Massachusetts Technical Standards Review Group

Common Technical Standards Manual

To accompany M.D.P.U. No. 11-75-E

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1.0 Introduction

This document has been developed to highlight commonalities and differences among Massachusetts public electric utilities with regard to technical standards, practices, and requirements for the interconnection of distributed generation. This document was developed by the Massachusetts Technical Standards Review Group, a joint venture between National Grid, NSTAR, Unitil, and Western Massachusetts Electric Company, with input from appointed representatives from stakeholder DG industries and Government departments. It was developed at the request of the Massachusetts Distributed Generation Working Group, under order of the Massachusetts Department of Public Utilities. This document serves to augment the Standards for Interconnecting Distributed Generation (the Tariff), and provide additional technical clarification of Company-specific policies throughout the state of Massachusetts. The Common Technical Standards Manual serves as a base-level guideline for the interconnecting customer, and any Utility-specific technical standard may take precedence over the guidelines outlined within. Future revisions of this document will be made available on the DOER TSRG Homepage.

2.0 Existing Utility-Specific Standards and Guidelines

The following documentation should be reference 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.

2.1 National Grid – ESB 756, Appendix C

http://www.nationalgridus.com/non_html/shared_constr_esb756.pdf

2.2 NSTAR – 14-Point Clarification Document

http://www.nstaronline.com/business/rates_tariffs/interconnections/documents.asp

2.3 Unitil – Distributed Energy Resources Homepage

http://www.unitil.net/der/

2.4 WMECO – Distributed Generation Requirements

http://www.wmeco.com/residential/understandbill/ratesrules/distribgenrequirements.aspx

3.0 Anti-Islanding

In the event that a portion of the utility electric system is electrically separated from the rest of the electric system, a DG facility on that section of the system could possibly island with the load on that section, such that insufficient anti-islanding provisions at the DG facility could lead to run-on times beyond the 2 second limit prescribed in IEEE 1547. The following section describes each utilities' anti-islanding screening methodology, as well as mitigation requirements for projects that fail anti-islanding screening.

3.1 National Grid

3.1.1 Screening

DG applications over 500kW are screened for potential islanding conditions. National Grid conducts detailed Risk of Islanding studies for all projects that fail anti-islanding screening. The screening tools vary by type of DG technology, and are as follows:

- PV: Sandia 2012-1365 screening tool
- Rotating Generation: If aggregate rotating generator size <33% minimum feeder load then anti-islanding study is not required. If aggregate rotating generator size >33% minimum load and there are enough VAR sources on the islanded section of the feeder to self excite the generator, islanding study is required.
- PV in parallel with rotating generators: If aggregate rotating generator size > 20% aggregate PV rating and there are enough VAR sources on the islanded section of the feeder to self excite the generator, islanding study is required.

If a detailed Risk of islanding determines that run-on times can exceed 2 seconds, a direct transfer trip scheme is required.

3.2 NSTAR

3.2.1 Screening

Preliminary screening tools such as Load to Generation ratio, fault current contribution, amount and type of other DG on the feeder and reactive power matching are used to determine whether there is a risk of islanding a give facility. Once a risk is identified NSTAR may implement a more advanced protection or transfer trip scheme, ask for system upgrades or suggest the customer decrease the power their facility is exporting.

3.3 Unitil

3.3.1 Screening

DG applications are screened for potential anti-islanding by load to generation ratio at each device location that could operate to form an island boundary. Unitil conducts detailed Risk of Islanding studies for all projects that fail anti-islanding screening. The screening tools vary by type of DG technology, and are as follows:

- PV: DG < 50% minimum daytime load
- Rotating Generation: DG < 33% minimum load
- Aggregate and/or mixed resources: DG < 50% minimum load

If a detailed Risk of islanding determines that run-on times can exceed 2 seconds, a direct transfer trip scheme is required.

3.4 WMECO

3.4.1 Screening

DG applications are screened for potential anti-islanding by load to generation ratio, per feeder section. WMECO requires DTT for all applications that fail anti-islanding screening. The anti-islanding screen is as follows:

- DG < 33% minimum load

3.5 Anti-Islanding Mitigation (Common)

Direct Transfer Trip is the common means of anti-islanding mitigation. Leased phone-line is the most common communications medium, although radio systems can be used where line-of-sight is available.

4.0 Other DTT Utilizations

4.1 National Grid

N/A - Direct transfer trip schemes are used solely as an anti-islanding mitigation practice.

4.2 NSTAR

Direct transfer trip schemes are used primarily for mitigating reverse power flow at the upstream substation supply transformer, but can also be utilized to mitigate voltage conditions and flicker that may develop due to the interconnection of DG. Direct transfer trip is considered for any facility that may cause any of the adverse conditions mentioned above, and also where upstream devices are at risk of reclosing out of step during an adverse condition. If a System Impact study determines that system stability or power quality standards are compromised under certain load to generation conditions, a direct transfer trip scheme may be required to disconnect the DG.

4.3 Unitil

Direct transfer trip schemes may be required for fault mitigation at the transmission level.

4.4 WMECO

Direct transfer trip schemes may also be required in the event of loop-scheme feeder transfers through networked reclosers.

5.0 DG Capacity – Feeder Limits

5.1 National Grid

80% of the feeder cable thermal rating (aggregate 9 MVA generation on a 15kV class feeder) is the limit for the regular feeders. Larger generation can be interconnected to the express feeders if proper cable size is used.

5.1.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of maximum Peak

5.2 NSTAR

The DG's effect on LTC operations is considered as part of the System Impact Study. No hard limit.

5.2.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of Peak

5.3 Unitil

Capacity issues are considered as part of the System Impact Study. No hard limit.

5.3.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of Peak

5.4 WMECO

Capacity issues are considered as part of the System Impact Study. No hard limit. Application with a considerable load to generation mismatch are flagged in the application process.

5.4.1 Minimum Daytime Load Approximation if the measurement data is not available

Minimum load = 25% of Peak

6.0 Remote Control & Monitoring

6.1 National Grid

National Grid requires the installation of an RTU for non-Independent Power Producer DG applications at the following thresholds:
5kV: DG ≥ 500kW
15kV: DG ≥ 1MW
+15kV: DG ≥ 1.8MW
Remote control is installed on the generator breaker, parallel to the load. Otherwise, the PCC recloser will be controlled through telemetrics. Any device capable of DNP3 can be used in lieu of the RTU.
For Independent Power Producer (IPP) applications, pole-top reclosed are utilized for analog and status points at the Point of Interconnection.

6.1.1 Data Monitored

- kW, kVA, KVAr
- A,B,C phase amps
- A-B, B-C, C-A voltages
- Customer breaker status (supervisory only)

6.1.2 Communications Medium

- Leased multi-protocol line (MPLS).

6.2 NSTAR

NSTAR installs SCADA-capable PCC reclosers.

6.2.1 Data Monitored

- Net Power

6.2.2 Communications Medium

- MDS Radio

6.3 Unitil

Unitil requires the installation of real-time remote monitoring via a RTU or similar equipment for DG facilities of 1MVA and above. This monitoring is required at the designated interconnection Interrupting Device for the overall DG facility. If a company-owned recloser at the PCC is being required for other reasons, monitoring of that recloser can serve this purpose.

In addition, Unitil also requires real-time remote monitoring at any Interrupting Device for each individual unit of more than 500kVA, even if the Interrupting Device for the overall DG facility is also being monitored. For units from 250kVA to 500kVA, recording interval metering may be allowed instead of real-time monitoring, and revenue metering that may otherwise already be required can serve this purpose.

Unitil requires remote control only for larger installations using system-specific determinations.

6.3.1 Data Monitored

- Connection or Unit Status
- Active and Reactive Power Flow (three-phase)
- Voltage – facility or unit side (per phase)

- Voltage – utility side
- Current (per phase)
- Frequency – facility or unit side
- Protective Relay Status (if applicable)
- DC Control System Status (if applicable)
- other states or quantities as specifically warranted

6.3.2 Communications Medium

- to be determined case-by-case

6.4 WMECO

WMECO installs SCADA-capable PCC reclosers. Reclosers can be used to remotely disconnect the generator.

6.4.1 Data Monitored

- N/A

6.4.2 Communications Medium

- N/A

7.0 PCC Recloser Requirements – Threshold DG Size

7.1 National Grid

5kV: DG $\geq$ 500kW

15kV: DG $\geq$ 1000kW

7.2 NSTAR

DG $\geq$ 1MW

7.3 Unitil

DG $\geq$ 1MW

7.4 WMECO

DG ≥ 1MW

NOTE: Utilities reserve the right to implement a recloser in any case it is deemed necessary to interconnect a DG facility with the potential to cause an adverse condition.

8.0 External Disconnect Requirement – Small DG Threshold Size

8.1 National Grid

DG >25kW

8.2 NSTAR

DG >10-25kW

8.3 Unitil

DG > 10kW

8.4 WMECO

DG > 10kW

9.0 Witness Test Protocols

9.1 National Grid

National Grid requires witness testing of the Customer redundant relaying for DG ≥ 500kW. For DG < 500kW, National Grid requires testing of generator internal relaying, as well as UL certification. The

Witness Test is conducted by a third party, and attended by a Utility representation for supervision and approval of results. ESB 756C provide a sample witness test.

9.1.1 Required Documentation

- Witness test procedure
- Energization plan

9.1.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Underfrequency ride-through should be modified according to the NPCC A.03 curve. Clearing times include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51C Phase Overcurrent (Voltage-Controlled)
- 59N Neutral Overvoltage

9.2 NSTAR

NSTAR requires witness testing of the Customer redundant relaying for PV$\geq$1MW, Synchronous DG $\geq$ 500kW, and all asynchronous DG. For DG < 200kW, NSTAR requires that the Customer submit pictures of the installation, documentation of UL listing of the equipment, and proof of compliance with all applicable codes.

9.2.1 Required Documentation

- All information called for within the NSTAR Tariff and 14-Point clarification document
- Relay settings
- Coordination study

9.2.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Underfrequency ridethrough should be modified according to the NPCC A.03 curve. Clearing times include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51 Phase Overcurrent
- 59N Neutral Overvoltage

9.3 Unitil

For Simplified Track projects, Unitil conducts witness testing during the meter upgrade.

9.3.1 Required Documentation

- Witness test procedure

9.3.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Fast response clearing times (e.g. 0.16 sec.) include breaker operation.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51 Phase Overcurrent
- 59N Neutral Overvoltage

9.4 WMECO

For DG $\geq$ 30kW, WMECO conducts witness tests of the customer redundant relays. For DG < 30kW, the witness test confirms that the system is installed per the application, and that the generator protection complies with 2-second trip and 5-minute reconnection time.

9.4.1 Required Documentation

- Certified test results
- Print-out of inverter settings
- One-Line Diagram
- Three-Line Diagram
- Relay schematic

9.4.2 Required Test Points

Relay set-points should be specified in accordance with IEEE 1547. Underfrequencyridethrough should be modified according to the NPCC A.03 curve.

- 27 Undervoltage
- 59 Overvoltage
- 81o/u Overfrequency, Underfrequency
- 51N Neutral Overcurrent
- 51 Phase Overcurrent
- 59N Neutral Overvoltage

9.5 Failure Protocol (Common)

In the event of a failed witness test (i.e. test results of a relay function fall outside of a certain tolerance), the witness test is rescheduled, and the failed elements are retested.

10.0 Inverter Power Factor Requirements

10.1 National Grid

+/- .95

DG may provide static pf regulation at the PCC. If the circuit has no voltage regulators, the DG may provide active pf regulation at the PCC.

10.2 NSTAR

Unity *(Required at generator terminals)*

10.3 Unitil

+/- .95

10.4 WMECO

+/- .95

11.0 Interface Transformer Winding Configurations

The following section describes transformer winding standards for effectively-grounded systems. In all service territories, neutral grounding reactors may be required in the event that existing grounding fault detection is compromised by the addition of DG. Each utility maintains a handful of ungrounded circuits, for which alternate winding configurations may be acceptable. For 4-wire, multi-grounded circuits, the preferred transformer configurations are:

11.1 National Grid

11.1.1 Approve Winding Configurations

Wye-grounded x delta (fully isolated neutral)

Wye-grounded x wye-grounded (with effectively grounded source)

Wye-grounded x wye-grounded (with secondary grounding bank)

Delta x wye-grounded (with primary grounding bank)

11.2 NSTAR

11.2.1 Approve Winding Configurations

Delta x wye (with 59N relay on primary)

Wye-grounded x delta

11.3 Unitil

11.3.1 Approve Winding Configurations

Wye-grounded x delta

11.4 WMECO

11.4.1 Approve Winding Configurations

Evaluated application by application

12.0 Customer Redundant Relaying

At certain facility sizes, utilities may require redundant utility-grade relaying to disconnect the generator under faulted conditions. 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). Relays must be located upstream of the grounding source, on the customer side of the PCC. For a list of required relays, refer to the Witness Test

Protocols in Section 9. Customers may install motor-operated switches for remote reconnection, but are prohibited from utilizing auto-reclosing.

12.1 National Grid

Required at DG $\geq$ 500kW

12.2 NSTAR

Required at DG $\geq$ 1000kW

12.3 Unitil

No specified threshold for requiring redundancy

12.4 WMECO

Required at DG $\geq$ 1000kW

13.0 Reverse Power Flow (Substation Level)

13.1 National Grid

National Grid permits reverse power flow through the supply transformers. In the event of reverse power flow, zero-sequence overvoltage relaying (59N) is required on the high-side of the supply transformer (if Delta). For transmission systems < 115kV, VT's are required. For transmission systems > 115kV, capacitively-couple VT's are required.

Screening for the 59N requirement is accomplished through an N-1 scheme, for which the most heavily loaded feeder on the bus is removed from the calculation. The remaining screening is:

DG $\geq$ (.66)*(min load @ N-1),

where 59N is required when the aggregate DG on the low side bus is greater than 2/3 of the load.

13.2 NSTAR

NSTAR permits reverse power flow based on the particular manufacturer, vintage, and size of the supply transformer in question.

Reverse powerful is prohibited on older vintage transformers, unless written consent is provided by the transformer manufacturer.

13.3 Unitil

Unitil permits reverse power flow through supply transformers that are outfitted with primary VT's. In instances where primary CT's are not viable, DTT may be used to disconnect the facility for transmission faults.

13.4 WMECO

WMECO considers reverse power on a case-by-case basis.