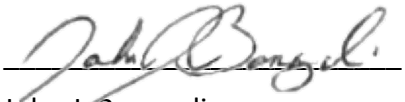
FOREWORD

The purpose of this document is to provide guidelines for the design and interconnection of (customer-owned) distributed energy resource equipment with Unitil's electric power system.

Any questions or inquiries regarding information provided in this document should be referred to the Manager of Distribution Engineering or the Director of Engineering.



Dec. 18, 2025

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Date

REVISION HISTORY

Revision #	Date	Description of Changes
0	03/20/2000	Initial Issue
1	05/01/2000	General update
2	04/01/2017	General update
3	12/18/2025	General update and title change

Table of Contents

1.0 Introduction

1.1 Purpose

The purpose of this document is to provide a guide for the design and interconnection of Distributed Energy Resources (DER) to the Unitil Electric Power System (Company EPS). Although each DER Facility may be unique, each Facility must meet minimum requirements for a safe and effective design and satisfy the interconnection process applicable to that Facility. This guide is provided to assist in communicating those minimum design requirements and identifying steps required to satisfy the interconnection process.

1.2 Policy

It is the policy of Unitil and its distribution company affiliates (the "Company") to permit DER operating in parallel with the Company EPS whenever it can be done without adverse effects to the general public or to the Company's equipment or personnel.

1.3 Applicability

The Guideline for Design and Interconnection of DER is applicable to DER that is proposed to electrically interconnect (or run in parallel) with the Company EPS.

2.0 Definitions

Certified: Equipment which has been tested in accordance with the applicable requirements of the latest version of IEEE 1547 by a Nationally Recognized Testing Laboratory, has been labeled as such, and is publicly listed by the NRTL at time of the interconnection application submission.

Company: Unitil and its distribution company affiliates

Company Electric Power System (Company EPS): The electrical facilities owned, controlled, and/or operated by the Company used to provide transmission or distribution services to its customers.

Critical Service Load: A subset of Station Service Load which is specific to the electric energy used for critical support of the operation of the ESS. Critical Service Load includes the HVAC of the ESS only, fire suppression system, and the inverter control system of the ESS.

Distributed Energy Resource (DER): A source of electric power that is not directly connected to the bulk power system. DER includes both generators and energy storage technology capable of exporting power to the Company EPS.

Energy Storage System (ESS): A commercially available technology that is capable of absorbing electricity, storing it for a period of time, and thereafter dispatching the electricity.

Facility: All DER, taken as a group, that is owned and operated by the Interconnecting Customer and located on the Customer's side of the PCC that has the capability to operate in parallel with the Company EPS.

Islanding: Generation serving utility load (or lines) without a synchronizing utility source connected.

ISO-NE: Independent System Operator - New England.

Interconnecting Customer: The entity that owns and/or operates the Facility proposing to interconnect or interconnected to the Company EPS, with legal authority to enter into agreements regarding the construction or operation of the Facility

Light Load: Minimum modeled load level used for analysis of the impact of generator interconnection on the Company EPS.

Local Electric Power System (Local EPS): The electric power system contained within a single premise or group of premises i.e. the electric power system owned, controlled, or operated by the Interconnecting Customer and Utility Customer. The Company EPS serves the Local EPS.

NERC: North American Electric Reliability Council.

NPCC: Northeast Power Coordinating Council.

Peak load: Maximum modeled load level used for analysis of the impact of generator interconnection on the Company EPS.

Point of Common Coupling (PCC): The point where the Local EPS connects to the Company EPS. Otherwise known as the point where the ownership changes from Customer of Utility.

Point of Interconnection (POI): The point where the Facility connects to the existing Utility grid infrastructure.

Power Control System (PCS): An electrical system that monitors and controls the output of one or more power production sources.

Protection System: The combination of protective relays, potential transformers, current transformers, power circuit breakers, and other associated auxiliary equipment installed at the Facility to detect abnormal conditions on the Local EPS and initiate control circuit actions.

SCADA: Supervisory Control and Data Acquisition. A computer system for gathering and analyzing real time data used to monitor and control electric power systems.

3.0 Facility Design

There are minimum design requirements for all DER Facilities operating in parallel with the Company EPS. The Company reserves the right to require modifications to the Facility design beyond what is described in these guidelines to ensure a safe and effective design. Final design approval will be subject to Company review.

3.1 Base Design Considerations

All Facility designs should incorporate the following baseline design considerations:

3.1.1 Codes and Standards

The Facility design shall comply with the latest version of all applicable local, state, and federal codes, regulations, and standards; specifically, but not limited to:

- ANSI/IEEE C37.90 - Standard for Relays and Relay Systems Associated with Electric Power Apparatus
- IEEE Std C62.45TM-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits.
- NESC - National Electrical Safety Code
- NFPA 70 - National Electrical Code (NEC)
- IEEE 519 - Standard for Harmonic Control in Electrical Power Systems
- IEEE 1547 - Standard for Interconnecting Distributed Resources with Electric Power Systems
- UL 1741 - Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources
- Default IEEE 1547-2018 Setting Requirements – MA TSRG/ISO-NE Reference

Interconnection equipment, methods and practices shall comply with established standards of good utility practice for the New England region, as represented by the requirements and practices of the Company, ISO New England and other regional distribution companies. All wiring, connections, and devices shall be fit for purpose, properly applied, and installed in accordance with manufacturer instructions.

3.1.2 Labeling

Facility equipment accessible to and intended for Company use shall be plainly and permanently labeled for proper identification. This includes, but is not limited to, meter sockets and disconnect devices.

3.1.3 Character of Service

Facility equipment must be compatible with the character of service supplied by the Company at the Facilities' location.

3.1.4 Quality of Service

The interconnection of the Facility with the Company EPS shall not cause any reduction in the quality of service being provided to other customers of the Company.

The voltage from DER must be controlled so that the Company can maintain the distribution voltage within a bandwidth of 114 volts to 126 volts of a nominal voltage of 120 volts.

3.1.5 Harmonic Interference

The Facility must not cause harmonic interference on the Company EPS. The harmonic content of the voltage and current waveforms on the Company EPS must be restricted to levels within the limits specified in the latest edition of IEEE Standard 519.

3.1.6 Synchronizing

The Facility must properly synchronize with the Company EPS at a designated interrupting device. This "synchronizing device" may be a device other than the interconnecting device. The Facility design shall incorporate a protection scheme to prevent the closing of the synchronizing device while the Facility is out of synchronism with the Company EPS.

The Company will establish power factor and voltage hold limits on a case-by-case basis incorporating the actual unit capability and system characteristics at the point of interconnection.

3.1.7 Flicker

The Facility connecting or disconnecting from the Company EPS shall cause no more than a 3% instantaneous variation in voltage (flicker).

3.1.8 Power Factor Operating Limits

All Facilities are required to operate at a pre-determined range or value of power factor. It is expected the generator will operate at Unity power factor however, the actual power

factor requirements of each generator will be specific to their location on the Company EPS and will be determined by Company.

All customer-owned synchronous generators should be rated to operate continuously at any power factor between 90 percent lagging and 90 percent leading at any voltage level within +/- 5% of rated voltage.

3.1.9 Islanding

The Facility must detect and disconnect within two seconds if the Company EPS becomes intentionally or inadvertently de-energized as specified in IEEE 1547. The Facility must not energize a de-energized circuit. Facilities designed to operate in an islanded state energizing the Local EPS during loss of Company EPS shall incorporate a Microgrid Interconnection Device in the Facility design to completely isolate the Facility from the Company EPS during these operations.

3.1.10 Transient Overvoltage

The Facility shall limit its cumulative transient overvoltage per the cumulative overvoltage curve in clause 7.4.2 in IEEE 1547.

3.2 Design Requirements

3.2.1 Service Entrance

The Facilities service entrance must incorporate appropriate switching devices and interrupting devices rated for at least the maximum fault current available from the Company EPS and the fault current contribution of the Facility and capable of Interrupting the Facilities' step-up transformer magnetizing current as supplied from the Company system.

3.2.2 Revenue Metering

Suitable metering will be required at any location where DER is connected in parallel with the Company EPS. Metering will normally be provided to measure energy flow in two directions. Additionally, metering for the following Facility sizes shall be capable of providing interval measurement:

Massachusetts

Behind-the-meter Facilities larger than 1MVA

Stand-alone Facilities larger than 60 kVA

New Hampshire

All Facilities larger than 100 kVA

The Interconnecting Customer shall be responsible for providing and maintaining all necessary telecommunications lines and equipment per the Company's requirements.

3.2.3 Disconnect Switches and Devices

All Facilities will require a disconnect device at the Point of Common Coupling or a mutually agreed upon location. Facilities utilizing Certified Inverters may request an exemption from the Company. Exemptions will be granted based on State specific Interconnection Tariffs.

Disconnect switches shall be gang operated (for three-phase installations) and capable of:

- Interrupting the Facilities full generation capability.
- Providing a visible break when open
- Providing a means to be locked open, tagged, and grounded on the Utility side.
- Interrupting the Facilities step-up transformer magnetizing current as supplied from the Company system.

Company Access, Operation, and Disclaimers

The Interconnecting Customer shall provide direct unencumbered access to the disconnect switch to allow Company personnel to operate the disconnect switch at any time of the day and year without contacting the Interconnecting Customer.

The Company shall have the right to open the disconnect switch in accordance with the provisions outlined in the respective State Interconnection Tariffs. The Customer shall not attempt to operate any equipment, including customer owned equipment, which has been switched, tagged, opened, or locked out by Company personnel

The Company will not be responsible for problems or damage to the customer's equipment created by the operation of switching, protective devices, or other means of disconnection.

3.2.4 Customer-owned Interface Transformer

The Facility shall interface with the Company EPS through a transformer or bank of transformers of an adequate KVA rating and proper voltage rating for conversion from Facility's voltage to the Company EPS voltage.

For three-phase transformer installations the transformer connection and grounding arrangement shall be of a configuration that will not establish an additional ground current source to the Company EPS. The Company may require or allow other methods

of transformer neutral grounding, such as reactance grounding, under certain system configurations.

Allowable transformer winding configurations are as follows:

Primary (Utility)	Secondary (Facility)	Additional Requirements
Wye-grounded	Delta	Impedance Grounding (If Necessary)
Wye-grounded	Wye-grounded	Effectively Grounded DER Source
Wye-grounded	Wye-grounded	Secondary Grounding Transformer

3.2.5 Grounding

Any Facility larger than 250 kVA must be effectively grounded with appropriate interlocks preventing the Facility from operating if the effective grounding system is out of service or disconnected. Grounding system shall limit sustained over voltages on un-faulted phases during a line-to-ground fault to no greater than 1.25 times the normal phase-to-ground voltage.

3.2.6 Capacitors

Excitation or power factor correction capacitors may not be installed on induction generators without approval by the Company.

3.2.7 Protection Requirements

Each location where DER is connected in parallel with the Company EPS must have adequate Protection Systems per this section.

All DER interconnections shall provide protection against the following:

- Inadvertent and unwanted energizing of a dead line or bus.
- Interconnection while out of synchronization.
- Ground faults and phase faults.
- Frequency outside permissible limits.
- Voltage generated outside permissible limits.

The Protection System for the Facility shall be sufficiently redundant to provide adequate protection, as determined by the Company, upon the failure of any one component.

The use of a single all-inclusive relay package is generally not acceptable.

Interconnection relaying equipment, including instrument transformers, shall meet ANSI/IEEE standard C37.90 and be of a manufacturer and type generally accepted for use by the Company.

The Company will review all the relay settings to assure adequate protection for the Company's facilities.

The specified interconnection protection requirements are for the protection of the EPS and do not intrinsically provide any protection for the Customer's generator(s) or any other portion of the Customer's electrical system or equipment.

The Customer must provide for all additional protection schemes to protect the generator(s) and electrical system(s) and equipment.

Any discrete protective relays requiring testing or connection to the Company EPS, ABB type FT test blocks shall be provided to permit injection of test voltage or current as required, to verify the calibration and operation of the interconnection protection relays.

These test blocks shall also interrupt the relay trip outputs.

The Company must review and approve the location of the test points in the sensing and trip circuits as part of the initial design review.

All secondary wiring and connections of the interconnection relay system and its associated equipment shall meet all requirements of applicable federal, state and local electrical codes and good utility practice.

Screws, studs, nuts, and terminals used for electrical connections shall be of brass or plated brass.

The wire used will be no smaller than #14 AWG stranded copper, with insulation suitable for the particular application.

In no case will the insulation be rated for less than 600 volts.

Wire terminations shall be by use of non-soldered "crimp-style" ring lug terminals.

Primary or high voltage wiring of CT's, PT's, breakers, and related equipment shall be installed in accordance with all applicable sections of the National Electrical Code, National Electric Safety Code as well as applicable federal, state and local codes, Company standards, and all standards of good utility practice.

3.2.8 Protection Requirements for Synchronous Inverters

The following protective functions (at a minimum) shall be integrated in the inverter:

Function	Description
27	Under voltage (phase-to-phase or phase-to-ground)
59	Overvoltage (phase-to-phase or phase-to-ground)
81O/U	Over/Under Frequency

The inverter and electronic controller shall comply with the latest version of the following:

- Underwriters Laboratories 1741 "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources"
- IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems"

The inverter system shall include a surge protector on the utility side of the inverter. The surge protection system shall comply with testing criteria detailed in ANSI/IEEE standard C62.41 and shall be tested per UL 1449. It is recommended that this surge protector be integrated within the inverter. However, a separate surge protector may be used if the inverter does not comply with the surge protection standards.

3.2.9 Protection Requirements for Synchronous Generators

A synchronous generator is a source of current for a fault occurring on the Company's system.

The Facility must provide relaying to detect any faults on the Company's system or within the Facility, whether the fault is phase-to-phase or phase-to-ground.

At a minimum the customer shall install the following types of relaying:

Function	Description
27	Under voltage (phase-to-phase or phase-to-ground)

50	Instantaneous Overcurrent (each Phase)
51	Phase Time Delayed Overcurrent (each Phase)
51G	Ground Overcurrent
59	Overvoltage (phase-to-phase or phase-to-ground)
81O/U	Over/Under Frequency

The relay systems must work with and coordinate with the Company protection system to isolate the generating facility from the Company system per the following criteria:

The sensitivity of fault detection of the existing line protection is not substantially degraded

- The existing speed of fault clearing is not substantially degraded.
- The existing coordination margin between relays is not decreased.
- Existing non-directional line relays will not operate for faults external to the line due to the generating facility's current contribution to the fault.
- The sustained voltage on an un-faulted phase during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage.

If due to the interconnection of the Facility, the above criteria are violated, the Company will require the Customer to pay for the purchase and installation of any modification or replacement of protection systems to correct the violation and restore the protection to the level of protection prior to the interconnection.

The Customer may be required to use high-speed relaying if time-delayed protection would result in degradation of the speed or sensitivity of the existing protection on the Company system.

The Customer may be required to provide breaker failure protection, which may include a Direct Transfer Trip (DTT) scheme to the Company's station(s).

The Customer is responsible for procuring any communications necessary between the Customer's facility and the Company's stations.

3.2.10 Protection Requirements for Induction Generators

Induction generators normally are not a source of current to a fault on the Company's system, as the generator receives its excitation from the Company System.

The Customer may be required to install capacitors to limit the adverse effects of drawing reactive power from the system for excitation of the generator.

Capacitors for supply of reactive power at or near the induction generator with a kVAR rating greater that 30% of the generator's kW rating may cause the generator to become self-excited.

If self-excitation can occur the Customer shall be required to provide protection as specified for synchronous generator.

As a minimum the customer shall install the following types of relaying:

Function	Description
27	Undervoltage (phase-to-phase or phase-to-ground)
59	Overvoltage (phase-to-phase or phase-to-ground)
81O/U	Over/Under Frequency

3.2.11 Facility Import/Export Limiting

A Facility intending to limit import/export power flow across the PCC shall incorporate design requirements relevant to the manner in which the limiting is accomplished. These requirements are detailed below. In all instances, the maximum import/export power values, maximum inadvertent import/export power values, control type, and CTs/VTs with manufacturers stated accuracy if applicable must be accounted for on the Facility one-line diagram. The Company does not allow variable import/export settings (i.e. scheduled import/export limiting).

<u>Power Control Systems</u>

- Shall be UL3141 Certified
- Response time delay not to exceed 10 seconds

Utility Grade Relay

- System as a whole shall be Certified for intended use
- ANSI 32 Element
- Response time delay not to exceed 10 seconds

Nameplate Reduction (i.e. De-Rating)

- Rating capacity changes shall be implemented by the manufacturer or their representatives
- The affected equipment shall have a replacement nameplate or engraved phenolic placard affixed indicating the Reduced Rating Capacity
- A letter from the manufacturer confirming the Reduced Rating Capacity and referencing the serial numbers of the affected equipment shall be provided to the Company

The Company reserves the right to require redundant protection for Facilities limiting import/export, notwithstanding the requirements of Section 3.3.2.

3.2.12 Energy Storage Systems

Facilities incorporating Energy Storage Systems (ESS), either co-located with other DER or as a stand-alone system, have unique characteristics due to their ability to act both as a source of positive load (charging) and negative load (discharging). ESS shall incorporate design requirements relevant to the manner in which they will operate.

Charging Method: ESS designed to charge from the Company EPS, either as the sole charging source or supplemental to a co-located DER charging source, shall supply a load data sheet for evaluation through the standard load request process at the Company. ESS charging solely from co-located DER are exempt from this requirement, assuming all conditions of section 3.2.11 are met.

Discharging Method: ESS designed to limit discharge to on-site consumption only shall comply with all conditions of section 3.2.11. ESS designed to discharge as a grid forming source for co-located DER during loss of Company EPS source shall incorporate a

Microgrid Interconnection Device in the Facility design to completely isolate the Facility from the Company EPS during these operations.

Remote Monitoring and Control: ESS 250 kVA or larger shall comply with Remote Monitoring and Control requirements in section 3.3.3.

Wholesale Charging: Stand-alone ESS requesting wholesale distribution service under the FG&E Wholesale Distribution Tariff shall comply with the following design requirements applicable to the configuration of charging load, Critical Service Load, and station service load[1] at the Facility:

- ESS Charging Load: Dedicated meter required. Critical service loads are permitted to be behind this meter.

- Critical Service Load: Service under the Wholesale Distribution Tariff allows Critical Service Load to be supplied and metered under the main ESS Charging Load meter. Otherwise the Critical Service Load must be incorporated under the Station Service Load meter and may require an additional, dedicated, meter, if Wholesale Distribution service is requested for the Critical Service Load. .

- Station Service Load: If the total station service load is limited to IT and communications equipment, lighting, site safety and security equipment, and the total load of this type is limited to 10kW and 15,000kWh annually, it is considered "de-minimis", and no dedicated meter for the Station Service load is required. Otherwise a separate dedicated meter is required.

3.3 Additional Design Requirements – Facilities Larger Than 500 kVA

3.3.1 Recloser

A Company owned electronic recloser is required at all Facilities larger than 500 kVA. A typical installation will also incorporate Company owned disconnects or a gang operated switch. Existing pole configurations, space, easement limitations or other factors may necessitate an adjustment to this requirement, determined solely at the Companies discretion.

3.3.2 Redundant Relaying

Facilities larger than 500 kVA must have a utility grade relay as a redundant protection device to the Generator's main protection functionality. The relay is to be programmed

[1] Station service loads include the heating, lighting, air conditioning, and office equipment needs of the buildings at the ESS site, and for operating the electric equipment that is on the ESS site.

with the minimum protection elements described in section 3.2.7. The Company owned recloser installed at the PCC is accepted as the redundant device for any relaying functions activated in the recloser.

In the event the Company determines a typical installation of a Company owned recloser is not feasible per section 3.3.1, the Interconnecting Customer will be required to incorporate a utility grade relay in their Facility design.

3.3.3 Remote Monitoring and Control

Facilities larger than 500 kVA must provide real-time remote monitoring and control of the DER for the Companies use. This size threshold is reduced to 250 kVA or larger for ESS Facilities, per the ESS operational tariff. Company provided SCADA equipment installed on the Company owned recloser at the PCC will provide this functionality in a typical installation.

In the event the Company determines a typical installation of a Company owned recloser is not feasible per section 5.3.1, the Company will provide a remote terminal unit (RTU) with enclosure for remote monitoring and control via SCADA. The RTU will interface with the Facilities utility grade relay, monitoring any quantity of Indications and Analogs the Company may require with control functionality including, but not limited to, tripping of the Facility's main generator breaker and preventing closing of the Facilities' main generator breaker.

In the event additional monitoring points are required (e.g. monitoring of net power flow at the revenue meter for behind-the-meter installations) an additional SCADA meter may be provided by the Company and installed at the Facility.

4.0 Interconnection Process

The Company requires all DER to apply for interconnection to the Company EPS. This includes new construction Facilities and expansion or modification of existing Facilities. The application process differs between Massachusetts and New Hampshire. This section provides a general overview of the interconnection process. Detailed State specific processes can be found in the applicable references listed below.

Massachusetts:

- Fitchburg Gas and Electric Light Company Standards for Interconnection of Distributed Generation Schedule IC
- Fitchburg Gas and Electric Light Company Operational Parameters For Energy Storage Systems
- Fitchburg Gas and Electric Light Company Wholesale Distribution Tariff

New Hampshire:

- Unitil Energy Systems, Inc., Interconnection Standards For Inverters Sized Up To 100 kVA
- New Hampshire Code of Administrations Rules, Chapter PUC 900 Net Metering For Customer-Owned Renewable Energy Generation Resources of 1,000 Kilowatts Or Less

4.1 Interconnection Application

An interconnection application must be submitted by the Interconnecting Customer or their representative to the Company to initiate the request for interconnection. Interconnection applications are submitted through the Company online application system.

4.2 Required Documentation – Application Submission

The following documentation must accompany the initial interconnection application submission:

4.2.1 Agreement, Consent, and Informational Forms

Applicable State Interconnection Tariff or Rule Exhibits and State Interconnection Tariff or Rule Schedules

4.2.2 One-Line Connection Diagram

One-Line diagram depicting how the system components are electrically connected. A PE Stamp is required for Facilities larger than 25 kVA. A revision log shall be documented on the drawing with a description and date of each revision. Each revision must be signed or initialed by the designer. At a minimum, the following must be included when applicable:

- **Main Service Panels, Subpanels, and Switchgear to include:**
  - Main breakers with ratings
  - DER connection breaker or line tap
- **Metering**
  - Utility service meter with meter number
  - Utility owned Facility production meters
  - Customer owned meters

- **AC Utility Disconnect**
- **Generators/Inverters (Proposed and Existing) to include:**
    - Manufacturer and model number
    - Output voltage
    - PV Systems – PV modules including quantities and size
- **Related Equipment (e.g.):**
    - Transfer switches
    - Microgrid Interconnection Devices
    - Customer owned transformation to include primary and secondary voltage, winding configuration, nameplate rating, impedance, and grounding characteristics
    - Relaying and other protective devices to include:
        - Trip circuits
        - Settings table
        - Current transformers (CTs) and Voltage Transformers (VTs) with ratios and accuracy
- **General Facility Details**
    - Service voltage
    - Total system size in kVA
    - Address of Facility
    - Demarcations for interior and exterior equipment
    - Demarcation for Point of Common Coupling
    - All electrical equipment in Facility for stand-alone Energy Storage Systems

4.2.3 Protection Drawings

When protection schemes (not integrated to an inverter or controller) are used, the following additional drawings are required:

- Trip and Control elementary diagrams detailing what devices are tripped by protective devices

- AC Current and Voltage diagrams

4.2.4 Facility Equipment Specification Sheets

Manufacturer Technical Specification Sheets for installed equipment (e.g):

- Synchronous and Induction Generator Data Sheets
- Inverter Data Sheets with reference to Certifications from IEEE 1547 and UL 1741
- Backup Interfaces (i.e. Microgrid Interconnection Equipment)
- Customer owned transformation
- Protection and Control equipment
- Power Control Systems
- Power factor capability curve for each generator

4.2.5 Site Plan

Site plan detailing the Facility equipment and site infrastructure where the Facility will be installed. All equipment should have clear descriptive labeling and indicate if located inside or outside when appropriate. At a minimum, the following must be included when applicable:

- Utility service meter
- Production meters
- Electrical rooms
- Utility AC disconnect
- Generators/Inverters
- PV arrays
- Transformation
- Line extensions
- Point of Common Coupling
- Point of Interconnection
    - Utility pole number for stand-alone Facilities should be indicated
- Site Access (e.g.)

- Driveways
- Access Roads existing or to be built. Width of road should be indicated

- Site Identifiers (e.g.)
  - Address of Facility
  - Named roads
  - Property boundaries

4.3 Interconnection Studies

Each installation of DER is unique. Upon receipt of the interconnection application, the level of analysis and the need for detailed engineering study is determined by, among other things, the size and type of the proposed Facility, the character of service at the location of the Facility, and the inherent limitations of the transmission and distribution system. Any or all of the following Engineering analyses may be performed in response to a request for interconnection.

4.3.1 Facility Configuration

Facility rated output voltage must match System nominal operating voltage at the Point of Common Coupling.

Facility capacity must not exceed System capacity or jeopardize the integrity of System protection or controls.

Transformer winding configurations and grounding methods will be analyzed for compatibility with Company EPS.

4.3.2 Steady State Analysis

Steady State analyses will demonstrate compliance with applicable voltage and thermal loading criteria. For the purposes of this analysis, Facilities with a limited import/export will be reviewed at their limited capacity provided they meet the requirements of section 3.2.11.

No DER will be assumed as "must run" as a condition for acceptable operation of the Facility.

System equipment ratings shall not be exceeded during reverse power flow resulting from partial circuit load reduction caused by the opening one or more reclosers, sectionalizers or fuses on the same circuit.

Load levels and resource capability to be evaluated:

Peak load: Load will be modeled at 100% of the projected peak system load for the year the generator is projected to be in service with the output at full capability or the actual peak load experienced from the year prior. 10 Year projected peak system load forecasts may also be used subject to the Facilities operating parameters (e.g. ESS charging from Utility).

Light Load: Load will be modeled at 25% Peak Load.

Daytime Light Load: Specific to analysis of PV systems, the Daytime Light load will be used and calculated as 30% of the Peak Load.

4.3.3 Protection and Short Circuit Analysis

Protection studies will demonstrate that the sensitivity of fault detection of the existing line protection is not substantially degraded, the existing speed of fault clearing is not substantially degraded, and the existing coordination margin between relays is not decreased.

Short Circuit analyses will demonstrate that short circuit duties will not exceed equipment capability. All generating units will be assumed in-service and modeled at full nameplate rating of the generator. Export limiting schemes are not considered for short circuit analysis.

Existing non-directional line relays must not operate for faults external to the line due to the generating facility's current contribution to the fault.

System equipment ratings and settings shall not allow mis-coordination between System Operation and Facility protective devices and controls.

4.3.4 Stability

Stability studies, when required, will demonstrate that stability is maintained for all reasonable conditions and that un-damped oscillatory responses are not created between generation resources.

Power Flows across applicable transmission lines or interfaces should be at or below the most limiting of the existing stability or thermal transfer limits.

Reasonable combinations of resources and devices that would be expected to have significant interactions will be considered.

Load levels to be evaluated at full capability of the new resource:

Peak load: Load will be modeled at 100% of the projected peak system load for the year the generator is projected to be in service with the output at full capability or the actual peak load experienced from the year prior. 10 Year projected peak system load forecasts

may also be used subject to the Facilities operating parameters (e.g. ESS charging from Utility).

Light Load: Load will be modeled at 25% Peak Load.

Daytime Light Load: Specific to analysis of PV systems, the Daytime Light load will be used and calculated as 30% of the Peak Load.

4.3.5 Risk of Islanding

Anti-Islanding analyses will demonstrate compliance with applicable anti-islanding criteria in IEEE 1547 such that no Facility will exceed two seconds of run on time while in an islanding condition.

Facilities larger than 100kVA will be screened for Risk of Islanding and may be required to install advanced protection schemes (Direct Transfer Trip) preventing islanding conditions if screening fails. Screening will be performed using assessment guidance from Sandia Labs for unintentional islanding risk. If the Facility fails screening, a dynamic Risk of Islanding study will be offered to further assess the potential risk of islanding and need for a Direct Transfer Trip system.

4.3.6 Facility Grounding Analysis

Facility Grounding analyses will demonstrate compliance with IEEE 1547 effective grounding criteria such that no Facility will cause over voltages that exceed equipment ratings or disrupt the coordination of ground fault protection on the EPS.

Facilities larger than 250 kVA are required to go through a Facility Grounding Analysis.

4.3.7 Transmission System Impact Study

On a case-by-case basis, a Transmission system Impact Study may be required. The Company will assist in coordinating this study with the Transmission Owner to the extent necessary. All costs related to a Transmission System Impact Study are the responsibility of the Interconnecting Customer.

4.4 Company EPS Upgrade Requirements

The Company has requirements to upgrade Company EPS equipment when a DER Facility introduces the potential to reduce the reliability, effectiveness, or operational safety of existing electric distribution system or Company equipment. The following list is not all inclusive:

4.4.1 Single Phase Protection

Existing single-phase fuses and single-phase line switching devices may be installed between the Company substation and the generator interconnection.

Such devices may result in the loss of potential on one or more phases when operated, thus causing current and voltage unbalances at the point of interconnection. The Company may require the installation of a device capable of three-phase tripping to replace single phase protection if it is determined the Facility is unable to see and trip for faults due to the Facilities design.

4.4.2 Live Line Recloser Blocking

The Company EPS is generally equipped with relaying to provide automatic reclosing in the event of interruption. A Live Line Reclose Blocking scheme is intended to utilize voltage supervision to prevent the closing of a breaker or recloser onto a line that is being energized by DER. If it is determined there is potential for the Facility to energize a de-energized line, live-line reclose blocking may be added to the source recloser(s) or any midline recloser between the DER and the source, to inhibit manual or automatic closing of the Company equipment to an energized line.

4.4.3 Transmission Ground Fault Overvoltage Protection (3V0)

At the Company's Delta/Grounded Wye supply transformers, over voltages on unfaulted transmission phases may occur during line to ground faults on the transmission system. If it is determined there is potential for the Facility to pose significant risk of causing temporary over-voltage conditions to develop on the transmission system during line to ground faults, a ground overvoltage protection scheme will be installed at the substation.

4.4.4 Reverse Power Flow Equipment Capability

If the Facility causes reverse power flow conditions on the Company EPS, all relevant Company equipment impacted on the line sections that will have diminished functionality in the reverse power flow direction shall be upgraded for bi-directional capability if not already equipped (e.g. regulator controllers).

4.5 Interconnection Cost Estimates

Upon completion of all necessary engineering analyses, a facilities study will be conducted if additions or changes to the Company EPS are necessary to enable the interconnection of the DER Facility to the Company EPS. This study will identify the minimum upgrades to the Company EPS necessary to eliminate constraints, address protection or short circuit concerns, and/or to restore dynamic or steady state operating conditions to acceptable limits. The Interconnecting Customer will be notified in writing of any required Company EPS modifications and the estimated cost of those modifications. In addition to the Company EPS modifications, other affected parties, such as the Transmission Owner, may require modifications to their system. The Company will assist in communicating those cost estimates to the Interconnecting Customer if applicable.

4.6 Changes to the Interconnection Application

During the interconnection process the Interconnecting Customer may request to make changes to their interconnection application. The Company will assess the scope of change request to determine whether the change is Significant or Moderate. A change request deemed to be Significant by the Company will require a new interconnection application. The following defines these terms and the associated impacts to the DER application.

Significant Change: A change is considered Significant if it meets **EITHER** of following criteria:

1. Interconnecting Customer Impact: Results of studying the change may have an adverse impact to other Interconnecting Customers that are in queue at the time the change is requested.

   OR

2. Engineering Impact: The change modifies the fundamental design intent of the original application to such an extent that majority of the engineering analyses of the original SIS must be re-performed (ex. load flow, protective device analyses, substation assessment, etc).

Examples of Significant changes include, but are not limited to:

- Adding new DER technology not in original design (ex. adding AC coupled ESS)
- Physical relocation of POI to feeder location with different electrical characteristics (ex. different feeder, or different location relative to recloser, capacitor, etc)
- Any increase in nameplate rating or total export capacity of the facility
- Change to BESS charge/discharge schedule
- Change to BESS charging method/source (ex. grid charging vs PV charging)
- Change in Market participation, causing a change to site design
- Change in interface transformer winding configuration (Delta or Wye)
- Change in grounding configuration
- Changes that affect any ASO analyses

Moderate Change: A change is considered Moderate if it meets **BOTH** of the following criteria:

1. Interconnecting Customer Impact: The change has no possibility of impact to other Interconnecting Customers. Either confirmed through the fact that no other applications are after the subject project in queue or confirmed by engineering review of the proposed change.

   AND

2. Engineering Impact: The change modifies the original application requiring limited performance of engineering analyses of the original SIS to be re-performed (ex. load flow, protective device analyses, substation assessment, etc).

Examples of Moderate changes include, but are not limited to:

- Inverter manufacturer change
- Adjustment to transformer impedance
- Recloser setting adjustment

4.7 Facility Inspection and Testing

After the construction of the Facility is complete, the Company has received a Certificate of Completion signed by the local authority responsible for electrical inspection, and applicable Company EPS modifications are complete, the following requirements must be satisfied prior to the Facility receiving approval to operate.

4.7.1 Facility Inspection

After installation the DER Facility must be inspected and accepted by a qualified Company representative. The Company may elect to waive this inspection in lieu of alternative verification at the discretion of the Company. In addition, the Company may require a letter from the Interconnecting Customer certifying the as-built Facility was constructed per the Facility design approved by the Company.

4.7.2 Customer Protection System Testing

For all Facilities incorporating non-Certified DER and all Facilities larger than 500kW, The Interconnecting Customer will provide a certified relay test report documenting the Protection System has been calibrated and all relay functions reviewed and approved by the Company are programmed and functioning correctly. Additionally, the Company may elect to perform their own testing of the Protection System if deemed necessary.

Relaying which serves only to protect the Customer's equipment and is not specifically required by the Company may be excluded from this testing at the discretion of the Company.

4.7.3 Witness Testing

At the discretion of the Company the DER Facility may be required to perform a commissioning test witnessed by the Company. The Interconnecting Customer must provide the testing procedure to the Company for review and approval. At a minimum, the testing procedure must include the following:

- A complete functional test of the Protection System if not satisfied by section 4.7.2.
- In service functional testing of the DER to include:
  - Settings verification
  - Reconnect Test
  - Shutdown Test
  - Power Flow verification

4.7.4 As-Built Drawings

The Interconnecting Customer shall supply the Company with as-built drawings with sufficient information to safely perform, review and/or interpret the functional test results.

4.8 Replacement to in service DER Equipment

If individual equipment of in-service DER facility requires replacement due to failure or condition, the DER system owner must notify the Company of the equipment to be replaced per the State specific notification process.

5.0 Disclaimer

The Company’s review of the Interconnecting Customer's facility, equipment, interconnection equipment, protective devices and metering, shall not be construed as confirming or endorsing the design, or as any warranty of safety, durability or reliability of the facility or any of the equipment.

The Company shall not, by reason of such review or failure to review, be responsible for the strength, safety, adequacy or capacity of the Interconnecting Customer's facility, equipment, interconnection equipment, or protective devices, nor shall the Company’s acceptance be deemed an endorsement of such facility or of any equipment or details of design.

The Interconnecting Customer must agree to change its facility, equipment interconnection equipment, or protective devices as may be reasonably required by the Company to meet changing requirements of the Company's system.

Nothing contained in this guideline is intended to replace or supersedes any requirement of the Independent System Operator (ISO New England). Customer-generators will be required to comply with all applicable ISO New England information requests, rules and requirements that are necessary to interconnect the generating facility to the electric system.

5.1 Exceptions

While this document is intended to address the requirements of most DER installations, it is recognized that this, or any similar document, cannot cover every possible contingency or variation in equipment to be encountered at the various DER installations.

The Company will address, on a case-by-case basis, DER installations with unique or special requirements not covered elsewhere in this document.

6.0 Interconnecting Customer Responsibilities

6.1 Company Approval

No DER, no matter its intent, shall be installed or operated in parallel with the Company EPS without prior notification to and approval by the Company.

This responsibility applies to an initial Facility, as well as to subsequent additions and/or modifications of Facility equipment or change of ownership through sale. The Interconnecting Customer is responsible for modifying their system to comply with any future mandate of the Regional ISO; NPCC; and NERC or successor organizations including cost incurred.

If the Interconnecting Customer makes significant changes in the design or scheduling of the project, then any previous information furnished by the Company to the Generator-owner shall be subject to review and possible change. Failure to communicate such changes to the Company may result in delay of service or termination of service by the Company.

The Interconnecting Customer is responsible for maintaining Company specified telecommunication equipment and services as required for the installation.

6.2 Protection of Customer Owned Equipment

The Interconnecting Customer is responsible for protecting Facility equipment in such a manner that faults or other disturbances on the Company's system do not cause damage to the Interconnecting Customer's equipment.

The Company will not assume responsibility for protection of DER Facilities or of any other portion of the Customer's electrical equipment.

6.3 Maintenance and Testing

The Interconnecting Customer is responsible for the maintenance and testing of all interconnection equipment, including power apparatus and the interconnection relay system.

Periodic tests should be performed according to the manufacturer's recommended test guidelines and, at a minimum, shall be performed in accordance with the Company's relay maintenance procedures.

Specific relay test data shall be made available to the Company upon request to provide evidence that each relay will operate as desired.

Failure of the Interconnecting Customer to provide proper testing and maintenance will result in the Interconnecting Customer being notified and requested to take prompt corrective action within ten (10) days.

Should the Interconnecting Customer then fail to provide proper testing and maintenance within the ten days, parallel operation may be required to cease until appropriate corrective action is taken and Company approval is obtained.

The Interconnecting Customer shall bear the cost of any necessary testing that may be requested by the Company. Such testing may be required as a result of a malfunction of a component of the protective system, accidental damage to parts of the protective system, or the like.

6.4 Compliance and Notification

DER must not operate interconnected to the Company EPS if any equipment, relays or protection schemes specified by the Company are not in-service or are not functioning correctly.

The Company is to be made aware, immediately, of any protective relay that is found to be defective if not replaced immediately by a duplicate, operable device.