Massachusetts Technical Standards Review Group

# Common Technical Standards Manual

To accompany M.D.P.U. No. 1468

# 1.0 Table of Contents

# 2.0 Introduction

Massachusetts Electric Company and Narragansett Electric Company, each d/b/a National Grid ("National Grid"), NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource"), and Fitchburg Gas and Electric Light Company d/b/a Unitil (collectively referred to as the "Utilities"; individually referred to as "Utility"), with input through the Massachusetts Technical Standards Review Group ("TSRG")[1], developed this Common Technical Standards Manual ("Manual")[2] as a reference guide to identify areas of commonality and difference among the Utilities with regard to each of their technical standards and requirements for the interconnection of distributed generation ("Interconnection Requirements") and to provide additional technical clarification of some Utility-specific Interconnection Requirements. This Manual is subject to each Utility's uncontroverted ability to continue to apply a Utility-specific Interconnection Requirement that deviates from a common Interconnection Requirement followed by one or more of the other Utilities. Further, each Utility reserves the right to deviate from this Manual when, in its sole discretion, it determines it is necessary to do so. This Manual only addresses each Utility's Interconnection Requirements applicable in The Commonwealth of Massachusetts.

The Manual is intended to serve as a reference tool only for a distributed energy resource ("DER") interconnecting customer. The interconnecting customer must refer to the documentation referenced or provided by each Utility to determine the Utility's specific interconnection standards and requirements, as well as each Utility's interconnection tariff. Links to each Utility's Interconnection Requirements are provided for convenience at Section 2.1 below and can be accessed on each Utility's website. To the extent there is any conflict between this Manual and a Utility-specific Interconnection Requirement, the Utility specific Interconnection Requirement will take precedence over the Manual. This Manual is not all inclusive of the Interconnection Requirements and there may be Interconnection Requirements in addition to those addressed in this Manual applicable to any specific DER facility.

The Utilities have the absolute right to update and revise this Manual. Any revisions of this Manual will be provided to the TSRG and be made available on the Department of Energy Resources ("DOER") website.[3]

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[1] In its Final Report to the Department of Public Utilities ("Department"), the Massachusetts Distributed Generation Interconnection Working Group, as established in D.P.U. 11-75, recommended the creation of a Technical Standards Review Group ("TSRG") to further address interconnection issues.

[2] This Manual was developed pursuant to the Massachusetts Distributed Generation Interconnection Working Group Final Report. *See Final Report, p. 30.*

[3] Provided, however, neither notice to the TSRG or such posting is required prior to implementation of any Utility Interconnection Requirement.

This Manual refers only to each Utility's Interconnection Requirements, and it shall be the interconnecting customer's sole responsibility to ensure that the DER facility meets all applicable federal, state, and local, codes, rules, regulations, and laws.

# 3.0 Standards and Guidelines Reference

The following represents a list of electric distribution company (EDC) requirements and Department of Public Utilities (DPU) direction relative to distributed generation (DG)interconnections in Massachusetts. This is not intended as a comprehensive listing of all applicable requirements and considerations that a DG customer must consider. Instead this is a general listing to assist those customers in awareness of general requirements. It is the responsibility of any stakeholder engaged in the interconnection process to understand processes and technical requirements of an interconnection.

## 3.1 Electric Distribution Companies

The following documentation should be referenced on a Utility-specific basis. The documents are Company standards or official guidelines pertaining to the parallel connection of distributed generation to the electric power system and the requirements therein take precedence over this document.

**Eversource**

**Technical Specifications for Distributed Generation Interconnection**
https://www.eversource.com/content/docs/default-source/builders-contractors/der-information-technical-requirements.pdf?sfvrsn=ab2bfc62_10

**National Grid**

**ESB 756, Requirements for Parallel Generation, Appendix C-Massachusetts**
https://www.nationalgridus.com/media/pronet/shared_constr_esb756.pdf

**Other National Grid standards incorporated into ESB 756 by reference**

https://www.nationalgridus.com/pronet/technical-resources/electric-specifications

**Additional Guidance Documents**

https://ngus.force.com/s/article/MA-Interconnection-Documents

**Unitil**

**Distributed Generation Interconnection Standards**
https://unitil.com/sites/default/files/2021-03/Unitil Guideline for Interconnecting DG GL-DT-TC-10.pdf

## 3.2 Department of Public Utilities

Refer to the DPU websites below for information.

- Interconnection:
  - https://www.mass.gov/info-details/interconnection-filings-and-tariffs
- Net metering:
  - https://www.mass.gov/info-details/net-metering-filings-and-tariffs
- Qualified Facilities:
  - https://www.mass.gov/info-details/qualifying-facilities-and-on-site-generating-facilities
- SMART Program:
  - https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program#open-proceedings-
- Provisional System Planning Guidelines:
  - https://www.mass.gov/guides/provisional-system-planning-program-guide

# 4.0 Anti-Islanding, Reclose Blocking, and Direct Transfer Trip

In the event that a portion of the utility electric system is electrically separated from the rest of the electric system, a Facility on that section of the system could possibly island with the load on that section, such that insufficient anti-islanding provisions at the Facility could lead to run-on times beyond the two-second limit prescribed in IEEE 1547. This could result in safety risks to line workers and the public, as well as equipment damage and reliability and power quality risks. Amongst all utilities, for cases where the line section aggregated DER is ≤ 33% of minimum load, regardless of DER type mix, the risk of islanding (ROI) is considered negligible and no further screening is required. Each utility also reviews multiple line sections that the facility may be capable of islanding.

In this section Direct Transfer Trip is defined as protection scheme designed to automatically separate the Facility from the EPS via a remote (or loss of remote) signal from the utility by tripping one or more breakers at the PPC or within the Customer's Facility.

All risk of islanding studies, where applicable, are performed at the expense of the applicant.

## 4.1 Screening Process

For all Interconnection Applications, each Member Utility screens the Facility for potential islanding conditions.

***Eversource:***

**ROI SCREENING PROCESS**

All Proposed DER projects > 100 kW will be reviewed. The line section minimum load to aggregate DER ratio will be determined. This can be accomplished during a preliminary application review or as part of the system impact study. Pre-existing DER equipped with direct transfer trip (DTT) may not be factored into any aggregate DER screens identified within this document. DER at customer sites equipped with reverse power or minimum import relays should also be evaluated to determine the appropriate contribution to aggregate capacity screens.

If any line section has an aggregate DER-to-minimum load ratio >33%, the following evaluation is performed.

**CERTIFIED DER**

<u>Line section aggregated non-certified DER is ≤ 10% of the mix **and** DER ≤ 2000 kW</u>
No additional requirements related to Risk of Islanding (ROI).

<u>Line section aggregated non-certified DER is > 10% of aggregate DER **or** DER > 2000 kW.</u>
Sandia screening (see Appendix C) shall be performed. Note - when insufficient data exists to perform a complete VAR balance review, Sandia screen #2 shall be considered a failure.

If Sandia screens are passed, no additional requirements related to ROI are enforced.

If Sandia screens are not passed, a dynamic risk of islanding study (D-ROI) may be offered. If the D-ROI study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the D-ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA-enabled recloser or other isolation device at the PCC is required. Reclose blocking of upstream devices will be evaluated. DTT may also be required (see Note 1).

**NON-CERTIFIED INVERTERS, INDUCTION & SYNCHRONOUS MACHINES**

A dynamic risk of islanding study (D-ROI) may be offered. If the D-ROI study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the D-ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA-enabled recloser or other isolation device at the PCC is required. Reclose blocking of upstream devices will be evaluated. DTT may also be required (see Note 1).

<u>Note 1</u>
In addition to a site recloser and the implementation of reclose blocking, Eversource reserves the right to require direct transfer trip (DTT) for projects with unique characteristics that create a high risk of islanding, either under existing or future circuit conditions. In those cases, Eversource will determine whether a detailed risk of islanding (ROI) study is warranted. If sufficient data is available to conduct a robust ROI study, and the results are reasonably

expected to create information that may alleviate Eversource's concerns, the interconnection customer will be offered the opportunity to proceed with a detailed ROI study. If results of that study show no significant risk of islanding under all operating conditions for a period greater than 2 seconds, then Eversource will consider waiving the DTT requirement.

**SPECIAL CONDITIONS**

The following are conditions where additional EPS protection schemes, including but not limited to direct transfer tripping (DTT), may be required. These conditions may exist independent of the above ROI evaluation results.

- •If line faults (phase and ground where applicable) cannot be cleared by DER protective device or Eversource owned PCC recloser.
- •Unique arrangements not explicitly defined within this document at Eversource's discretion. This includes a consideration of off-normal circuit configurations.
- •DER that cannot be tripped off with utility-owned devices when automated sectionalizing schemes operate.
- •DER that cannot be tripped off within 2 seconds following the formation of an island, as this poses a risk to our customers and hinders operation of automated sectionalizing and restoration schemes.

## National Grid:

National Grid generally does not require DTT for inverter-based UL1741 listed generators that do not regulate voltage, and instead requires reclose blocking where the aggregate generation on each line section does not pass the Sandia report screens. A Risk of Islanding study may be performed for inverter-based DER at the Customer's request. A complete distribution feeder may contain multiple line sections. Depending on the aggregate DER size to load ratio, multiple line sections may require review and be screened accordingly per the steps outlined. Each screen is repeated for each line section applicable to the proposed DER. Where DTT or reclose blocking is required based on the screens, it shall be applied at the sectionalizing device for that line section. A utility owned recloser is required where aggregate line section DER ≥ 300 kW and DER > 33% minimum load and is connected to < 5 kV EPS.
The Company may reclose at any distribution EPS segment at any time without checking for de-energized segments as normal system operations to maintain service reliability. It is important to the DER operator to be aware of this possibility as it is the responsibility of the DER operator to trip off within 2 seconds in the event the EPS utility source is not present.
Rotating machines and voltage regulating inverters require DTT if they meet or exceed 33% of the minimum load.

The screens are as follows:

**Certified DER**

1. All inverters shall have an 88% voltage trip within 2 seconds to be considered in this section.
2. Proposed DER rated ≤ 50 kW
    a. No requirements.
3. Proposed DER rated > 50 kW and < 1000 kW
    a. Line section aggregated non-certified DER is ≤ 10% of mix.
        i. No additional requirements.
    b. Line section aggregated non-certified DER is > 10% and ≤ 25% of aggregate DER.
        i. Sandia screening[4] may be applicable depending on inverter models on segment.
        ii. Company-owned PCC recloser and reclose blocking required if Sandia screens not passed.
            1. Detailed risk of islanding (ROI) study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then the recloser and reclose blocking is waived.
    c. Line section aggregated non-certified DER is > 25% of all DER.
        i. NG PCC recloser and reclose blocking required[5]
            1. Detailed ROI study may be performed at the Customer-Generator's request. If results of the detailed study show no significant risk of islanding for a period greater than 2 seconds, then reclose blocking is waived. Company-owned PCC recloser is waived for aggregate DER ≤ 67% of line load to generation ratio or < 500 kW.
4. Proposed DER rated DER ≥ 1000 kW
    a. Company-owned PCC Recloser required.
    b. Reclose blocking required if line segment aggregate DER > 50% of minimum load.

**Non-certified & voltage regulating inverters, induction & synchronous machines**

1. Require ANSI C37.90 utility-grade protective relay with IEEE 1547 voltage and frequency tripping and restoration functions.
2. Total aggregate line section DER > 33% minimum load
    a. DTT required.

**Direct Transfer Trip may be required for the following:**

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[4] *The Sandia screens ([http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf](http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf)) are valid only for those certified inverters that have been confirmed, in writing from the manufacturer, to meet the definition of the Sandia Frequency Shift (SFS), or Sandia Voltage Shift (SVS) as positive feedback based methods according to the report or for inverters using impedance detection with positive feedback. SFS and SVS both rely on positive feedback to work.*

*Positive feedback – detecting a deviation in grid parameters and acting to try to make that deviation from nominal worse. Where acting to try to make that deviation worse, the perturbations must push harder as the deviations from nominal increase. The algorithm must be able to push bi-directionally in order to be considered for this screen.*

[5] *Where feasible, installing a PCC recloser in front of the non-certified DER may reduce or eliminate any further requirements to the subject applicant DER.*

1. Cases where additional EPS protection schemes, including but not limited to transfer tripping, may be required[6]
   a. If line faults (phase and ground where applicable) cannot be cleared by DER protective device or the Company's PCC recloser.[7]
   b. Unique arrangements not explicitly defined within this document at the Company's discretion.
   c. If the DER cannot be tripped off with utility-owned devices when automated sectionalizing schemes will operate.
   d. DER connected to > 35 kV EPS where DER > 50% onsite minimum load and the connecting line is radially supplied.

## Unitil

During supplemental review and Impact Studies, DER applications that are larger than 100kW are screened for potential anti-islanding by load to generation ratio at each device location that could operate to form an island boundary (Line Section). Pre-existing DER equipped with direct transfer trip (DTT) may be removed from the aggregate generation for this screening process. For projects that fail the anti-islanding screening, Unitil requires a Direct Transfer Trip scheme be installed or offers to conduct a detailed Risk of Islanding study. The screening tools vary by type of DER technology, and are as follows:

If any line section has an aggregate DER-to-minimum load ratio >33%, the following evaluation is performed.

**CERTIFIED DER**

Line section aggregated non-certified DER is > 10% of aggregate DER **or** DER > 2000 kW.
Sandia screening shall be performed. Note - when insufficient data exists to perform a complete VAR balance review, Sandia screen #2 shall be considered a failure.

If Sandia screens are passed, no additional requirements related to ROI are enforced.

If Sandia screens are not passed, a DTT scheme is required or a dynamic risk of islanding study may be offered. If the dynamic risk of islanding study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

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[6] *While the intent of this unintentional islanding protection policy is to encourage DER installations while minimizing inhibitive impacts to the DER installation, National Grid reserves the right and flexibility to enforce protective measures deemed required for the safety and reliability of the EPS.*

[7] *Customers should be aware that >15kV class circuits typically involve more complex protection schemes, which can be more likely to require DTT due to inability to see and trip faults in an acceptable time frame, in addition to operational issues that may be present at these voltage classes (23kV and 34.5kV).*

If the a dynamic risk of islanding study is either not offered, is declined by the applicant, or has unacceptable results, then a Company owned, SCADA-enabled recloser or other isolation device at the PCC and DTT is required .

**NON-CERTIFIED INVERTERS, INDUCTION & SYNCHRONOUS MACHINES**

A dynamic risk of islanding study may be offered. If the a dynamic risk of islanding study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the a dynamic risk of islanding study is either not offered, is declined by the applicant, or has unacceptable results, then an Unitil owned, SCADA-enabled recloser or other isolation device at the PCC is required. DTT may also be required

## 4.2 Reclose Blocking

The joint utilities may require reclose blocking (voltage supervised closing) where DERs are installed on the load side of an automated interrupting device. This may include substation interrupting devices and/or reclosers on distribution circuits.

**National Grid Only:** Reclose blocking may be required in lieu of DTT for certain UL1741 inverter-based systems per the screens in section 4.1.

## 4.3 Direct Transfer Trip

Direct transfer trip schemes may be required by the Joint Utilities to ensure safe and reliable operation of the Area EPS. The Joint Utilities require direct transfer trip as definitive means of anti-islanding detection. The scheme will be driven by a signal (or loss of signal) sent by the Member Utility and received and acted upon by equipment designated by the Member Utility to isolate the generator from the Area EPS. The communication medium required to install the transfer trip scheme may vary due to application. The installation and applicable monthly/maintenance cost of the communication medium is the responsibility of the Interconnecting Customer.

Other application cases may include, but are not limited to:

- N-1 system contingencies
- Off-schedule system configurations
- Any condition that may negatively affect system reliability or safety
- Mitigation of out-of-step reclosing
- Adverse system conditions that cannot be adequately detected and corrected with protective relaying schemes local to the DER facility
- Conditions where the DER is unable to see and trip for faults adequately.

# 5.0 DER Capacity – Feeder Limits

In general, the Joint Utilities have no defined limits on DER capacity on individual feeders. Capacity issues will be considered as part of the Impact Study or Supplemental Review. A study will identify limits based on thermal load flow, voltage rise, reverse flow through equipment, and voltage flicker.

Larger amounts of generation may be interconnected at the expense of the Interconnecting Customer by reconductoring or replacing equipment on a feeder as necessary to accommodate the increased thermal loading. Larger generation can be interconnected to express feeders if proper cable size is used and feeder breaker is available

## 5.1 Minimum Feeder Load

Measurement and data acquisition of the minimum load on individual feeders can vary from utility to utility and feeder to feeder. When measurement data is not available, the minimum feeder load is defined as 25% of the maximum peak load over the previous 12-month period.

# 6.0 Remote Monitoring and Control

Each utility requires remote monitoring and control means for facilities of a certain threshold size. This remote monitoring and control (RMAC) is typically in the form of a Remote Terminal Unit (RTU) or direct communication to a measurement device, which provides status of the monitored quantities at the site and control of an interrupting device (such as a circuit breaker or recloser). Where the joint utilities require a utility-owned PCC recloser, these requirements may be met with that device for IPP facilities. Some facilities consisting of both load and generation at the same site may be required to have a remote monitoring and control device (such as an RTU or similar equipment) in addition to the recloser so that both the load and generation can be monitored and controlled separately.

## 6.1 Remote Monitoring and Control Threshold Requirements

The Joint Utilities may require the installation of dedicated RMAC equipment. The necessity for RMAC is based on Facility size and voltage class of the Area EPS. If the size of the Facility exceeds the thresholds for each utility, RMAC equipment is required. Each utility reserves the right to require the monitoring listed below depending on the site size and conditions.

Eversource**:**

A recloser may be required for all sites $\geq$500kW sites.

National **Grid:**

National Grid reserves the right to require RMAC equipment for any facility 250kW and larger depending on the individual project conditions. For IPP systems, National Grid generally does not require an RTU, regardless of size or voltage class. Where required, National Grid will remotely monitor and control IPP-based generation using the National Grid-owned PCC recloser. For non-IPP customers, National Grid will require an RTU according to table 2, in addition to any utility-owned recloser requirement.

**Table 1: RMAC (RTU) Requirement Thresholds for (non-IPP) Customers for National Grid**

| Area EPS Distribution Voltage Class | Facility Size |
|---|---|
| 5 kV or below | ≥ 500 kW |
| Greater than 5kV but less than 15 kV | ≥ 1,000 kW |
| > 15 kV and <69kV | ≥ 1,800 kW |

Unitil:

Unitil requires an RMAC for all Facilities ≥ 500 kVA. Unitil also requires real-time remote monitoring for each individual unit of 500 kVA or more, even if the interrupting device at the PCC is also being monitored.

## 6.2 Data Acquisition and Control

The RMAC (recloser and/or RTU) must allow each Member Utility to monitor the Facility's status and to allow for remote disconnection of the Facility from the Area EPS as system conditions require.

Typical information required to be monitored may include and is not limited to the following data points:

- Net real power (kW)
- Net apparent power (kVA)
- Net reactive power (kVAR)
- Instantaneous phase current magnitude(Amps) – all phases
- Phase-to-phase voltages (Volts)– all phases
- Frequency (Hz)
- Facility breaker status
- Fault targets (if applicable)
- Status of main or interconnect breaker at the point of common coupling (PCC)
- Status of individual generator breakers
- Control input for the "designated generator interrupting device" for trip, block close &
- permit close functionality

- Protective relay status (if applicable)
- DC Control System Status (if applicable)
- Other status points, as required

## 6.3 RMAC Communications

Generally, the Customer is responsible for the installation and maintenance costs of the communications medium. In addition to any RMAC, the utility-owned PCC recloser (if available) will be controlled by each Member Utility through existing utility communications mediums.

National Grid: MPLS communication line leased from local communication service provider.

Eversource:  MDS radio-based communication.

Unitil: Determined on a case-by-case basis.

## 6.4 Remote Operation

Where  an RMAC or recloser is required, remote tripping of the site must be enabled. This control is installed to disconnect the generation from the Utility EPS.

# 7.0 PCC Protective Device Requirements

## 7.1 Reclosers

The Joint Utilities require a utility-owned PCC recloser to be installed for all large Facilities. In general, the recloser requirement will be governed by the Facility sizes and voltage classes listed in Table 2. The Joint Utilities reserve the right to implement a recloser in any case it is deemed necessary to interconnect a Facility with the potential to cause an adverse condition.

**Table 2: PCC Recloser Requirement Thresholds**

| Area EPS Voltage Class | Facility Size | Recloser Required? | | |
|---|---|---|---|---|
| | | **Eversource** | **National Grid** | **Unitil** |
| ≤ 5 kV | ≥ 500 kW | Yes | Yes | Yes |
| ≥ 15 kV | ≥ 1,000 kW | Yes | Yes | Yes |

If it is determined that islanding is of concern per section 4.1, a recloser may be required by the Joint Utilities.

## 7.2 External Disconnects

External disconnects are required by the Joint Utilities. Each Member Utility has a different threshold for when an external disconnect is required, as detailed in Table 3. The switch shall at minimum provide a visible break, be lockable in the open position and be accessible by the utility 24/7 at all times of the year.

**Table 3: External Disconnect Requirement Thresholds**

| Member Utility | Facility Size |
|---|---|
| Eversource | All sizes |
| National Grid | ≥ 25 kW[8] |
| Unitil | > 10 kW |

# 8.0 Witness Test Protocols

Witness testing is required for all facilities, but may be waived for simplified and some expedited projects using UL1741 certified inverters at the discretion of the utility. Witness tests are required for all sites that require a utility-grade protective relay.

[8] If the unit is UL 1741 Listed inverter-based and has a disconnecting means integrated into the design and meets the requirements of the National Electrical Code (NEC), an additional external disconnect may not be required below 25kW.

## 8.1 General Requirements

During a Witness Test, each Member Utility inspects the completed Facility for compliance with the interconnection requirements. The Customer will provide a proposed Witness Test procedure and all requisite supporting documentation for review by the Member Utility once the Customer has completed the installation of the Facility.

Utilities generally require utility grade relay redundancy for sites 500kW or greater. Smaller facilities that are not using certified generators also require a witness test for the utility grade relays. Where UL1741 certified generation is accepted for utility grade relaying, testing of generator internal relaying, as well as certification by a nationally recognized testing laboratory that employs UL 1741 testing standards is required. A witness test may be required on a case-by-case basis for all facilities, including storage.

The witness test must be conducted by a third party, and attended by a Member Utility representative for supervision and approval of results.

## 8.2 Witness Test Procedures

Each witness test shall include both a calibration check and an actual trip of the circuit breaker or contactor from the device being tested. Visually setting a calibration dial, index, or tap is not considered an adequate calibration. Testing typically includes, but is not limited to:

- CT and CT circuit, polarity, ratio, insulation, excitation, continuity, and burden tests (excitation test results may be submitted prior to the witness test for most facilities).
- VT and VT circuit, polarity, ratio, insulation and continuity tests (results may be submitted prior to the witness test for most facilities).
- Relay pick-up and time delay tests (In some cases a certified testing letter may be acceptable, provided the test results include polarity and ratios for instrumentation devices).
- 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 interlocks tests
- Paralleling and disconnection operation
- Anti-islanding function (if applicable)
- Non-export function (if applicable)
- Synchronizing controls (if applicable)
- Proof of inability to energize de-energized lines and 5-minute reconnect time

- Proof of fail-safe relay design (where all relay functions may not be fully redundant)

## 8.3 Documentation

It is the Customer's responsibility to prepare all witness testing documents and procedures with sufficient time for review by the utility prior to scheduling the witness test. At a minimum, the following documentation is required:

- Witness test procedure
- Energization plan
- Current PE-stamped single-line diagram
- Relay settings
- Relay bench test results (if applicable)
- Current and Voltage Transformer Test Reports.
- Letter of Completed On-site Testing from Test Company
- Transformer test report (if applicable)

## 8.4 Testing Points

Relay set-points should be specified in accordance with utility requirements and IEEE 1547. Under-frequency ride-through should be modified according to the NPCC A.03 curve.[9] Clearing times include breaker operation. At a minimum, the following relay functions shall be tested during the witness test:

- 27 Under-voltage
- 59 Overvoltage
- 81O Over-frequency
- 81U Under-frequency
- 51N Neutral Overcurrent (where applicable)
- 51 Phase Overcurrent (where applicable)
- 51C Phase Overcurrent (voltage-controlled, where applicable)
- 59N Neutral Overvoltage (where applicable)
- Breaker Failure (where applicable)

The Joint Utilities may require additional protections not listed here depending on the site configuration.

[9] New England ISO may update ride through and tripping requirements for DERs.

### 8.5 Failure Protocol

In the event that a Facility fails a witness test (i.e. test results of a relay function fall outside of a certain tolerance), the witness test will be rescheduled, and the failed elements will be retested.

## 9.0 Power Factor

All Facilities are required to maintain a pre-determined static power factor. Typically each utility requires unity power factor operation at the generator device terminals, but may require off-unity depending on site conditions. Equipment may be required to be installed at the Facility if the generator source is unable to meet the specified power factor. Active voltage regulation may be permitted on a case-by-case basis.[10]

## 10.0 GSU Transformer Winding Configurations

With few exceptions, the Joint Utilities maintain multi-grounded systems, and the Customer's generation step-up (GSU) transformer winding configuration must be compatible with the Area EPS. In all service territories, neutral grounding reactors or resistors (NGR) may be required in the event that utility grounding fault detection is compromised by the addition of the Facility. Each Member Utility maintains a handful of ungrounded circuits, for which alternate winding configurations may be acceptable. However, for standard, four-wire, multi-grounded circuits, the acceptable transformer configurations are shown in Table 4.

**Table 4: Permitted Transformer Winding Configurations for Multi-Grounded Circuits**

| Primary (Utility) | Secondary (Customer) | Added Requirements |
|---|---|---|
| Wye-grounded | Delta | NGR (if necessary) |
| Wye-grounded | Wye-grounded[11] | Effectively grounded DER source |
| Wye-grounded | Wye-grounded[11] | Secondary grounding transformer |

National Grid only may also permit a delta primary transformer or ungrounded connection if a primary-side grounding transformer is added.

[10] Active voltage regulation may require direct transfer trip per section 4.1.
[11] Assumes high magnetizing impedance for 3-legged core-type transformers.

# 11.0 Utility Grade and Redundant Relaying

For all Facilities with a capacity of 500 kW or greater, the Joint Utilities require redundant utility-grade relaying to disconnect the Facility under faulted conditions. In addition, redundant relaying may be required for Facilities with a capacity of 250 kW or greater depending on site conditions. Utility-grade relaying is required for all synchronous and/or non-UL1741 certified generators. The Joint Utilities reserve the right to require redundant relaying for any installation in order to maintain safety and reliability.

The location of the relaying is determined by the location of the generator grounding source (e.g. based on the transformer winding configuration, generator grounding, or location of grounding banks). Upon approval, protection functions provided by a Member Utility-owned recloser at the PCC may be considered as providing redundant relay functionality. Customer-owned relays must be located on the utility side of the grounding source, if applicable, on the customer side of the PCC. For a list of required relays, refer to the Witness Test Section 8.0.

# 12.0 Substation Reverse Power Flow

The Joint Utilities permit reverse power flow through the substation supply transformers, although System Modifications may be required to do so.  Any proposed Facility that has the potential to cause reverse power flow through a substation transformer will require a System Impact Study (SIS). The SIS will specifically address the ability of the transformer to accommodate reverse power flow. During the SIS, the following items will be evaluated.

## 12.1 System Voltage Control

System voltage control includes load tap changers or voltage regulators. The SIS determines if system voltage control can be maintained at various boundary conditions, and will evaluate excessive controller operation caused by intermittent DER sources. The SIS will also evaluate the capability of the controller to accommodate reverse power conditions and to respond with appropriate control strategies.

Voltage and current inputs must be available to the system voltage controller. Any controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs. The requirement to add a backup controller will also be evaluated. Controller upgrades may be required system modifications resulting from DER facility interconnection.

Controller settings will be determined on case-by-case analysis of DER type and penetration.

### 12.2 Capacity Limit

Intermittent reverse power flow will be permitted up to a level consistent with each Member Utility's standards for transformer loading. The reverse power flow limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer. Reverse power flow that will significantly add to the transformer insulation loss of life on a routine basis, based on the transformer specification and the insulation aging description in the latest version of IEEE Std. C57.91, will be evaluated. Any required transformer upgrades will be included in system modifications required to interconnect the DER Facility.

DER Facilities must supply a balanced three-phase output such that there would never be a situation where a substation transformer could experience forward power flow on one or more phases while experiencing reverse power flow on the other phase(s).

### 12.3 Transmission Ground Fault Protection

For situations where the total DER on the substation is approaching the minimum load of the substation, reverse power flow and the likelihood of the DER being able to sustain overvoltage conditions in the event of a single line to ground fault on the high side of the substation transformer are of concern. In these instances, zero-sequence overvoltage relaying (59N) is required on the high-side of the supply transformer (if delta or otherwise ungrounded) to detect and trip the DER's contribution to transmission ground faults. In instances where primary instrumentation transformers are not viable, DTT may be used to disconnect the facility for transmission faults.

## 13.0 Simplified Spot and Area Network Interconnections

For all UL 1741 Listed Inverter-based Facilities connecting to a Spot or Area Network that have a total nameplate rating less than 1/15 of the Customer's minimum load and 15kW or less qualify of for the Simplified interconnection track per the interconnection tariff. Facilities that do not qualify for Simplified interconnections require a study per the Standard process.

## 14.0 Voltage Flicker

During the Expedited Review process, voltage deviations of greater than 2.0% will prompt the application to be moved to a full System Impact Study.

# 15.0 Detailed Study

The Detailed Study from each utility follows the requirements of the tariff. Each utility provides an Estimated Project Construction Schedule/Duration which will include a description of major milestone items, duration of each milestone item in weeks, and responsible party for that item.

In general, unless otherwise noted on the schedule, milestone items are assumed to be sequential, in that one must be completed before the next may proceed. Delays at any one milestone item, including but not limited to, weather, force majeure, customer response, transmission outage requirements, or other unforeseen circumstances outside of utility control will result in delay of total project time line. The information included is on a case-by-case basis for the project as determined by the results of the detailed study and are subject to each utility's construction terms and conditions.

# 16.0 Energy Storage Systems (ESS)

The Joint Utilities generally permit interconnection of energy storage systems to their infrastructure. The following section identifies further details surrounding the interconnection of ESS. Where practices differ amongst the Joint Utilities, individual utility position is listed below, with explanation as to the need for the differentiation.

## 16.1 Technical Analyses

Load flow simulation and protective device analysis will be performed for ESS interconnections in a similar manner to that of a proposed site that does not include ESS. As ESS is a dispatchable source, time of day operations of the site and any other site specific control schemes incorporated into the design will be factored into the analysis, as well as the implementation of any advanced functions.

Further discussion regarding specific ESS specific design aspects are provided in the subsequent sub-sections. The Joint Utilities acknowledge the evolving nature of ESS technology, design aspects, and state incentives that may drive new and unique site designs in the future. In the interest of collaboratively progressing toward the most efficient state of the electric power system, the Utilities will consider any and all proposed designs, seeking to ensure system safety, reliability, and efficiency.

## 16.2 Coupling

Systems may be interconnected as stand-alone storage systems, or coupled with distributed generation, such as photovoltaics. Where coupled with DG, coupling may be accomplished either by DC coupling behind a single inverter, or via AC coupling through multiple inverters.

## 16.3 Limiting Export

Customer proposals to limit export of a paired ESS + solar facilities are evaluated by the Utility on a case-by-case basis based on the certified operational characteristics and technical review sizing principles acceptable to the individual Utility, though not indicative of a standard going forward for all projects.

The purpose of a Customer's proposed power export limiting scheme is to limit the maximum export capabilities from the Facility. Export will be considered as the generation capability at the terminals of the generator.

Limiting site export generation would generally impact the load flow analyses of the interconnection, in some cases reducing required system modifications from what would otherwise have been required for full nameplate output.

A utility-grade, ANSI C37.90, protective relay device is required for limit control functions. The relay sensing must be located at the point of common coupling. Specific location is subject to review by the Utility for appropriate placement. The total system accuracy must be factored into the proposed relay settings, which must be calculated based on the highest power export case that has the largest sum accuracy of the protective devices in the control scheme. A root mean square (RMS) calculation method is insufficient to calculate the worst-case error and meet the Utility equipment system protection needs. Class I resources (less than or equal to 60kW) on radial feeders shall not be subject to ANSI C37.90 relay requirements. For projects with an acceptable site limiting scheme, the limited site export generation would be used in calculation/analysis of load flow analyses including but not limited to the following:

- Conductor thermal capabilities (short-term and long-term contingencies)
- Exceeding equipment nameplate ratings (e.g. transformer, regulators, etc.)
- Flicker
- Steady state voltage analysis
- Power factor analysis

For analysis related to fault conditions and risk of islanding concerns it is necessary to consider the full nameplate capacity of the inverters, therefore the limited site export generation would ***NOT*** be used in the calculation/analysis of these conditions.

## 16.4 Charging Methods

Customers may elect to charge ESS from locally paired DG or may request to charge from the Utility source or both. The distinction must be made prior to commencement of engineering studies, as this design approach will have a significant impact in the methodology used to evaluate the proposed site.

If electing to charge from local DG only, the design must explicitly describe and illustrate the means by which the site will protect against Utility charging, subject to review and approval by the Utility.

If requesting to charge from the Utility source, the Utility may, in its sole discretion, elect to evaluate the charging aspect of the design as a new load customer request. If progressed in this manner, the site would be subject to the Utilities typical procedure for new load customer interconnection, and not subject to MDPU 1320, specifically for the charging mode where the site appears as a load customer. Consideration of sites in this manner will be project specific and evaluated on a case by case basis.

## 16.5 Required Information

The following section itemizes a list of typical information that is required in order for the Utility to complete their analyses.

Note that portions of this information are required to be collected by the Utilities in order to comply with DOER reporting, which is intended to track progress toward Massachusetts state goals (See Chapter 227, Section 20). This information will be used by the Utility as peripheral information to inform intended site operating parameters, however all requested information is not expected to have a direct impact on the progression of the engineering analyses.

As of the time of writing, the exact list of requested information has been submitted to the DPU for feedback. Pending the response, the specific list of information will be included herein, which will identify required information in further detail.

## 16.6 Energy Storage Study Process

Due to the complications associated with energy storage interconnections, the following process was created as a means to provide project information early in the study process that allows for customers to make an informed decision on their project, while minimizing overall process delays to other projects in queue. The below describes the general approach adopted by all EDC's. Each EDC will provide company specific detail on their respective websites.

### 16.6.1 General Process Description

1. Deliver Initial Review/Screening Memo (Existing Tariff timelines)
    a. Requires System Impact Study (SIS) with mutually agreed upon time frame
    b. SIS timeframe to begin once customer payment is received

2. Primary Assessment (40BD)
    a. Once begun other applications following this project in the queue will not be progressed beyond Initial Review/Screening until step 4 of this process is complete.
    b. The Primary Assessment will be performed to the extent possible without employing modeling software. Assessment will include:
        i. Thermal analysis - worst case calculations on normal feeder and N-1 contingency case
        ii. 3V0 assessment
        iii. Risk of Islanding assessment
    c. Customer documentation review for compliance with Company standards Primary assessment to be performed for two different scenarios
        i. Unscheduled – allowing charge or discharge at full capacity at any time of day/year
        ii. Scheduled – Restricting charge/discharge operation to the EDC standardized schedule
            1. Standardized schedules for each EDC will aim at avoiding capacity related substation and/or feeder upgrades and are subject to change based on detailed review
            2. Unique schedules different than standardized schedule will not be permitted.
    d. Engineering analyses progressed in subsequent study stages may identify additional system modifications beyond those capable of being identified in the Primary Assessment and will be communicated as part of the final study report.

    *Note: The above describes the baseline expectation that customers will be evaluated for both Scheduled AND Unscheduled operation. At the time of original application, customer will be given the ability to identify if they would like to be considered as only Scheduled OR only Unscheduled, foregoing the analysis of the unselected option. Due to the reduced, Primary Assessment timelines would be as follows:*

    - *Scheduled Only – 30BD*
    - *Unscheduled Only – 20BD*

3. Deliver Primary Assessment

a. EDC identifies results of the analyses including specific system limits that are being exceeded, prompting the need for system modifications.
b. Means customer will be provided information on up to 4 different possible paths forward:
    1. Unscheduled – System mods as required to accommodate proposed system rating
    2. Unscheduled – System limits to inform derating opportunities
    3. Scheduled – System mods as required to accommodate proposed system rating
    4. Scheduled – System limits to inform curtailment opportunities

    *Note: Should customer have elected on the original application to omit Primary Assessment of Schedule OR Unscheduled, those results would be omitted from the delivered results.*

c. High level system mod scope to be provided. Specific cost estimates will not be provided, however costs for typical scopes of work are publicly available online for each EDC.

*Note: Engineering analysis will include N-1 contingency analyses in alignment with each EDC's technical standards and Distribution Automation Scheme. This analysis will generally consider specific N-1 scenario(s), however it is not possible to cover the full spectrum of possible real-world contingencies that might materialize. The results of contingency analyses will identify system modifications required to accommodate site interconnection in the specific N-1 conditions considered, which will minimize the need for utilities to direct a DG or ESS site to disconnect. However, this analysis does not preclude the utility in its sole discretion, in alignment with the tariff, from the ability to direct a site to come offline if system conditions exist under an abnormal system configuration.*

4. Customer Decision (10BD)
    a. Customer to decide on one of the four paths forward that will be the basis for the SIS.
        i. Application on hold pending customer decision on path forward
        ii. Customer confirmation of intended de-rating and/or curtailment is acceptable to move the application forward, lifting the hold. However updated documents must be submitted in a timely manner by the customer thereafter to reflect the update (within 15BD following customer confirmation).
            1. Note that failure to provide updated drawings in a timely manner and/or any drawing updates beyond the specific de-rating and/or curtailment modifications may result in subsequent study hold periods, at the discretion of the EDC.

b. Once decided, this establishes the base case for the next application in queue, allowing that applicant to proceed.

*Note: Results of the Primary Assessment are reflective only of those known system modifications required from the analyses identified in item #2. Regardless of the decision in this step by the customer, the balance of the System Impact Study may illustrate the need for additional System Modifications that could not be identified in the Primary Assessment set of analyses.*

5. Complete SIS (55BD)
   a. EDC completes SIS based on confirmed or updated operating methodology provided by customer in step 4.
      i. Any change to the decision will be considered Significant, subject to application withdrawal
   b. Other project design changes will be evaluated according to EDC policy on Significant and Moderate changes per tariff, as would occur on any other SIS

### 16.6.2 Company Specific Process Descriptions

The following are links to each EDC's company specific detail on ESS study process.

National Grid:
https://ngus.force.com/servlet/servlet.FileDownload?file=0156T00000GBVuN

Eversource:

Unitil:

# 17.0 Significant vs Moderate Changes

As part of the interconnection process, customers may request to make changes to their designs at any time. In accordance with the Tariff these changes are to be assessed by the EDC to determine whether the change is Significant or Moderate. The following defines these terms and the associated impacts to the DG application.

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

1. Customer Impact: Results of studying the change may have an adverse impact to other customers that are in queue at the time the change is requested. Projects that are post-ISA must adhere to what is in the agreement, so this applies to changes proposed to pre-iSA applications.

Examples of effects to others in queue include, but are not limited to, reducing electrical capacity availability, causing the need for new cost obligations, causing delay to either study or construction timelines, etc.

i. Modifying the base case assumptions used for evaluation of other applications
ii. Adjusting required system modifications

***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:

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

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

1. Customer Impact: The change has no possibility of impact to other 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 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:

i. Inverter manufacturer change
ii. Adjustment to transformer impedance
iii. Recloser setting adjustment

Note: For changes associated with a project in a Group Study, the change approval process in Section 3.4.1 of MDPU 1468 shall be followed.

## Revision History (version history prior tracking started December 2022)

| Version | Date | Description of Revision |
|---|---|---|
| 1.0 | 12/22/22 | Added ESS study section under sect 16; updated misc links; deleted “authors” from cover sheet as this is a living document |