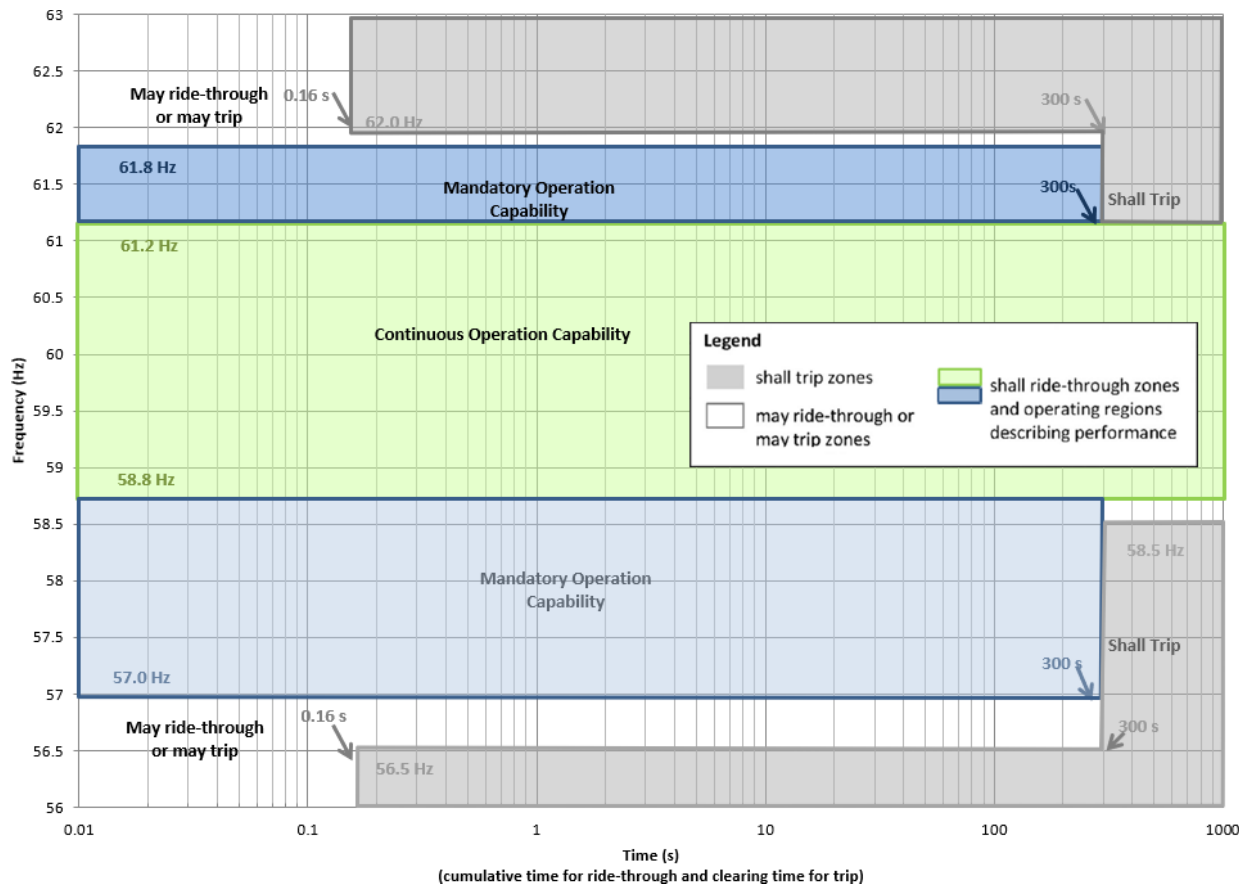
The DER shall have the ride-through capability per abnormal performance Category I, Category II and Category III as specified in IEEE 1547-2018 Section 6.5.2.1. Except when tripping in accordance with the other requirements of IEEE 1547-2018 and this document, the DER must ride through abnormal frequency conditions as required in IEEE 1547-2018. This is shown in Table II and Figure 1 in this document. The DER shall be capable of the entire ride-through region required by the standard if the tripping requirements were to be adjusted or disabled.

NOTE: Per IEEE 1547- 2018, Clause 8.1.1, false detection of an unintentional island that does not actually exist shall not justify non-compliance with ride-through requirements.

Table II: Frequency ride-through requirements for DERs of abnormal operating performance-Category I, Category II, and Category III

Frequency Range (Hz)	Operating Mode	Comparison to IEEE Std. 1547-2018 for Category I, II, III
f > 62.0	No ride-through requirements apply to this range	Identical
61.2 < f ≤ 61.8	Mandatory Operation	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Identical
57.0 ≤ f < 58.8	Mandatory Operation	Identical
f < 57.0	No ride-through requirements apply to this range	Identical

Figure 1: Frequency ride-through and trip requirements for DER of abnormal operating performance-Category I, Category II, and Category III



NOTE: All diagrams are for illustrative purposes only and in no way change the requirements from those stated in the tables in this document and IEEE 1547-2018.

1.4 Grid Support Default Functions Statuses

The functions below required by IEEE 1547-2018 shall comply with the requirements specified in Table III by default.

Table III: Grid support utility interactive inverter default functions status

IEEE 1547-2018 Function	Default Activation State
Constant power factor mode	Unity
Frequency-droop mode (Freq-Watt)	ON[1]
Voltage—reactive power mode (Volt/VAR)	OFF
Active power—reactive power mode (Watt/VAR)	OFF
Constant reactive power mode (Fixed	OFF

VAR)	
Voltage—active power (Volt-Watt) mode	OFF

[1] Per IEEE 1547-2018, frequency-watt is not allowed to be turned off

1.5 Return to service

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting five minutes of healthy utility voltage and frequency in accordance with IEEE 1547-2018 Clause 4.10. The DER shall enter service in accordance with IEEE 1547-2018 Clause 4.10.3, part c. The DER active power output shall increase linearly or in a stepwise linear ramp with a default time of 300 seconds, with steps no greater than 20% of the DER rating. The DER may increase slower than specified, or by other means requested by the DER impact study in accordance with 1547-2018.

Default Enter service delay[2]: 300 seconds

Default Enter service duration: 300 seconds (DER shall ramp according to IEEE 1547 for five minutes by default).

Exception 1: is permitted for all small-scale DERs in accordance with IEEE 1547-2018.

Exception 2: will be evaluated on a case-by-case basis. DERs 500 kVA and larger desiring to use Exception 2 shall send the rationale and request to the utility. An additional 10 business days will be required to be added to all tariff milestones to accommodate utility processing/review as well as ISO review. All requests are subject to utility and ISO acceptance.

1.6 Rate of change of frequency (ROCOF) ride-through requirements

The DER shall ride through as stated in IEEE 1547-2018 Section 6.5.2.5 (Category III or Category I as applicable). The UL 1741 SB certification shall be considered sufficient for individual inverter-based DER devices meeting ride-through requirements for this function.

In addition, no site equipment (e.g., relays, controllers, etc. outside the inverter) is permitted to trip using this function.

The utility reserves the right to verify that protective relay settings and controller settings do not have ROCOF. Note that this will not verify ride-through, nor does it imply that verification is required. No device(s) outside the certified inverter are permitted to enable ROCOF.

1.7 Voltage phase angle change ride-through

All DERs shall meet the minimum voltage phase angle change ride-through requirements in IEEE 1547- 2018 Clause 6.5.2.6. The UL 1741 SB certification shall be considered sufficient for individual inverter-based DER devices meeting ride-through requirements for this function.

In addition, no site equipment (e.g., relays, controllers, etc. outside the inverter) is permitted to trip using this function.

The utility reserves the right to verify that protective relay settings and controller settings do not have Voltage Phase Angle Change trip settings enabled. Note that this will not verify ride through, nor does it imply that verification is required. No device(s) outside the certified inverter are permitted to have Voltage Phase Angle Change trip settings enabled**.**

1.8 General Requirements on Tripping

In accordance with IEEE 1547-2018, DER tripping requirements specified in this document shall take precedence over the abnormal performance capability (ride-through) requirements in this section, subject to the following:

1. Where the prescribed trip duration settings for the respective voltage or frequency magnitude are set at least 160 milliseconds or 1% of the prescribed tripping time, whichever is greater, beyond the prescribed ride-through duration, the DER shall comply with the ride-through requirements specified in this section prior to tripping.
2. In all other cases, the ride-through requirements shall apply until 160 milliseconds or 1% of the prescribed tripping time, whichever is greater, prior to the prescribed tripping time.

Section 2-Requirements for UL 1741 SB certified inverter-based DER

All applicable **inverter-based DERs**:

- Shall be compliant with the latest revision of IEEE 1547-2018
- Shall be certified under UL 1741 SB (Third Edition, Dated September 28, 2021) as a Grid Support Interactive Inverter to IEEE 1547-2018 Category III requirements
- Shall provide documentation verifying certification (e.g., UL 1741 SB certification document)
- Shall comply with the required default settings in this document. Tighter settings are not permitted unless otherwise approved in writing by the interconnecting utility.

2.1 Voltage trip settings

Applicable DER shall have the voltage trip settings specified in Table IV below.

Table IV: Certified inverter response (shall trip) to abnormal voltages - Category III

Shall	Required Settings	Comparison to default IEEE Std. 1547-2018 (as amended by IEEE-1547a-2020) for Category III

Trip Function	Voltage (p.u. of nominal voltage)	Clearing Time(s)*	Voltage	Clearing Time (s)	Within ranges of allowable settings?
OV 2	1.20	0.16	Identical	Identical	Yes
OV 1	1.10	2.0	Identical	Much shorter (default is 13 s)	Yes
UV 1	0.88	3.0	Identical	Much shorter (default is 21 s)	Yes
UV 2	0.50	1.1	Identical	Shorter (default is 2 s)	Yes

* ALL DER device trip times shall account for relay/inverter processing times as prescribed by IEEE 1547-2018. In no instance may relay and/or inverter settings trip faster than permitted by IEEE 1547-2018.

NOTE: No DER is permitted to energize an unintentional island for more than two seconds per IEEE 1547- 2018 Clause 8.1.1 and Clause 1.1 of this document. The settings above do not change that requirement in any way.

2.2 Abnormal voltage performance capability (ride-through) requirements

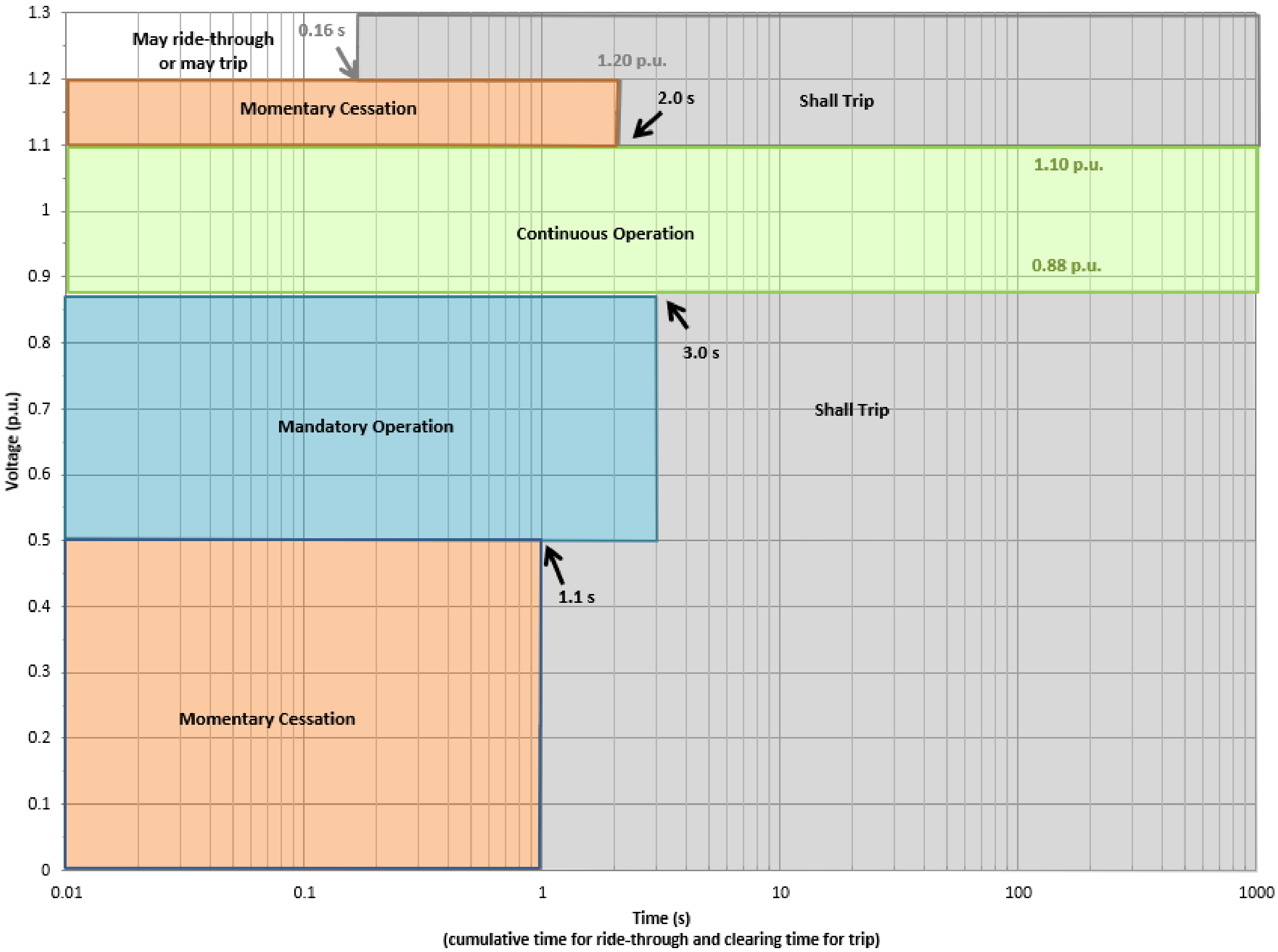
The DER shall have the ride-through capability per abnormal performance Category III of IEEE Std 1547- 2018 Section 6.4.2.1. Except when tripping in accordance with the other requirements of IEEE 1547-2018 and this document, the DER must ride through abnormal voltage conditions as required by IEEE 1547-2018. This is shown in Table V and in Figure 2 in this document. The DER shall be capable of the entire ride-through region required by the standard if the tripping requirements were to be adjusted or disabled.

NOTE: Per IEEE 1547- 2018, Clause 8.1.1, false detection of an unintentional island that does not actually exist shall not justify non-compliance with ride-through requirements.

Table V: Voltage ride-through requirements for certified inverter abnormal operating performance-Category III

Voltage Range (p.u.)	Operating Mode/ Response	Comparison to IEEE Std. 1547-2018 for Category III
V > 1.20	Cease to Energize	Identical
1.10 < V ≤ 1.20	Momentary Cessation	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	Identical
0.5 ≤ V < 0.88	Mandatory Operation	Identical
V < 0.50	Momentary Cessation	Identical

Figure 2: Voltage ride-through and trip requirements for certified Inverter abnormal operating Performance-Category III[3]



NOTE: All diagrams are for illustrative purposes only and in no way change the requirements from those stated in the tables in this document and IEEE 1547-2018.

3 As defined in IEEE 1547:
Mandatory Operation: Required continuance of active current and reactive current exchange of DER with utility's distribution system as prescribed, notwithstanding disturbances of the utility's distribution system voltage or frequency having magnitude and duration severity within defined limits
Momentary Cessation: Temporarily cease to energize the utility's distribution system while connected to the utility's distribution system, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate restore output of operation when the applicable voltages and the system frequency return to within defined ranges
Continuous operation: Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.

2.3 Frequency droop (frequency power) capability

Table VI: Parameters of frequency droop (frequency power) operation of certified Inverter-based DER-Category III

Required Default Settings		Comparison to IEEE Std. 1547-2018 Default Settings for Category III	
Parameter	**Settings**	**Settings**	**Within ranges of allowable settings?**
dbOF, dbUF (Hz)	0.036	Identical	Yes
kOF, kUF	0.05	Identical	Yes
T-response (small-signal) (s)	5	Identical	Yes

Section 3-Settings for non-inverter based DER

All applicable **non-inverter based DERs**:

- Shall be compliant with the latest revision of IEEE 1547-2018
- Shall meet IEEE 1547-2018 Category I requirements
- Shall provide documentation verifying compliance to IEEE 1547-2018 Category I (e.g., UL 1741 SB certification document)
- Shall comply with the required default settings in this document. Tighter settings are not permitted unless otherwise approved in writing by the interconnecting utility.

3.1 Voltage trip settings

Applicable DERs shall have the voltage trip settings specified in Tables VII below.

Table VII: Non- Inverter Based DER response (shall trip) to abnormal voltages – Category I

Shall Trip Function	Required Settings		Comparison to IEEE Std. 1547-2018 for Category I		
	Voltage (p.u. of nominal voltage)	**Clearing Time(s)***	**Voltage**	**Clearing Time (s)**	**Within ranges of allowable settings?**
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Identical	Yes
UV2	0.50	0.16	Slightly higher (default is 0.45 p.u.)	Identical	Yes

* ALL DER device trip times shall account for relay/inverter processing times as prescribed by IEEE 1547-2018. In no instance may relay and/or inverter settings trip faster than permitted by IEEE 1547-2018.

3.2 Abnormal voltage performance capability (ride-through) requirements

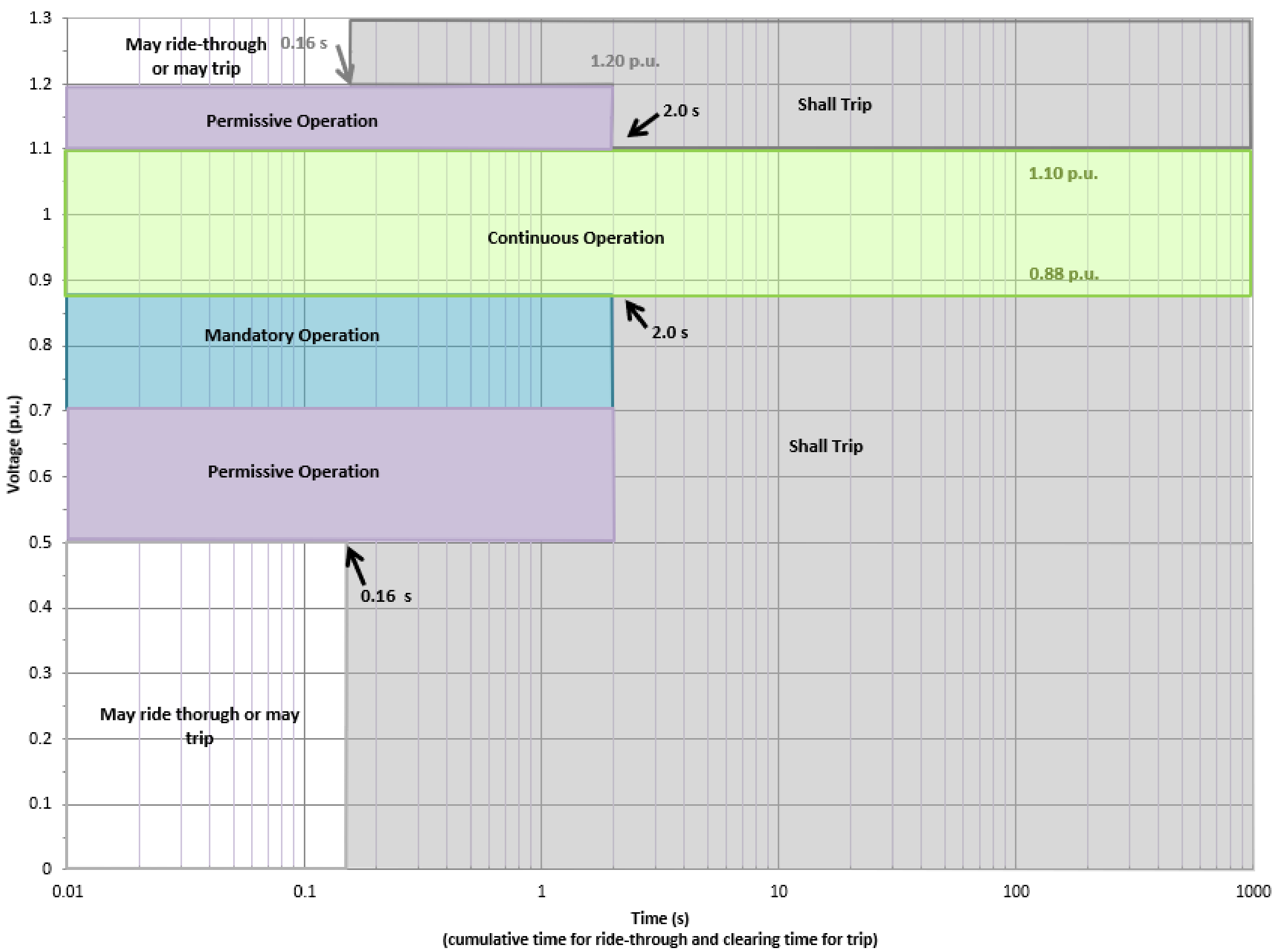
The non-inverter based DER shall have the ride-through capability per abnormal performance Category I of IEEE Std 1547-2018 Section 6.4.2.1. Except when tripping in accordance with the other requirements of IEEE 1547-2018 and this document, the DER shall ride through abnormal voltage conditions as required in IEEE 1547-2018. This is shown in Table VIII and Figure 3 in this document and the DER shall be capable of the entire ride-through region required by the standard if the tripping requirements were to be adjusted or disabled.

NOTE: Per IEEE 1547-2018, Clause 8.1.1, false detection of an unintentional island that does not actually exist shall not justify non-compliance with ride-through requirements.

Table VIII: Voltage ride-through and trip requirements for non-inverter based DER abnormal operating performance-Category I

Voltage Range (p.u.)	Operating Mode/ Response	Comparison to IEEE Std. 1547-2018 for Category I
V > 1.20	Cease to Energize	Identical
1.1 < V ≤ 1.20	Permissive Operation	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	Identical
0.70 ≤ V < 0.88	Mandatory Operation	Identical
0.5 ≤ V < 0.70	Permissive Operation	Identical
V < 0.50	Cease to Energize	Identical

Figure 3: Voltage ride-through and trip requirements for non-inverter based DER abnormal operating



performance - Category I[4]

NOTE: All diagrams are for illustrative purposes only and in no way change the requirements from those stated in the tables in this document and IEEE 1547-2018.

[4]As defined by IEEE 1547-2018: Permissive Operation: Operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the applicable voltages or the system frequency

3.3 Frequency droop (frequency power) capability

Table IX: Parameters of frequency droop (frequency power) default settings for non-inverter based DER-Category I

Required Settings		**Comparison to IEEE Std. 1547-2018 for Category I Default Settings**	
Parameter	**Settings**	**Settings**	**Within ranges of allowable settings?**
dbOF, dbUF (Hz)	1	Much higher (default is 0.036)	Yes
kOF, kUF	0.05	Identical	Yes
T-response (small-signal) (s)	10	Much higher (default is 5)	Yes

Appendix E – Developer Application Checklist

The following Versant Interconnection Application document checklist should be referenced by all DER project developers to identify specific details Versant will confirm are included in Interconnection Application forms, single-line diagrams, site plans and equipment specifications.

By using this checklist, a project developer and their engineers should be able to verify if anything is missing within their documentation before submission. This will save a significant amount of time and resources for both the developer and Versant during initial stages of the interconnection process and will avoid back-and-forth communications as each document iteration is reviewed for conformance. The list includes all items required for each document as well as many common omissions and errors. Versant reserves the right to add or revise these requirements as conditions warrant.

If the checklists are followed, the project scoping meeting can likely be scheduled weeks ahead of what otherwise may occur.

Typical Interconnection Application Documentation Review Process & Pre-Screening

VERSANT DER APPLICATION REVIEW CHECKLIST
FERC Jurisdiction Test → Is the DER connecting to a FERC jurisdictional line? If yes, the ISO-NE SGIP is required and no further application review is necessary. Transmission line interconnections are under FERC jurisdiction. Existing side branches off transmission lines serving distribution customers are considered distribution and not FERC jurisdictional. However, upgrading single phase distribution side branches from transmission lines to three-phase is FERC jurisdictional.
Generator Number Assignment → DG Coordinator will assign a generator asset number to application. Example: G125-1-Bangor EB2. • G125: Next number in sequence of applications received. • 1: One of (8) Line Operations Division Offices. Odd numbers=Bangor Hydro District Even numbers=Maine Public District. 1=Bangor Division • Town: Town where the DER POI is located (Bangor). • EB2: Two-letter Substation identifier (East Bangor) and feeder number. (Feeder No. 2).
Queue Position Assignment Available after developer provides the intention to proceed. DG Interconnections will provide this.
Project Number Assignment Assigned after the scoping meeting and developer provides intention to proceed.
Project Size (AC Nameplate) → Confirm AC nameplate size matches across all project documents. → Confirm project size < 2 MW or MPUC requirements.
POI (Point of Interconnection) → Verify POI pole number with Versant GIS. → Verify POI pole location matches the provided GPS coordinates and Site Plan. → Map project POI in respect to other queued projects on the same circuit.
Circuit ID → If existing double circuit at the POI, confirm circuit and voltage intended for interconnection. → Is the circuit part of an ALT (Automatic Load Transfer) scheme? → Is the circuit part of UFLS (Under Frequency Load Shed) system protection?

→ Confirm circuit nominal voltage.
Substation Capacity → Determine maximum substation transformer base rating. → Determine bus voltage regulator rating. → Determine capacity of existing hydro generation and other connected DERs. → If the source is a stepdown-type substation tapped from subtransmission, a new substation is required.
DEVELOPER INTERCONNECTION APPLICATION
Developer Name → Check if developer name is listed and correct. → Confirm developer name is consistent across all project documents.
Location/Address → Check if location/address is listed and correct. → Confirm location/address is consistent across all project documents. → Verify proposed generation facility address from other references. → Is the generating facility location adjacent to other DERs? Does it meet Chapter 324 requirements? → Make sure provided address, GPS coordinates, POI pole number match the actual location.
Requested In-Service Date → Check if requested in-service date (ISD) is stated. Transmission references this as Commercial Operations Date (COD).
Synchronous/Induction Generator Information (if applicable) → Verify RPM noted in Section 7 and if a neutral grounding resistor is connected to ground the generator. → Verify all machine constants (impedances and reactances) provided in either Section 8 or 9 and match up with the manufacturer's specifications provided separately. → Large synchronous generators should provide excitation details as noted in Section 10.
Inverter Information → Check if inverter information is listed and correct. → Confirm inverter information is consistent across all project documents. Inverter manufacturer Inverter model Inverter rating → Check inverter datasheet if inverter is IEEE1547-2018, IEEE1547.1-2020, UL 1741-SB certified.
PSCAD Model → Check if a PSCAD model was submitted with the application. → Check if PSCAD model information is listed and correct and model has been functionally verified previously.

Project AC Output Rating → Check if AC output rating is listed and correct. → Confirm maximum AC output rating is consistent across all project documents. Nameplate Output Power Rating Maximum DER Facility Physical Export Capability Requested
Inverter AC Output Voltage → Check if inverter AC output voltage is listed. → Confirm inverter AC output voltage is consistent across all project documents. → Confirm inverter AC output voltage matches information listed in the inverter datasheet. → Confirm inverter AC output voltage matches the GSU secondary voltage.
Phase → Check if project is listed as three phase.
ESS Information (if applicable) → Check if project has ESS. • If so, confirm ESS information is listed and correct. • Confirm ESS information is consistent across all project documents. ESS manufacturer ESS model ESS rating • Confirm a ESS datasheet has been submitted.
Rated System Current → Verify rated system current is consistent with Maximum Output Power Rating.
Prime Mover → Verify Prime Mover.
Energy Source → Verify Energy Source.
Equipment List → Verify equipment list. Make sure the listed equipment are correct. Inverter Solar module Primary interrupting device and relay type GSU transformer(s) kVA and winding configuration
THD → Confirm max THD is noted and is < 5%.
GSU Information → Confirm GSU information with Single Line Diagram. → GSU is provided by customer. Confirm kVA is adequate for project AC size. Z% noted. Primary voltage - Secondary voltage. Primary voltage must match circuit voltage.

Secondary voltage must match project AC inverter output voltage. Winding configuration should be one of the following: • grounded wye / grounded wye with grounding transformer • grounded wye / wye with grounding transformer • grounded wye / delta with neutral reactor Versant does not accept primary Delta connected GSUs.	
Project Recloser Information (if listed) → Verify project recloser information with Single Line Diagram.	
Interconnection Application Complete → Confirm the application has all five pages.	
DEVELOPER INVERTER SPECIFICATIONS	
Inverter Information → Confirm inverter information is consistent across all project documents. Inverter manufacturer Inverter model Inverter rating Inverter AC output voltage	
THD → Confirm max THD is noted and is < 5%.	
Inverter Certifications/Compliance → Verify certifications/compliance. • IEEE1547-2018, IEEE1547.1-2020 <u>and</u> UL1741 SB for applications and project inverter changes received after 1/1/2023	
PSCAD Model → Confirm a PSCAD model was submitted with the application. → Confirm PSCAD model is correct for the inverter model and if it is already on file and previously tested.	
DEVELOPER SINGLE LINE DIAGRAM	
Developer Name → Confirm developer name is listed and correct. → Confirm developer name is consistent across all project documents.	
Location/Address → Confirm location/address is listed and correct. → Confirm location/address is consistent across all project documents.	
Project AC Output Rating → Confirm AC output rating is listed and correct. → Confirm maximum AC output rating is consistent with all project documents and is equal to the Maximum DER Facility Physical Export Capability requested.	
ESS Information (if applicable)	

→ Check if project has ESS.
- If so, confirm ESS information is listed and correct.
- Confirm ESS information is consistent across all project documents.
  - ESS manufacturer
  - ESS model
  - ESS rating
- Confirm a ESS datasheet was submitted.
- Is the ESS AC or DC coupled?
  ESS is AC coupled if directly connected to the feeder, not behind the PV inverters.
- Confirm if ESS is charging from the grid that it cannot discharge to the grid.

POI Device Sequence

→ Verify POI device sequence.
Device sequence must be:
POI - Utility Export Revenue Meter - Utility Recloser - PCC - Project GOAB Switch - Project Recloser - Riser Pole - GSU

POI Information

→ Confirm POI pole is shown.
→ Confirm POI information is listed and correct.
- Versant Circuit ID
- Versant Distribution circuit voltage
- Versant pole number

→ If GPS coordinates are listed, verify they are correct.

Utility Export Revenue Meter

→ Confirm utility meter pole is shown.
→ Confirm utility meter pole placement is correct.

Utility Recloser

→ Utility recloser is required for projects $\geq$ 500 kW.
→ Confirm utility recloser pole is shown.
→ Confirm utility recloser pole placement is correct.

PCC

→ PCC is the line indicating ownership between utility-owned and customer-owned equipment.

Project DG (GOAB) Switch (Gang-Operated Airbreak Switch)

→ Confirm project GOAB switch pole is shown.
→ Confirm project GOAB switch pole placement is correct.
→ Project GOAB switch must be listed as accessible and lockable by Utility at all times. SLD must show a note indicating this requirement.

Project Recloser

→ Confirm project recloser pole is shown.

Project recloser is required for projects ≥ 250 kW. Project recloser is required for string inverters ≥ 250 kW and central inverters ≥ 500 kW. → Confirm project recloser pole placement is correct. Project recloser must be placed immediately right after project GOAB switch pole. Line protection (project recloser) must be placed at the beginning of the line and closer to the PCC. → Confirm project recloser and control manufacturer, model, ratings, and settings are listed. SLD must show primary protection (project recloser) settings. Project recloser settings are needed for SIS. See example. → Voltage measurement accuracy cannot exceed +/-1%. SLD must show a note indicating this requirement. → Confirm Section 7.4 requirements are or can be met if the PCC recloser is a padmounted device fed from primary underground. Note these additional requirements in the screening report.
Grounding Transformer → Grounding transformer may or may not be shown. SIS will determine if the project requires a grounding transformer based on effective grounding criteria and GFOV. → If a grounding transformer is shown, confirm primary or secondary connected, type, winding configuration, kVA rating, %Z impedance, X/R ratio and voltages are listed. Ratings will confirmed or revised in the SIS. → Confirm method of interlocking grounding transformer operation with project energization.
GSU Transformer → Confirm GSU(s) are shown. → Verify GSU information. Confirm consistent with the Interconnection Application. kVA rating is adequate for project AC size. %Z. X/R ratio. Primary voltage - Secondary voltage. Primary voltage must match circuit voltage. Secondary voltage must match project AC output voltage. Winding configuration should be one of the following: • grounded wye / grounded wye with grounding transformer • grounded wye / wye with grounding transformer • grounded wye / delta with neutral reactor. Delta without neutral reactor negatively impacts the Versant Power protection and control scheme Versant does not accept primary Delta configuration.

Arresters

→ Verify arresters are shown.
→ Arresters should be intermediate class.
→ Confirm all project arresters protecting all DG equipment are rated according to Versant's distribution voltage:

Versant Power Distribution System Surge Arrester Ratings		
System Voltage (kV rms)	Arrester MCOV (kV rms)	Duty Cycle Rating (kV rms)
7.2 / 12.47	7.65	9
7.62 / 13.2	8.4	10
19.9 / 34.5	22	27

Inverter Information

→ Confirm inverter information is listed and correct.
→ Confirm inverter information is consistent across all project documents.
  Inverter manufacturer
  Inverter model
  Inverter rating
  Quantity
→ Confirm inverter settings are listed. See example.
→ Verify the number of inverters x ratings = the project size.

Secondary Breaker

→ Confirm secondary breaker is shown and breaker rating.

Cable/Wire Schedule

→ Confirm a cable/wire schedule is shown.
→ Confirm cable/wire schedule has sufficient & complete information.
  Cable/Wire schedule must show point-to-point detail of conductors from the PCC to the GSU.
  Conductor types, lengths, and impedances.

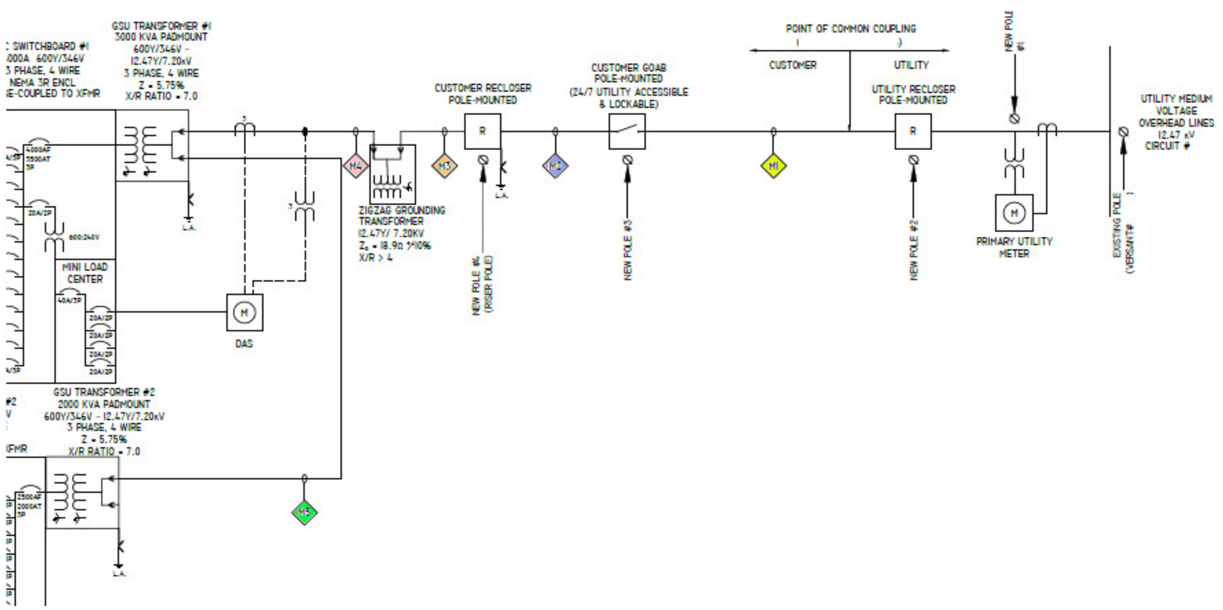
Versant does not allow UG line from POI to project recloser. Cables from POI to project recloser must be overhead. See examples below.

Cable/Wire schedule example 1:

AC Wire and Cable Schedule															
From	To	Cable Number	Type	Material	Conductor	Voltage (kV)	Feet	Overhead - Ohms/mile Underground - Ohms/1000ft				Per Unit Value (100 MVA Base)			
								R_1	X_1	R_0	X_0	R_1	X_1	R_0	X_0
PCC	GOAB	C3	Overhead	ACSR	336.4	12.47	250	0.3268	0.807201	0.613	2.625215	0.009951	0.024578	0.018665	0.079935
GOAB	Recloser	C4	Overhead	ACSR	336.4	12.47	250	0.3268	0.807201	0.613	2.625215	0.009951	0.024578	0.018665	0.079935
Recloser	Riser	C4	Overhead	ACSR	336.4	12.47	3980	0.3268	0.807201	0.613	2.625215	0.158416	0.391289	0.297151	1.272568
Riser	Grounding Xfmr	C6	Underground	AL	500	12.47	175	0.045	0.0355	0.0715	0.0904	0.005064	0.003995	0.008047	0.010174
Grounding Xfmr	Equip Pad #1	C5	Underground	AL	500	12.47	10	0.045	0.0355	0.0715	0.0904	0.000289	0.000228	0.00046	0.000581
Equip Pad #1	Equip Pad #2	C6	Underground	AL	4/0	12.47	685	0.105	0.041	0.1669	0.1044	0.046254	0.018061	0.073521	0.045989
Equip Pad #2	Equip Pad #3	C7	Underground	AL	4/0	12.47	600	0.105	0.041	0.1669	0.1044	0.040514	0.01582	0.064398	0.040283

Cable/Wire schedule example 2:

MEDIUM VOLTAGE AC WIRE SCHEDULE								OVERHEAD- OHMS/MILE UNDERGROUND-OHMS/ 1000 FEET				PER UNIT VALUES (100MVA BASE)			
TAG	TO / FROM	CONDUCTORS	WIRE TYPE	WIRE INSTALLATION LOCATION	VOLTAGE RATING	CONDUIT SIZE	DISTANCE (FT)	R1	X1	R0	X0	R1	X1	R0	X0
M1	UTILITY OWNED RECLOSER / CUSTOMER OWNED GOAB	(4) 4/0 PENGUIN	ACSR	OVERHEAD	15kV	NA	30	0.514	0.717	0.799	3.205	0.0019	0.0026	0.0029	0.0117
M2	CUSTOMER OWNED GOAB / CUSTOMER RECLOSER (PRIMARY RISER)	(4) 4/0 PENGUIN	ACSR	OVERHEAD	15kV	NA	30	0.514	0.717	0.799	3.205	0.0019	0.0026	0.0029	0.0117
M3	CUSTOMER RECLOSER (PRIMARY RISER) / GROUNDING XFMR	(3) 500 KCMIL IC AL W CONC NEUTRAL	MV-90	UNDERGROUND	15kV	5" PVC-80	340	0.047	0.040	0.094	0.079	0.0103	0.0087	0.0205	0.0173
M4	GROUNDING XFMR /GSU #1	(3) 500 KCMIL IC AL W CONC NEUTRAL	MV-90	UNDERGROUND	15kV	4" PVC-80	10	0.047	0.040	0.094	0.079	0.0003	0.0003	0.0006	0.0005
M5	GSU #1 / GSU #2	(3) 500 KCMIL IC AL W CONC NEUTRAL	MV-90	UNDERGROUND	15kV	5" PVC-80	375	0.047	0.040	0.094	0.079	0.0113	0.0096	0.0226	0.0191



Primary protection (recloser) settings example:

PROTECTIVE RELAY SETTINGS					
INVERTER PROTECTIVE FUNCTIONS	TRIP OUTPUT	VOLTAGE SETTING (SEC) PRI (PU)	FREQUENCY SETTING (HZ)	TOTAL CLEARING TIME CYC. (SEC.)	CURRENT SETTING SEC (PRI)
27P1 - FAST UNDERVOLTAGE	X	(60) 3600 (50%)	-	66 (1.1)	-
27P2 - UNDERVOLTAGE	X	(106) 6335 (88%)	-	120 (2)	-
59P1 - OVERVOLTAGE	X	(132) 7919 (110%)	-	120 (2)	-
59P2 - FAST OVERVOLTAGE	X	(144) 8640 (120%)	-	9.6 (0.16)	-
81UP1 - UNDERFREQUENCY	X	-	56.5	9.6 (0.16)	-
81UP2 - UNDERFREQUENCY	X	-	58.5	18000 (300)	-
81OP1 - OVERFREQUENCY	X	-	61.2	18000 (300)	-
81OP2 - OVERFREQUENCY	X	-	62	9.6 (0.16)	-
51 - OVERCURRENT	X	-	-	CURVE: U4 T.M:2	0.48 (288)
51 G - GROUND OVERCURRENT	X	-	-	CURVE: U4 T.M:2.4	0.20 (120)
79 - RECLOSER	X	95%≤ V≤ 105%	59.5Hz≤ f≤ 60.5Hz	5 MINUTES	SEE NOTE 13 & 14
ALARM	X	-	-	<120	SEE NOTE 15

* ALL TRIP TIMES ARE INCLUSIVE OF RECLOSER OPENING (~3 CYCS.).

Inverter settings example:

PROPOSED UL1741 INVERTER INTERNAL CONTROL SETTINGS					
DEVICE	PICKUP		CLEARING TIME		
27-1	50%	(315 V)	66	CYC	(1.1 SEC)
27-2	88%	(554.4 V)	120	CYC	(2 SEC)
59-1	110%	(693 V)	120	CYC	(2 SEC)
59-2	120%	(756 V)	9.6	CYC	(0.16 SEC)
81U-1	58.5 HZ		18000	CYC	(300 SEC)
81U-2	56.5 HZ		9.6	CYC	(0.16 SEC)
81O-1	61.2 HZ		18000	CYC	(300 SEC)
81O-2	62 HZ		9.6	CYC	(0.16 SEC)

Base Voltage 630 V.

PF = 1.0

DEVELOPER SITE PLAN
Developer Name → Confirm developer name is listed and correct. → Confirm developer name is consistent across all project documents.
Location/Address → Confirm location/address is listed and correct. → Confirm location/address is consistent across all project documents.
Project AC Output Rating → Confirm AC output rating is listed and correct. → Confirm AC output rating is consistent across all project documents.
ESS Information (if applicable) → Confirm project has ESS. • If so, confirm ESS information is listed and correct. • Confirm ESS information is consistent across all project documents. ESS manufacturer ESS model ESS rating • Verify ESS location is correct.
Layout → Confirm feasibility of the overall project layout in the Site Plan. → Confirm street name is correct. → Confirm POI location and project site match provided address, GPS coordinates, POI pole number. → Project equipment and access must not enter utility's right of way. (Versant right-of-way crossings of private facilities require approval before applying). → Confirm there is driveway access to utility-owned poles with a 10-by-20-foot turnaround near project GOAB switch shown. → One POI can only serve one project. → Pole spacing from POI to Project Recloser needs to be 30 to 75 feet between poles and in sight of each other. Primary protection needs to be located as close as possible to the beginning of the PCC. VP has to be able to see the POI poles from each during switching. The PCC switch, VP metering, and VP recloser poles should all be in visual sight line of each other. → Poles should be a minimum of five feet and maximum of 15 feet from the edge of the project access driveway.
POI Device Sequence → Verify device sequence. Device sequence must be: POI - Utility Export Revenue Meter - Utility Recloser - PCC - Project GOAB Switch - Project Recloser - Riser Pole - GSU
POI Pole → Confirm POI pole is shown.

→ Confirm POI information is listed and correct. Versant Circuit ID Versant circuit voltage Versant pole number → If GPS coordinates are listed, check if they are correct.
Utility Export Revenue Meter → Confirm utility meter pole is shown. → Confirm utility meter pole placement is correct.
Utility Recloser → Confirm utility recloser pole is shown. → Confirm utility recloser pole placement is correct.
Project GOAB Switch → Confirm project GOAB switch pole is shown. → Confirm project GOAB switch pole placement is correct. → Project GOAB switch must be listed as accessible and lockable by utility at all times. Site Plan must show a note indicating this requirement.
Project Recloser → Confirm project recloser pole is shown. → Confirm project recloser pole placement is correct. → Confirm installation requirements of Section 7.2 Interrupting Device are met if the PCC interrupting device is padmounted and fed from primary underground cable.
GSU → Confirm GSU transformer(s) placement is shown. → Verify number of GSU transformers is consistent with the SLD.
Inverter Information → Confirm inverter information is listed and correct. → Confirm inverter information is consistent across all project documents. Inverter manufacturer Inverter model Inverter rating Quantity

Appendix F – Design Change Impacts

DER Design Change Impacts to Study Results

This section describes how design changes to a DER project can affect the results of a system impact study. Significant changes after a System Impact Study (SIS) has been completed will likely lead to requirement of a restudy and possible reassignment of queue position, among other impacts. By guiding the reader through decision considerations, prudent specification of replacement equipment may avoid additional SIS analyses, helping both project developers and Versant efficiently consider replacements (time and cost) while accommodating the market realities and business constraints driving these changes. Changes to inverters, generator step-up (GSU) transformers, and grounding banks are covered.

1 Background

Changing equipment for a DER project once the SIS has been completed can result in additional study expenses, project delays, and loss of queue position. To avoid these potentially unnecessary issues, the specifications of the replacement equipment must be carefully considered with respect to the originally studied equipment. Although a restudy may be warranted for some equipment changes, it could be avoided in cases with the prudent application of the considerations discussed here.

Other factors influencing the need for restudy include the status of the SIS, whether the project was to operate at unity power factor, and whether a Time Domain Study (TDS) was undertaken.

1.2 Elements of a Standard Study

Table 6 below shows the elements of steady-state studies performed chronologically to ensure a safe and reliable DER interconnection. This section will discuss elements impacted by specific changes in DER project design.

Table 6: Elements of a Standard Study

Study Element	Purpose	Reference
Design Review	Ensures compliance with utility standards and requirements.	Utility Interconnection Standards
Substation Transformer Loading Evaluation	Ensures the substation transformer is not overloaded under any scenario.	Equipment ratings
Thermal Analysis	Avoids overloading grid components beyond established ratings under normal (N-0) system conditions.	Equipment ratings

Study Element	Purpose	Reference
N-1 Analysis	Avoids overloading grid components beyond established ratings under loss of single element (N-1) system conditions.	Equipment ratings
Voltage Analysis	Ensures steady-state voltages remain within established criteria.	ANSI C84.1
Reactive Analysis	Evaluates the impact on system load power factor.	ISO-NE OP-17
Output Drop Analysis	Avoids impression of fluctuating luminance caused by voltage changes over a period, as well as undue voltage regulating equipment.	IEEE 1453-2015

1.3 Elements of a Protection Coordination Study (PCS)

Table 7 below shows the elements of protection studies performed chronologically to ensure a safe and reliable DER interconnection. This section will discuss elements impacted by specific changes in DER project design.

Table 7: Elements of a Protection Coordination Study

Study Element	Purpose	Reference
Fuse Savings	Ensures that fuse savings schemes removed by the project are either restored or additional upgrades are implemented to maintain reliability.	Utility Interconnection Standards
Effective Grounding Analysis	Ensures the utility distribution circuit remains effectively grounded in any configuration to limit unfaulted phase voltages to less than or equal to 138% of nominal phase voltage during unbalanced fault conditions. IEEE C62.92.1 defines Effectively Grounded systems as those with a COG <80%. Furthermore, Versant mandates an effective grounding criteria of X0/X1<3 and 0<R0/X1<1.	IEEE 142-2007 IEEE C62.92.1
Device Rating Evaluation	Checks interrupting rating and continuous operating rating criteria to account for load and DER growth, contingency operating conditions, and cold-load inrush currents.	IEEE C37.230-2020
Device Setting Evaluation	Checks pickup margin and protective reach criteria to account for load and DER growth, contingency operating conditions, and cold-load inrush currents.	IEEE C37.230-2020

Study Element	Purpose	Reference
Device Coordination Evaluation	Checks protection coordination margins to ensure all protective devices are properly coordinated and perform with the correct sequence of operations.	Utility Interconnection Standards

1.4 Elements of a Time Domain Study (TDS)

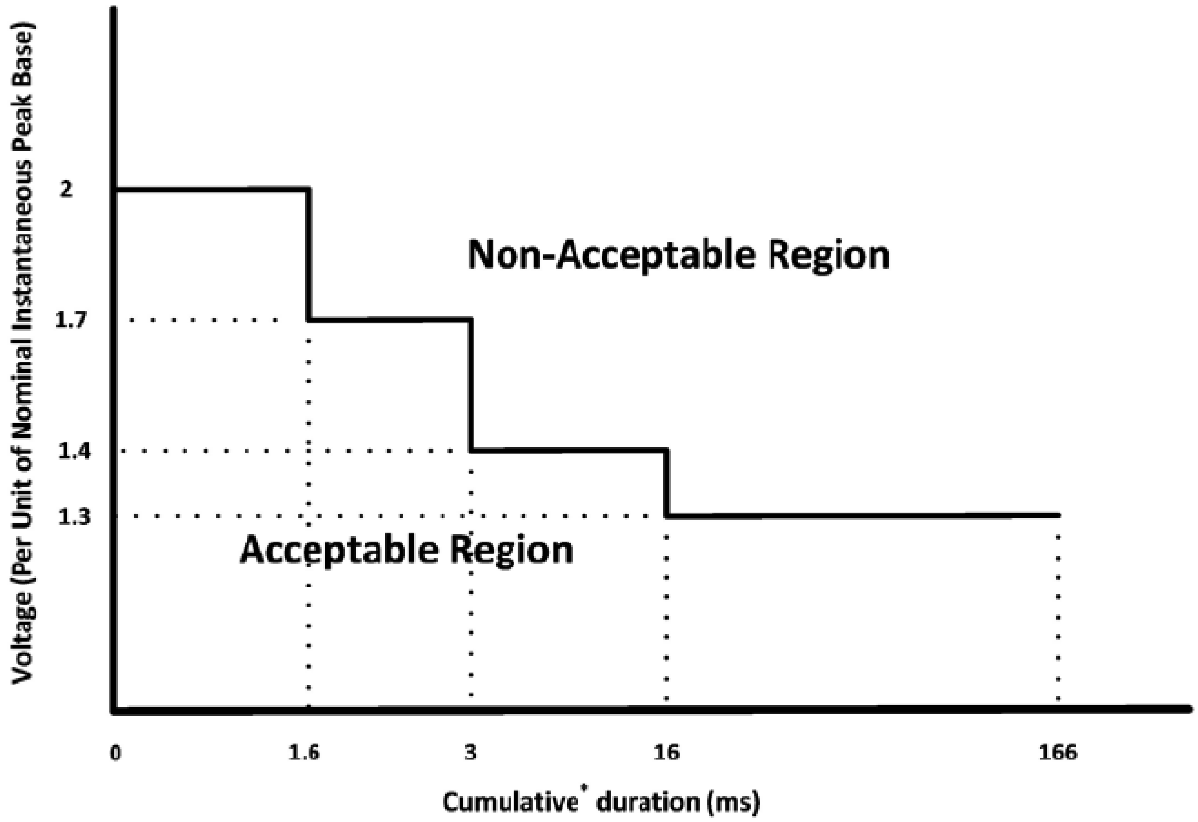
Table 8 below lists the transient analyses performed chronologically to ensure a safe and reliable DER interconnection. This paper discusses the elements affected by specific changes in DER project design as well.

Table 8: Elements of a Time Domain Study

Study Component	Purpose	Reference
Load Rejection Overvoltage Analysis	Evaluates cumulative instantaneous overvoltage durations due to high generation-to-load ratios. Figure 1 below shows the transient overvoltage limits evaluated for compliance with IEEE 1547.	IEEE 1547-2018, Section 7.4.2
Ground Fault Overvoltage Analysis	Evaluates cumulative instantaneous overvoltage durations due to unbalanced fault conditions. Figure 1 below shows the transient overvoltage limits evaluated for compliance with IEEE 1547.	IEEE 1547-2018, Section 7.4.2
Risk of Islanding Evaluation	The project must trip offline within two seconds of the formation of an unintentional island.	IEEE 1547-2018 Section 8.1
Underfrequency Load Shed (UFLS) Impact Assessment	Ensures that the inverter LOMD function does not cause nuisance tripping of UFLS schemes.	PRC-006-NPCC-2
Control Interaction Assessment	Evaluates whether unwanted oscillatory behavior occurs with nearby projects operating in tandem.	

These analyses ensure compliance with the interconnection requirements of the host utility are met and ensure all inverter-based projects comply with UL 1741 and IEEE 1547. The results of these analyses are highly dependent on the DER project design and equipment, the point of interconnection (POI) to the grid, and other in-service or queued DER in the area.

Figure 1: IEEE 1547-2018 Section 7.4.2 Limitations of Cumulative Instantaneous Overvoltage



* means that 16 ms can be more than 1 cycle

2 Replacement Equipment Considerations

These considerations assume that the original System Impact Study (SIS) has been completed and the needed grid reinforcements have already been identified. Additionally, this section assumes that a protection coordination study has not started and operational settings (i.e., Volt/Var settings) have not been determined. If a coordination or operational study has been completed, it may have to be redone to accommodate the equipment changes. Further assumptions are:

- The proposed system kVA and kW output are equal to or less than the original system studied in the SIS[2].
- The point of interconnection (POI) of the proposed system is the same as the POI of the system originally studied in the SIS.

Any impacts or upgrades identified in a regional transmission-level cluster study may not be addressed by the considerations below.

2.1 Factors for Inverters[3]

Table 9 below summarizes the relevant characteristics to consider when selecting replacement inverters. The following sections discuss each of these characteristics.

Table 9: Inverter characteristics to consider when selecting replacement inverters

Relevant Inverter Characteristic	Study Component	Mitigations for Re-Study Requirement
Number of Inverters		Changing the number of inverters (going from 10 to 20 for example) may also trigger a restudy.
Short Circuit Contribution	Effective Grounding	If the newly proposed system uses the same inverter model and has a short circuit contribution that is equal to or less than the short circuit contribution originally studied in the SIS, then the effective grounding requirement will not need

[2] Although this paper focuses on considerations that would avoid re-running SIS analyses, it does not address that some grid reinforcements may be avoided with a reduction in proposed system kVA output, if restudied.

[3] Any change request involving inverters will require the submittal of inverter data sheets. A PSCAD model will also be required if a time domain study is performed.

<table>
<tr><th>Relevant Inverter Characteristic</th><th>Study Component</th><th>Mitigations for Re-Study Requirement</th></tr>
<tr><td rowspan="2"></td><td></td><td>changing and the effective grounding component of the SIS need not be re-run.
If the original SIS uses a minimum assumed SC contribution that is equal to or greater than most available inverters, it provides flexibility to choose a replacement inverter without having to re-evaluate effective grounding in most scenarios. This is a decision for the host utility, however, new inverters will require a full restudy.</td></tr>
<tr><td>Short Circuit Analysis (SC)</td><td>If the newly proposed system has a short circuit contribution that is equal to or less than the short circuit contribution of the originally studied in the SIS, the short circuit analysis need not be re-run. Any impacts to coordination settings will be addressed in the Protection Coordination Study.</td></tr>
<tr><td rowspan="7">Reactive Power Capability</td><td>Volt/Var Settings</td><td rowspan="7">These SIS components need not be restudied if:
1. The original SIS required unity power factor operation.
or
2. The original SIS required Volt/Var or off-unity operation and the newly proposed system has the Volt/Var capability to supply the maximum amount of Vars required in the original SIS.</td></tr>
<tr><td>Off-Unity PF</td></tr>
<tr><td>Reactive Power</td></tr>
<tr><td>Steady-State Voltage</td></tr>
<tr><td>Regulator Tapping</td></tr>
<tr><td>Voltage Change</td></tr>
<tr><td>% Pickup Analysis</td></tr>
<tr><td>Firmware PSCAD Model</td><td>Risk of Islanding (ROI) - TDS</td><td>The ability of an inverter to pass the time domain ROI evaluation often depends on the effectiveness of its Loss of Mains Detection (LOMD) algorithm. Therefore, any changes to firmware/PSCAD model which may impact the LOMD algorithm will require this SIS component to be restudied.
Also, the ROI screen includes a step that checks whether a single inverter manufacturer makes up more than two-thirds of the total inverter-based generation on the bus. If the proposed inverter is from a different manufacturer, this screen must be rerun. If the screen fails, an ROI analysis must be performed.</td></tr>
</table>

Relevant Inverter Characteristic	Study Component	Mitigations for Re-Study Requirement
	Load Rejection Overvoltage (LROV) - TDS Ground Fault Overvoltage (GFOV) - TDS	The ability of an inverter to pass the time domain LROV and GFOV evaluations often depends on the effectiveness (i.e., ability to limit cumulative overvoltage) of its instantaneous overvoltage (TrOV/SPOV) protective function. Therefore, any changes to firmware/PSCAD model which may impact this protective trip function will require LROV and GFOV components to be restudied.
	Under Frequency Load Shedding (UFLS) - TDS	If UFLS is not present on the interconnecting feeder **or** if the original SIS required an existing UFLS system to be relocated to a different feeder, then the UFLS interaction analysis does not need to be re-run. Otherwise, the ability of an inverter to pass the time domain UFLS evaluation often depends on its Loss of Mains Detection (LOMD) algorithm interacting with the UFLS scheme. Therefore, any changes to firmware/PSCAD model which may impact the LOMD algorithm will require the UFLS analysis to be restudied.
	Control Interaction - TDS	When operating in Volt/Var mode and not equipped with a power-plant controller (PPC), the reactive power/voltage stability of the project depends on the inverter's internal control loops which are represented within the PSCAD model. Therefore, any changes to firmware/PSCAD model which may impact these control loops will require this control interaction component to be re-run.

2.1.1 Short Circuit Contribution

Changes to inverters in short circuit contributions can impact effective grounding design and equipment interrupting ratings.

If the newly proposed system uses the same inverter model and has a short circuit contribution that is equal to or less than the short circuit contribution originally studied in the SIS, then the effective grounding requirement will not need changing and the effective grounding component of the SIS need not be re-run.

If the newly proposed system uses the same inverter and has a short circuit contribution that is equal to or less than the short circuit contribution originally studied in the SIS, the short circuit analysis need not be re-run. Any impacts to coordination settings will be addressed in the Protection Coordination Study.

If the newly proposed system uses a new inverter model, a full restudy is required.

2.1.1 Reactive Power Capability

As it can impact the total kVA output of a project, changes in inverter reactive power (Var) capability impact Volt/Var operation, off-unity power factor operation, equipment thermal ratings, reactive power compensation, steady-state voltage, regulator tapping, and voltage flicker results. Changes in Var output can also impact % pickup settings for protective devices.

If the original SIS called for unity power factor operation by the utility, then the Volt/Var settings, reactive power compensation, steady-state voltage, regulator tapping, voltage change, and protective % pickup and reach analyses will not need to be restudied.

If the original SIS required Volt/Var or off-unity operation by the utility, and if the proposed system has the Volt/Var capability to supply the maximum amount of Var required in the original SIS, then this SIS component need not be restudied.

2.1.3 PSCAD/Firmware Model

The PSCAD model of the inverter firmware allows the inverter's controls to be modeled for transient analyses and interactions. Overall, if the proposed system has a short circuit contribution less than or equal to what was studied in the original SIS, and if the new system is capable of contributing the full reactive power (Var) required in the original SIS, and if the proposed system uses the same PSCAD model/firmware as that used in the original SIS, then none of these time domain analyses need to be restudied.

2.1.3.1 Risk of Islanding (ROI)

The ability of an inverter to pass the Time Domain Study ROI evaluation often depends on the effectiveness of its Loss of Mains Detection (LOMD) algorithm. Therefore, any changes to the firmware/PSCAD model which may impact the LOMD algorithm will require this SIS component to be restudied.

Also, the ROI screen includes a step that checks whether a single inverter manufacturer makes up more than two-thirds of the total inverter-based generation on the bus. If the proposed inverter is from a different manufacturer, this screen must be rerun. If the screen fails, a time domain study must be performed.

2.1.3.2 Load Rejection Overvoltage (LROV) and Ground Fault Overvoltage (GFOV)

The ability of an inverter to pass the time domain LROV and GFOV evaluations often depends on the effectiveness of its instantaneous overvoltage (TrOV/SPOV) protective trip function. Therefore, any changes to the firmware/PSCAD model which may impact this protective function will require this SIS component to be restudied.

2.1.3.3 Under Frequency Load Shed (UFLS)

If UFLS is not present on the interconnecting feeder, or if the UFLS system is being relocated to a different feeder, then the UFLS interaction analysis does not need to be re-run.

Otherwise, the ability of an inverter to pass the time domain UFLS evaluation often depends on the effectiveness of its Loss of Mains Detection (LOMD) algorithm in the inverter. Therefore, any changes to firmware/PSCAD model which may impact the LOMD algorithm will require this SIS component to be restudied.

2.1.3.4 Control Interaction

When operating in Volt/Var mode and not equipped with a power-plant controller (PPC), the reactive power/voltage stability of the project depends on the inverter's internal control loops which are represented within the PSCAD model. Therefore, any changes to the firmware/PSCAD model which may impact these control loops will require this SIS component to be re-run.

2.2 Factors for Generator Step-Up (GSU) Transformers

Generator step-up transformer parameters are critical to the performance of DER projects. As the path from the inverter output to the grid, the overall impedance of the GSU, including its X/R ratio, winding configuration, and grounding impedance have a dramatic impact on short circuit levels, effective grounding, and Ground Fault Overvoltage (GFOV). In addition, voltage, thermal, and reactive results; protective minimum pickups and reach; and Volt/Var settings are also impacted. Further, changing the quantity of GSUs for a project will impact the cabling and its associated impedance, transformer inrush, and the associated protection settings.

2.2.1 Number of GSU Transformers

Changing the number of GSU transformers on a project may require a restudy, even if kVA remains the same. Versant will review the specifics of the proposed change and make a determination whether a restudy is necessary or not.

2.2.2 kVA Rating

All other GSU parameters remaining the same, maintaining or decreasing the GSU kVA rating will not require a restudy. However, as Footnote 1 above notes, restudying a project at a reduced size may potentially avoid required grid reinforcements determined from the original study.

2.2.3 Impedance

If the impedance of the GSU (in ohms) remains the same or increases, without changing the winding configuration or neutral grounding, restudying the SIS will not be required. The impacts must still be addressed in the protection coordination and operational studies.

2.2.4 Winding Configuration

Changing the winding configuration from what was originally studied typically requires a restudy as it dramatically impacts the zero sequence impedance for imbalanced fault currents. This impacts effective grounding, short circuit, protective pickup and reach, and GFOV results. Versant will review the specifics of the proposed change and make a determination whether a restudy is necessary.

2.2.5 Neutral Grounding Impedance

Like winding configuration, changing the neutral grounding impedance from what was originally studied would require a restudy as it dramatically impacts the zero sequence impedance for imbalanced fault currents. This impacts effective grounding, short circuit, protective pickup and reach, and GFOV results.

2.3 Factors for Grounding Transformer Banks

Grounding transformers are included in projects to provide a source of ground fault current during line-to-ground faults and to limit the magnitude of over-voltages when ground faults occur in ungrounded wye or delta connected systems. Changes to grounding bank parameters affect effective grounding, short circuit, and GFOV.

2.3.1 Grounding Transformer Bank Location

Moving the grounding transformer bank connection from the GSU transformer primary side to the secondary side requires a restudy.

2.3.2 Winding Configuration

Grounding transformers can have either Wye-Delta or Zig-Zag winding configurations. As long as the kVA rating and impedance remain the same, changing the grounding transformer winding configuration will not require a restudy.

2.3.3 Impedance

If the grounding bank impedance (in ohms) remains the same or decreases, restudy will not be required, and the impacts can be addressed in subsequent protection coordination and operational studies

2.3.4 Bushing Connections

As grounding transformers are needed to be in service to prevent overvoltages associated with unbalanced faults, project grounding transformers require a positive interlock to be installed with the associated inverters so that if they are removed, associated inverters cannot operate. The interlock must be failsafe, such that any circuit or device failure will result in a safe mode of operation.

For grounding banks connected on the high side of the GSU, changing the bushing specification from live-front (i.e., bolted connections) to dead-front (i.e., insulated elbow connections) would require a positive interlock to be installed with the associated inverters so that if the grounding transformer is removed from service, the associated inverters cannot operate. Otherwise, the grounding bank bushing connections do not impact the SIS results.

Appendix G – PSCAD Modeling Requirements

The following pages in this appendix list the PSCAD modeling requirements for accuracy, usability, and efficiency features, as well as accessible parameters and minimum documentation requirements. These requirements are based on those found in the ISO-NE "PP05-6 Appendix C-1 – Electromagnetic Transient Modeling Requirements,"[4] dated April 3, 2024, and have been modified by Versant. DER project developers will need to confirm that the PSCAD models they are submitting with Interconnection Applications conform to these requirements.

If PSCAD models fail the Versant model review and validation process conducted before system impact studies begin, advancing to the study phase of the interconnection process will be delayed until an appropriate working model is confirmed. At a minimum, Versant model validation will include, but is not limited to, the following tests:

- Initialization and flat run
- Balanced fault ride-through
- Unbalanced fault ride-through
- Voltage ride-through
- Active power reference step change
- Grid frequency response and ride-through
- Grid voltage phase angle change ride-through
- Voltage and frequency protection verification
- Volt/Var response

[4] https://www.iso-ne.com/static-assets/documents/100010/pp5_6_appendix_c1.pdf

Model Accuracy Features

In order to be sufficiently accurate, the model provided for each facility shall:

1. Represent the full detailed inner control loops of the power electronics. Models cannot use the same approximations classically used in transient stability modeling and must fully represent all fast inner controls, as implemented in the real equipment. Models manually translated block-by-block from MATLAB or control block diagrams are unacceptable. A full power transistor (e.g. IGBT) representation is the preferred model. Models must embed the actual hardware code into a PSCAD component. The controller source code may be compiled into DLLs or binaries if the source code is unavailable due to confidentiality restrictions.
2. Average source representation is discouraged. However, if an average source representation is utilized (e.g., switching frequency greater than 40 kHz), it shall maintain full detail in the inner controls and DC side protection features. Sufficient technical justification must be provided on the usage of an average source representation.
3. DC side protections, and any current, power or energy limitations that could affect plant ride-through shall be represented in the model. Modeling the DC side with an ideal voltage source is not acceptable if such a representation prevents the possibility of protection operation during external system events.
4. Represent all pertinent control features as they are implemented in the real controls (e.g. customized PLLs, ride-through controllers, etc.) using actual hardware code.
5. Represent Power Plant Controller (PPC) as implemented in the real controls and represent the specific controllers used in the plant, if applicable. This includes automatic voltage regulation, specific measurement methods, and transitions into and out of ride-through modes, among others. Generic PPC representations are not acceptable.
6. Communication and sample and hold delays between PPC and inverter must be modeled, if applicable.
7. Represent common plant controller functionality if there are multiple plants using the same technology or multiple technologies (e.g. Hybrid ESS/PV), if applicable. If supplementary or multiple voltage control devices (e.g. STATCOM) are included in the plant, these should be coordinated with the PPC.
8. Represent Sub Synchronous Oscillation (SSO) mitigation and/or protection including the ability to enable and disable SSO mitigation/protection, if applicable.
9. Represent shunt capacitor and reactor banks and any dynamic reactive devices. The controls should be modeled if the equipment dynamically responds within 10 seconds after a disturbance.
10. Represent all pertinent electrical and mechanical configurations, such as filters and specialized transformers. Mechanical features (such as gearboxes, pitch controllers, etc.) should be included in the model if they affect electrical performance. Any control or dynamic features of the actual equipment that may influence behavior in the simulation period (up to 30 seconds post-disturbance) but are not represented or are approximated must be clearly identified.
11. Have all pertinent protections modeled in detail for both balanced and

unbalanced fault conditions. Typically, this includes overvoltage and undervoltage protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection, among others. Any protection, which can influence dynamic behavior or plant ride-through in the simulation period (up to 30 seconds post-disturbance), must be included.

12. Accurately reflect behavior throughout the valid (MW and MVAR) output range from minimum power through maximum power.

13. Model main power transformer (MPT)[5] and generator step up (GSU) saturation based upon transformer test reports available. If such data are not available, reasonable approximate data for transformer saturation shall be used and documented. Data include magnetization model, magnetizing current, air-core reactance, knee voltage of winding-limb, loop width and any other relevant information.
14. Include detailed representation of any hardware or software filters for wind turbine controllers, if applicable.
15. The specific implementation of frequency measurement equipment should be modeled. If actual equipment model is not available, a smoothed master library FFT or master library PLL shall be used.
16. Be configured to match planned (or installed) site-specific equipment settings[6]. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated. It is unacceptable to use default parameters. If POI SCR is unknown at the time of model submission, it is recommended to parametrize to a POI level SCR of 3 and X/R of 10 as an approximate representation of a weak system. If studies show a SCR lower than 3, additional model tuning may be required.

Model Usability Features

In order to allow study engineers to perform system studies and analyze simulation results, the model provided for each facility shall:

1. Have pertinent control or hardware options accessible to the user (e.g. adjustable protection thresholds, real power recovery ramp rates frequency or Volt/Var settings, voltage control response time). Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) should be accessible to facilitate analysis and should clearly identify why a model trips during simulations.
2. Be capable of accurately running at a time step of 10 microseconds or higher and not be restricted to operating at a single time step, but within a range (e.g. 10-20 microseconds). Models requiring a smaller time step may indicate that the control implementation has not used the interpolation features of PSCAD or is using inappropriate interfacing between the model and the larger network. If power transistor switching frequency prevents accurate switching representation at 10 microseconds using interpolation, an average source approximation may be used (see "Model Accuracy Features," Requirement 2). Smaller time steps will be considered on a case-by-case basis.
3. Include a sample implementation test case that contains the configured model connected to a simple AC system. If a PPC is required, then the sample case should include the PPC and a manual should also be provided for the PPC model. Access to technical support engineers is desirable.

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[5] The MPT is the power transformer that steps up voltage from the collection system voltage to the nominal interconnecting system voltage for dispersed power producing resources.

[6] It is currently standard practice for Versant to perform the site-specific modeling using PSCAD models provided by the DER project developers.

4. Be capable of initializing itself. Models shall initialize and ramp to full output without external input from simulation engineers. Any slower control functions which are included (such as switched shunt controllers or power plant controllers) must also accept initial condition variables, if required. Note that during the first few seconds of simulation (e.g. zero to two seconds), the system voltage and corresponding terminal conditions may deviate from nominal values due to other system devices initializing, and the model must be able to tolerate these deviations or provide a variable initialization time.
5. Accept external reference values. This includes real and reactive power reference values (for Q control modes), or voltage reference values (for V control modes) and utilize a single parameter for adjusting real power, and separately, a single parameter for adjusting voltage setpoints. Models must accept these reference variables for initialization and be capable of changing these reference variables mid-simulation, i.e. dynamic signal references.
6. Allow protection models to be disabled. Many studies result in inadvertent tripping of converter equipment, and the ability to disable protection functions temporarily provides study engineers with valuable system diagnostic information.
7. Allow the active power capacity of the model to be scaled. This is distinct from a dispatchable power order and is used for modeling different plant capacities (e.g. if a portion of the plant is offline).
8. Allow the plant to be dispatched at any output within its operating range. If a minimum output is required, sufficient technical justification shall be provided. This is distinct from scaling a plant from one unit to more than one, and is used for testing plant behavior at various operating points.

Model Efficiency Features

In order to improve study efficiency and model compatibility, the following efficiency features are required. Note that no feature should compromise model accuracy. The model shall:

1. Be compatible with Intel Fortran compiler versions 15 and higher and be compiled with Visual Studio 2015 or newer.
2. Be compatible with PSCAD version 4.6.3 and higher.
3. Initialize to user defined terminal conditions within five seconds of simulation time.
4. Support multiple instances of its own definition in the same simulation case.
5. Support the PSCAD "snapshot" and "multiple run" features.
6. Allow replication in different PSCAD cases or libraries through the "copy" or "copy transfer" features.
7. Not use or rely upon global variables in the PSCAD environment and not use multiple layers in the PSCAD environment, including "disabled" layers.
8. Inform the user through messages to the progress output device when the system conditions are beyond plant operational limits or otherwise not consistent with valid operating conditions for the plant.
9. Show error/status codes. Only those error/status codes which translate into a distinct electrical system response at the low voltage terminals of the unit, e.g. normal, fault, stop, low or high voltage ride-through activation, unstable mode identification.

10. Clearly identify the OEM's EMT model release version and the applicable corresponding hardware firmware version.

Accessible Parameters

All models shall allow modification to parameters typically requiring site-specific adjustments. Where applicable, these include:

- All applicable set-points including but not limited to (shall be adjustable before and during a simulation run):
    - Active and reactive power
    - Voltage and frequency (e.g. Volt/Var, frequency droop, open-loop response times)
    - Power factor
- Deadband, droop, delays (including communication delays) and slow outer loop controls for any applicable control system such voltage and frequency control.
- Active power ramp rate adjustment.
- Voltage and frequency protection settings.
- Fault ride-through activation and deactivation thresholds.
- Active and reactive current injection/absorption settings during a fault.
- Number of in-service inverters which can be adjusted before and during a simulation run.
- Other parameters such as PI gains for inner/outer current/voltage control loops (including PLL, DC link current and voltage control, and any other control loops which can have an impact on system performance).

Model Documentation

At a minimum, the model documentation shall include the following:

1. A user manual for the PSCAD model which includes the following information:
    a. Specific equipment model(s) for which the provided document is valid.
    b. Detailed description of all control schemes that respond to voltage or frequency disturbances on the system. These include but not limited to:
        i. Voltage and frequency control (e.g. Volt/Var, frequency droop, open-loop response times)
        ii. Power factor and/or reactive power control
        iii. Priority modes and controls including description of voltage and frequency ride-through characteristics such as activation/deactivation thresholds, control mode during ride-through, etc.
        iv. Protection schemes and settings for, but not limited to:
            1. Over- and undervoltage protection
            2. Over- and underfrequency protection
            3. Inter-trip or runback protection scheme
            4. Any other relevant protections (e.g. frequency rate of change protections, SPOV)
    c. A table of all user-definable settings and status code outputs, range of acceptable values for each user-modifiable variable and a description of each entry's function. An image of the model instance corresponding to the table must also be provided.
    d. A table of all signals fed to the Power Plant Controller such as feedback

from inverter, grid measurements, reference set-points, etc. The table shall also include the parameter units (specify the base of all per unit parameters) and a description of each entry's function.

   e. A table of all trip signals and a description of each entry.

2. The following completed MA-TSRG PSCAD Checklist documents:
   a. PSCAD Checklist Instructions: (https://www.mass.gov/doc/tsrg-pscad-checklist-instructions/download)
   b. PSCAD Checklist Table: (https://www.mass.gov/doc/tsrg-pscad-checklist-table/download)

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