ORANGE & ROCKLAND UTILITIES

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TECHNOLOGY ENGINEERING DEPARTMENT

DISTRIBUTED ENERGY RESOURCE INTERCONNECTION HANDBOOK (DERIH)

EFFECTIVE DATE

November 2022

REQUIREMENTS FOR PARALLEL GENERATION UP TO 5MW CONNECTED TO ORANGE AND ROCKLAND'S ELECTRIC DISTRIBUTION SYSTEM

TARGET AUDIENCE	DISTRIBUTION ENGINEERING ELECTRIC OPERATIONS REVENUE METERING ENERGY SERVICES DER CUSTOMERS NEW BUSINESS TECHNOLOGY ENGINEERING

Revision Table

REVISION TABLE			
Revision Level	Author	Date	Description
1st Draft	D. Savino	9/15/2020	Initial document based on EPRI's Technical Interconnection and Interoperability Requirements
2nd Draft	D. Savino	10/18/2020	Improved Formatting of sections & numbering thereof
3rd Draft	O. Shmul	2/5/2021	Added Appendix B1-B9 and Appendix E.
4th Draft	S. Melakathu	9/24/2021	Separated Appendices from base DERIH. Added Appendix I and Appendix J.
5th Draft	A.J. Anaya	5/16/2022	Reviewed edits from T. Brown and L. Leon.

Preface

This Distributed Energy Resource Interconnection Handbook (DERIH) is meant to be a valuable tool in helping contractors and developers successfully connect to the electric power system in the territory of Orange & Rockland Utilities. Orange & Rockland supports the energy goals of the New York State Reforming the Energy Vision strategy. Orange & Rockland's Technology Engineering department is committed to providing a positive customer experience for all applicants interested in connecting Distributed Energy Resources to its electric power system. All suggestions and inquiries are welcomed at 845-577-3683 or email ORU_DG@oru.com. For the best experience, please be sure you are referencing the most up to date document located on our website.

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1.Introduction

1.1. Scope and Applicability

This Technical Interconnection and Interoperability Requirements (TIIR) document specifies technical requirements for grid interconnection and parallel operation with the grid. It provides criteria for Customers planning to interconnect Distributed Energy Resources (DER) up to 5000 Kilowatts AC with the Orange & Rockland Utilities' distribution system. The utility distribution includes AC medium voltage (greater than 600 V to 34.5kV) and AC low voltage (less than or equal to 600 V) connections and are covered in this document. The requirements apply to all aspects of DER interconnection and operation with the utility grid. For DER greater than 5000 Kilowatts AC please refer to the Orange & Rockland Utilities Document "**Operating, Metering, and Equipment Protection Requirements for Parallel Operation of Large-Size Generating Facilities Greater than 5,000 Kilowatts Connected to the Distribution System**".

The document addresses responsibilities of the Customer related to the grid integration, point of connection, and general system performance. It includes operational performance, power quality, protection, monitoring, control, and telemetry requirements. Interoperability with other grid equipment, as well as, metering, commissioning test and verification requirements are also addressed. The document also covers specific operating requirements and any special protection that may be required for connections on radial or network locations in the distribution grid.

Orange & Rockland Utilities has adopted IEEE Std 1547™-2018, as amended by IEEE Std 1547a-2020, for all DER interconnected to the distribution system. All DER interconnecting under these TIIRs shall meet requirements as specified in IEEE Std 1547™-2018 and be tested, verified, or certified according to applicable standards IEEE Std 1547-2018 clauses that are pertinent to sections in this document are identified throughout this document. Note that although some clauses are identified in this document, the entirety of IEEE Std 1547-2018™ has been adopted and is pertinent to the DER interconnection. Requirements that are beyond the scope of IEEE Std 1547-2018™ are also included in this document.

The requirements specified in this document shall apply to all DER interconnection request applications.

1.2 Responsibilities

1.2.1 Customer-Owned Generating Equipment

The Customer is responsible for designing, installing, operating, and maintaining its own equipment in accordance with interconnection agreements and applicable standards. The interconnection shall comply with IEEE Std 1547-2018™, the National Electrical Code, and all applicable laws, statutes, guidelines, and regulations. Interconnections in New York must comply with the NY Standardized Interconnection Requirements (SIR). Interconnections in New Jersey must comply with the New Jersey Administrative Code. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the Customer's and Orange & Rockland Utilities' facilities.

Starting in January 2023, inverters shall be UL 1741 SB, or equivalent standards, certified as “Grid Support Interactive Inverter” or “Grid Support Utility Interactive Inverter” installed or commissioned with the IEEE Std 1547™-2018 specified performance capabilities.

1.2.2 Utility Managed and Operated Distribution System

Requirements specified in the DERIH are also intended to complement utility efforts and responsibility to maintain distribution grid safety, power quality and reliability. Continuity and quality of service to all customers is a key responsibility of the utility.

1.2.3 Requirements Related to Ongoing Utility Upgrades

The utility system is constantly changing due to shifts in loading and the addition or removal of generation. The possibility exists that a change in the utility system may cause a change in the protection or other requirements at the generation interconnection. Any change in requirements will be communicated to the Customer. The Customer’s responsibility for changes is specified in the interconnection agreement.

2. Definitions and Acronyms

2.1. Definitions

Terminology used in this document is intended to follow definitions and usage in IEEE Standard 1547™-2018, other related IEEE, IEC, and ANSI standards. In some cases, terms related to the FERC-SGIP and NFPA related codes such as the US National Electric Code, NFPA-70 are used.

A few definitions are provided here for convenience or if unique to this document.

Account – An account is one metered or un-metered rate or service classification which normally has one electric delivery point of service. Each account shall have only one electric service supplier providing full electric supply requirements for that account. A premise may have more than one account.

Distribution Control Center (DCC) – The Orange & Rockland Utilities’ Distribution Control Center that monitors and has direct control over the operation of the utility’s Power Delivery System.

Company – Orange and Rockland Utilities, Inc., and Subsidiaries. Also referred to as O&R and ORU.

Customer – Any adult person, partnership, association, corporation, or other entity whose name a service account is listed. A Customer includes anyone taking delivery service or combined electric supply & delivery service from the Company under one service classification for one account. Customer is also responsible for any DER at connected to the electric system at the account.

Distributed Energy Resource (DER) – any generation source designed to operate in parallel with the Grid that includes both generators and energy storage technologies capable of exporting active power to an Electric Power System (EPS).

Electric Power System (EPS) – the utility power distribution system.

Facility (or Facilities) – The Customer owned DER equipment and all associated or ancillary equipment, including interconnection equipment, on the Customer’s side of the Point of Common Coupling

Grid – The interconnected arrangement of lines, transformers and generators that make up the electric power system (EPS). In this document Grid refers to the medium and low voltage portions of the grid.

Integration margin –Limits, defined and used to protect the grid by providing a safety margin added to DER integration limits, for example, limiting interconnection by kW due to thermal constraints of conductors.

Interconnection Agreement(s) – Any contract between Orange & Rockland Utilities and one or more parties that outlines and governs the interconnection requirements of a DER facility.

Interconnection Equipment - equipment necessary to safely interconnect the Facility to the EPS, including all relaying, interrupting devices, metering, or communication equipment needed to protect the facility and the utility power delivery system and to control and safely operate the facility in parallel with the utility power delivery system.

NERC - North American Electric Reliability Corporation. The purpose of NERC is to ensure the adequacy, reliability, and security of the bulk electric supply systems through coordinated operations and planning of generation and transmission facilities.

Parallel Operation – Any electrical connection between the utility grid and the customer's DER that is operating in synchronization with the EPS.

Permission to Operate (PTO) – Utility approval for parallel operation of DER.

Point of Common Coupling (PCC) – The point of connection between the Area EPS and the Local EPS. (Excerpted from IEEE Std 1547™-2018)

Point of DER Connection (PoC) - The point where a DER unit is electrically connected in a Local EPS and meets the requirements of IEEE Std 1547™-2018 exclusive of any load present in the respective part of the Local EPS. (Excerpted from IEEE Std 1547™-2018)

Point of Interconnection (POI) – Used prior to Permission to Operate (PTO). Point where proposed new construction begins and is studied to interconnect with the existing Area EPS. The customer is responsible for obtaining all planning board approvals for the new construction from the POI.

Point of Ownership (POO) - Demarcation point between customer owned equipment and utility owned equipment. The Utility will construct the new infrastructure up to the POO unless additional scope of work is agreed upon by the customer and the Utility New Business Department.

Revenue Metering - For purposes of this document, revenue metering shall refer to the meter or meters used for billing purposes and the instrument transformers, communications equipment, and wiring between these devices.

RTU (Remote Terminal Unit) – The remote unit of a supervisory control system used to telemeter operating data, provide device status/alarms and to provide remote control of equipment at a substation or generator site. The unit communicates with a master unit at the Distribution Control Center.

Reference Point of Applicability (RPA) – The reference point of applicability for any requirement varies and can be at the Point of Connection (PoC) or Point of Common Coupling (PCC), or either. DER Requirements of this document apply to the RPA. (Excerpted from IEEE Std 1547™-2018; the location concept is defined in Clause 4.2.)

System Emergency – An imminent or occurring condition on the utility power delivery system, the ISO/RTO System, the system of a neighboring utility, or in the facility that is likely to impair system reliability, quality of service, or result in significant disruption of service, or damage, to any of the foregoing, or is likely to endanger life, property, or the environment.

Telemetry – The process of recording and transmitting the readings of an instrument. For example, collection of measurements or other data at remote or inaccessible points and their automatic transmission to receiving equipment for monitoring. In the case of DER, applications include telemetry for protection device status, power flows, settings, and other facility or related utility equipment condition status.

2.2. Acronyms

ACR – Automatic Circuit Recloser

DA – Distribution Automation

DER – Distributed Energy Resource

DGR – Distributed Generation Recloser

EMI – Electromagnetic Interference

EPS – Electric Power System

ESS – Energy Storage System

NGR – Neutral Grounding Reactor

PoC – Point of Connection

PCC – Point of Common Coupling

POI – Point of Interconnection

POO – Point of Ownership

RPA – Reference Point of Applicability

TIIR – Technical Interconnection and Interoperability Requirements

3. General Principles of Interconnection

The general principles of these interconnection requirements are:

a) DER interconnection and operation shall not compromise the safety of the public or utility personnel.
b) DER interconnection shall not degrade service to any customers by causing interruptions or power quality events.
c) DER interconnection shall not compromise the security or reliability of utility electrical systems and shall be responsive to the utility's directions during defined emergency conditions or to requests to remove the DER from service when the utility is performing work on the circuit to which the DER is connected.
d) It is the customer's responsibility to design, install, operate, and maintain all customer sided equipment necessary for connection to the O&R system.
e) O&R shall be consulted in the early planning stage of the generation proposal before any equipment is purchased, whether for paralleling or standby generation. Any electric power producing equipment such as solar-electric panels, fuel cells, windmills, micro-turbines, etc., even if it has an inverter-based utility interface, is considered generating equipment.
f) Any expense incurred by O&R to provide interconnection to the customer shall be the responsibility of the customer.
g) All installations of a customer's generating equipment shall require adherence to fundamental rules for the safeguarding of all personnel and O&R 's equipment. The installation must be in accordance with the latest editions of O&R's specifications, National Electrical Code, NFPA 70; National Electrical Safety Code, C2; and be inspected and approved by O&R.
h) All installations proposed on delta 2.4kV or 4.8kV may require additional study to determine if the system can be safely connected or if additional upgrades will be required.
i) Rooftop generating equipment is preferred to be supplied from the metered account associated to the building. If the rooftop system has a separate service, there must be a single point of emergency disconnect for both the building and DG services. See Appendix B-9.
j) Installations with a rating over 500kW will require power quality (PQ) Monitoring and a Recloser (DGR) at the PCC. These will be installed by O&R at the customer's expense. This includes behind the meter systems.
k) DGR location above may make critical load vulnerable to de-energization if the DGR trips. Design of the system should take this into account. For example, have a separate service for HVAC and other auxiliary loads.
l) Installations with a rating over 500kW will require capacitor banks on the circuit to be upgraded with SCADA capability to give monitoring and control capabilities in the event of PQ or voltage issues.
m) If the number of poles is a concern, consider having Primary Metering in a pad mounted cabinet.
n) The interconnection poles (PQ Monitoring, DGR, Primary Metering) will begin at the property line. O&R will not construct and maintain a pole line on private property to get to the interconnection poles.

o) Sustainability – Ground mounted solar DG installations that require significant acreage must follow the **Solar Site Restoration and Management Specification** in the Appendix.

p) If a property is landlocked with no public road frontage, O&R will not construct and maintain a pole line on the private properties needed to be crossed to arrive at the DER property. The customer will need to cross these properties with a customer owned, installed, and maintained underground service.

q) The customer shall be connected to the circuit serving the area. Minor circuit re-configuration will be considered. However, constructing additional primary and double circuit primary in order to connect a project to an alternate circuit may be considered under cost sharing rules.

r) Service Connection:

1. All customer generation installations greater than 100kW are required to be three phase to help mitigate phase imbalance and power quality issues.

2. All services shall comply with **Orange and Rockland General Specifications for Electric Installations** as well as all applicable local, state, and federal codes and standards.

3. All costs associated with service upgrades required to accommodate customer generation are the responsibility of the customer.

4. O&R will supply only one service to a building except where, in the sole judgement of O&R, special conditions require the installation of more than one service run. O&R reserves the right to designate the location of the service point. Failure to obtain approval by O&R may result in a customer charge or customer relocating their service.

5. To de-energize the electric service for safe working conditions, arrangements can be made by contacting New Business Services during normal working hours.

6. The point of interconnection of any generating equipment shall be installed on the customer side of the main service meter. Connection inside of service metering equipment, such as meter pans or current transformer cabinets, is strictly prohibited.

7. The customer's service equipment shall be rated at a minimum to support the maximum fault current available from O&R's distribution system plus the contribution from the customer generation and motor loads.

8. Single phase generation shall not be connected to sites served by a three-phase service.

4. General Technical Requirements

The DER interconnection shall comply with IEEE 1547™-2018 and IEEE 1547.1™-2020. Inverters shall be UL 1741 certified as "Grid Support Interactive Inverter" or "Grid Support Utility Interactive Inverter" installed or commissioned with the IEEE Std 1547™-2018 specified performance capabilities.

In addition, the Customer is responsible for compliance with other codes such as: The National Electrical Code, Local Safety Codes, North America Electric Reliability Council rules (applicable for independent system operators), and all applicable laws, statutes, guidelines, and regulations. This includes installing, setting, and maintaining all protective devices necessary for safe grid integration and to protect the Customer's facilities.

4.1. Applicable Voltages

Requirements for applicable voltages are specified in IEEE Std 1547™-2018 clause 4.3 - Applicable Voltages. Medium voltage is defined as voltage over 1000V. Low voltage is defined as voltage under 1000V.

4.2. Service Transformer Connections

Low voltage DER connections are normally interconnected via an existing load service transformer. Larger facilities may require either an upgrade of the service transformer or the addition of a DER facility service transformer.

4.2.1. Distribution Service Transformer Capacity

The size of the service transformer is a limiting factor for determining the maximum DER size. The following shall be considered when determining if a DER interconnection application may require a service transformer upgrade:

1. Aggregate DER nameplate rating is greater than the transformer nameplate rating.
2. When voltage-rise associated with DER power back feed is anticipated, the service transformer may need to be upgraded to maintain voltage with standard limits.

4.2.2. Transformer Configuration Requirement

The following transformer winding configuration requirements shall apply.

	Utility Side	**DER Side**
Acceptable	Grounded Wye	Grounded Wye (Grounding Transformer TBD)
	Grounded Wye	Wye (Grounding Transformer TBD)
	Grounded Wye (with NGR)	Delta

4.2.3. Basic Insulation Levels (BIL)

The BIL rating of any new transformer, circuit breaker, recloser, and any other electrical equipment connected to the utility power system must coordinate with the requirements of the utility system at the PCC. All customer equipment should have the BIL rating of the utility line to which it is being interconnected, as per the table below.

Voltage (kV)	BIL (kV)
34.5	150
13.2	95

4.3. Effective Grounding

Requirements for effective grounding are specified in IEEE Std 1547™-2018 clause 4.12 - Integration with Area EPS Grounding.

The DER interconnection (inclusive of DER assets and interconnecting transformer) must be compatible with the feeder grounding practice at the POI. With some exceptions, installations should meet the requirements for "effectively grounded" as described in IEEE/ANSI C62.92.2 for synchronous machines and C62.92.6 for inverters. Additional grounding requirements identified in the National Electrical Code and local codes shall be met.

The Company may require Supplemental Grounding in the form of a Grounding Transformer or a Neutral Grounding Reactor. The Company will verify the sizing calculation and effectiveness of the Supplemental Grounding during the Effective Grounding and Protection Coordination Study (EGPC Study).

4.4. Open phase Detection

The DER is required to detect, *cease to energize,* and *trip* all phases within 2.0 s for any open phase condition occurring at the RPA, as specified in IEEE Std 1547™-2018 clause 6.2.2 – Open Phase Conditions.

4.5. Cease to Energize

The DER must not deliver active power during steady-state or transient conditions in the *cease to energize* state as specified in IEEE Std 1547™-2018 clause 4.5.

4.6. Control Capability Requirements

The DER must have the ability to respond to external inputs as specified in IEEE Std 1547™-2018 clause 4.6.

4.7. Prioritization of DER Responses

The DER reactive power capability and voltage/power control requirements and response to Area EPS abnormal conditions must be prioritized as specified in IEEE Std 1547™-2018 clause 4.7.

4.8. Isolation Device

A readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DER for all DER with nameplate rating over 25kW. Energy storage devices less than 25kW may also require an isolation device.

4.9. Inadvertent Energization of Area EPS

The DER must not energize the Area EPS if the Area EPS is de-energized, as specified in IEEE Std 1547™-2018 clause 4.9 - Inadvertent Energization of the Area EPS. O&R does not permit intentional Area EPS islands.

4.10. Enter Service

The voltage and frequency settings to be used shall be the default values for voltage and frequency ranges as displayed in Table 4 in IEEE Std 1547™-2018 Clause 4.10.2 – Enter Service Criteria. The default values for delays and ramp rate shall be used as identified in IEEE Std 1547™-2018 Clause 4.10.3 – Performance during entering service for DER with nameplate rating over 50kW.

Enter Service Criteria shall be:

Voltage – Minimum Value:	0.917	p.u.
Voltage – Maximum Value:	1.05	p.u.
Frequency – Minimum Value:	59.5	Hz
Frequency – Maximum Value:	60.1	Hz
Minimum intentional delay:	300	seconds
Enter Service Ramp:	300	seconds

4.10.1 Synchronization

Upon parallel synchronization with the Area EPS, the DER must not cause a step changes in the RMS voltage at the PCC that exceeds 3% of nominal (at medium voltage), or 5% of nominal (at low voltage), as specified in IEEE Std 1547™-2018 clause 4.10.4 - Synchronization.

4.11. DER Interconnect integrity

Requirements for DER Interconnection Integrity are specified in IEEE Std 1547™-2018 clause 4.11 – Interconnect Integrity.

5. DER Support of Grid Voltage

5.1. Reactive Power Capability

Requirements for reactive power capability are specified in IEEE Std 1547™-2018 – Clause 5.2 – Reactive Power Capability of the DER. Category A for rotating machines and Category B for inverters shall be used to determine the appropriate values identified in IEEE Std 1547™-2018.

DER installations 50kW and above may be required to activate reactive power support capability. O&R will make this determination on a case-by-case basis as related to mitigations required by impact studies.

Table 5.1 – Assignment of IEEE 1547-2018 normal performance categories to various types of DERs

Power Conversion	**Prime Mover / Energy Source**	**Category**
Inverter	Solar PV, Battery Energy Storage	Category B
	Wind	Category B
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category A
Induction generator	Hydro	Mutual Agreement

5.2. Reactive Power Control

Requirements for reactive power control mode are specified in IEEE Std 1547™-2018 clause 5.3 - Voltage and Reactive Power Control.

The settings for:

1. Constant Power Factor Mode shall be determined by the CESIR study. Constant reactive power mode settings shall be determined by O&R. The target reactive power level and mode (injection or absorption) will be specified.
2. Voltage Reactive Power (volt-var) mode shall be disabled by default.
3. Active power-reactive power mode settings shall be disabled by default.

5.3. Active Power Control

Requirements for active power control mode are specified in IEEE Std 1547™-2018 clause 5.4 - Voltage and Active Power Control.

Category B DER shall have voltage-active power (volt-watt) mode disabled by default. The settings for the voltage-active power mode shall be determined by O&R.

6. DER Response to Abnormal Conditions

Requirements for DER response to abnormal conditions are specified in IEEE Std 1547™-2018 clause 6 – Response to Area EPS abnormal conditions. The DER shall meet abnormal operating performance category as identified in Clause 6 of IEEE std 1547™-2018.

Table 6.1 – O&R assignment of IEEE 1547-2018 abnormal performance categories to various types of DERs

Power Conversion	**Prime Mover / Energy Source**	**Category**
Inverter	Solar PV, Battery Energy Storage	Category I
	Wind	Mutual Agreement
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category I
Induction generator	Hydro	Mutual Agreement

6.1. Area EPS Faults

The DER shall cease to energize and trip for short-circuit faults on the Area EPS as specified in IEEE Std 1547™-2018 clause 6.2.1 -Area EPS Faults

6.2. Open-Phase Conditions

The DER shall cease to energize and trip within 2.0s for any open phase conditions occurring at the RPA as specified in IEEE Std 1547™-2018 clause 6.2.2 – Open Phase Conditions. O&R ***requires relay protection on inverter-based projects over 300kW for detecting open phase conditions.***

6.3. Area EPS Reclosing Coordination

Requirements for area EPS reclosing coordination are specified in IEEE Std 1547™-2018 clause 6.3 - Area EPS Reclosing Coordination. Appropriate means to ensure that the DER does not expose the utility to unacceptable stresses or disturbances including proper operating DER islanding detection and reclose blocking on an energized circuit.

6.4. Voltage Trip and Ride-through Requirements

Requirements for voltage trip shall be determined by O&R as specified in IEEE Std 1547™-2018 clause 6.4 – Voltage.

Inverter DER shall meet abnormal operating performance Category I as identified in IEEE std 1547™-2018. Synchronous and induction machines shall meet abnormal operating performance Category I. The DER shall trip for default values for under and over voltage and clearing times as identified below:

Shall Trip Function	Voltage (p.u.)	Clearing time (s)
OV2:	1.2	0.16
OV1:	1.1	2.0
UV1:	0.88	2.0
UV2:	0.45	0.16

6.5. Frequency trip and ride-through requirements

Requirements for frequency trip shall be determined by O&R as specified in IEEE Std 1547™-2018, clause 6.5 - Frequency. The DER shall trip for default values for abnormal over and under frequency and clearing times as identified below:

Shall Trip Function	Frequency (Hz)	Clearing time (s)
OF2:	62.0	0.16
OF1:	61.2	300
UF1:	58.5	300
UF2:	56.5	0.16

The parameters of frequency droop operation shall be to their default values as identified in IEEE Std 1547™-2018 Table 24 – "Parameters of frequency-droop (frequency-power) operation for DER of abnormal operating performance Category I".

7. Protection Coordination Requirements

O&R will determine the bus and line configurations and the protection requirements that are necessary to connect the proposed DER. This section provides protection guidelines and requirements of the most used configurations for parallel operation. Protection requirements for a specific facility may be greater than those listed, based on existing system conditions. In the case of larger DER facilities, such as PV with multiple inverters or other certified equipment, additional equipment is often required to provide adequate protection of the T&D system. Requirements for additional protective equipment due to parallel operation of DERs will vary depending on the capacity (MW) of the DER facility and on the configuration of the local Utility system.

O&R shall coordinate all settings of utility-operated protection systems located at the RPA and upstream between the DER and the substation of the bulk power system with the intent of DER performance requirements under abnormal conditions (e.g., ride-through) as specified in IEEE Std 1547™-2018.

Typical protection requirements for all sites are covered in this section. Examples of relay and relay functional requirements for different types and sizes of DER facilities are listed in Appendix C. Typical one-line diagrams are displayed in Appendix D. General protection schemes are further described in Appendix E. This provides basic information on the types of protection schemes necessary for generator Parallel Operation.

7.1. Unintended Islanding Detection

Requirements for unintentional islanding detection are specified in IEEE Std 1547™-2018 clause 8.1 – Unintentional Islanding.

The maximum clearing time for an unintentional island is 2 seconds from the inception of the island.

The utility requires the customer to identify and disclose the method of islanding detection that is being used for all DERs 300 kW and above.

7.2. Transfer Trip Protection

Direct Transfer Trip (DTT) protection schemes shall be evaluated based on minimum loads on the associated feeder and substation bus, including certain fault conditions resulting from system installation to protect for an islanded condition.

7.3. Overcurrent Protection

The DER shall not generate current flow more than the component rating for utility equipment. This is inclusive of allowable, emergency, and fault duty system ratings.

DER protection systems shall include phase and ground fault overcurrent protection. This protection is required to be coordinated with upstream protection devices and must also be coordinated with voltage ride-through requirements.

7.4. Protective Relays (or built-in protection functions)

Interconnection configurations are site and feeder dependent. The utility will determine the protection requirements that are necessary to connect the DER. The types of protection required depend on the DER and the site. Appendix B identifies common DER configurations by size, certification, and type of distribution circuit. Typical protective relay functional requirements are in Appendix C.

7.4.1. Review of Specifications

Manufacturer specifications for frequency and voltage protection schemes must be submitted to O&R for review.

7.5. Telemetry

O&R reserves the right to require telemetry as necessary for monitoring and control to increase reliability. O&R retains the discretion to determine circumstances where smaller DER interconnections are required to install such equipment.

O&R will specify all necessary communication and SCADA requirements for DER interconnection. Specific details of telemetry requirements will be provided at the initial project meeting.

DER facility telemetry monitors and/or controls items are identified in IEEE Std 1547™-2018 – Clause 11 – Interoperability.

Note that special telemetry requirements for Network Service can be found in section 10 and any related interoperability requirements for telemetry are in section 11.

7.6. Other Equipment and Protection Requirements

For customer locations where switchgear is equipped with alternate feeds, and employs automatic-transfer capability, protection shall be provided to block the transfer while DERs are paralleled to the system to prevent an out-of-phase condition. In addition, if required protection is not installed on the customer alternate source, the DER will be tripped before the customer is transferred to the alternative source.

When the DER is fed from an alternative source the DER will be disconnected from the grid.

8. Power Quality

Requirements for power quality are specified in IEEE Std 1547™-2018 clause 7 – Power Quality.

8.1. Limitation of DER DC Injection

The DER must not inject dc current greater than 0.5% of the full rated output current at the RPA as specified in IEEE Std 1547™-2018 clause 7.1 - Limitation of DC Injection.

8.2. Limits on DER Caused Voltage Fluctuations

The DER shall not cause step or ramp rapid voltage changes in the RMS voltage at

the PCC interconnected at medium voltage exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second, or when the PCC is interconnected at low voltage, exceeding 5% of nominal and exceeding 5% per second averaged over a period of one second, as specified in IEEE Std 1547™-2018 clause 7.2.2.

The DER flicker emission to the flicker shall not exceed the greater of the following limits as listed in Table 25, clause 7.2.3: EP_{st} of 0.35 or EP_{lt} of 0.25.

8.3. Limits on Harmonic Distortion from DER

Harmonic current distortion measured at

the *reference point of applicability* (RPA) shall not exceed the limits in Table 26 and Table 27 as specified in IEEE Std 1547™-2018 clause 7.3 - Limitation of Current Distortion.

8.4. Limits on Transient Overvoltages from DER

The DER must not cause the line-to-ground voltage to exceed 138% of its nominal line-to-ground fundamental frequency voltage for greater than one fundamental frequency period as specified in IEEE Std 1547™-2018 clause 7.4 - Limitation of Overvoltage Contribution.

8.5. Maintaining Phase-Voltage Balance

All three-phase DER installations shall not create current unbalance that causes any phase voltage in service to other users to violate O&R requirements for three-phase balance.

9. Grid Integration for Radial-Connected DER

9.1. General Requirements

Integration requirements for radial-connected DERs address compatibility of the DER facility at the RPA (typically PCC) and along the feeder, both on the utility side and customer side of the PCC. Requirements depend on the DER, the location, existing conditions, and capacities of the feeder. Key concerns are maintaining service voltage within limits for all customers, operating within the ratings of power delivery equipment, managing reverse power, addressing contingencies requiring feeder reconfigurations and protection coordination. In this section, limits to the individual and aggregate DER, as well as criteria for feeder upgrades are addressed.

9.2. Distribution Service Transformer Limits

An existing service transformer may need to be upgraded to resolve voltage or capacity problems. The DER interconnection requires a change in the service transformer if the DER output rating is greater than the transformer nameplate rating. Please refer to New York State Standardized Interconnection Requirements and Application Process section II.C.

9.3. Substation Power Transformers Limits

The aggregate of large DER will be limited to 65degree rating plus the minimum day time load minus the 10-year residential forecast for PV growth. An example calculation for a 25MVA substation bank is shown below.

Bank Capacity	
Bank	**380**
Rating	25.000
85%	21.250
65° C rating	23.800
Min Daytime Load	2.253
PV since Min day load	0.031
10-year res forecast	2.698
PV in queue	0.000
Available Capacity	23.324

Available Capacity = (Rating*0.85*1.12) + Min Daytime Load - PV since Min daytime load - 10-year PV forecast -PV in queue

9.4. Thermal Operating Limits

An interconnection shall not thermally overload any electrical equipment based on manufacturer ratings and industry practices for determining limits. Thermal limits shall be based on the DER system rating and customer loads during normal operation. Thermal limits include loading capacity of conductors as determined by size, conductor material, and duct configuration. It also includes circuit and transformer thermal limits.

The calculation for the limit of aggregate DER connected to underground and overhead circuit conductors:

Available capacity for additional DER = (90% of Summer Rating of conductor) *(0.975) – (Aggregate Installed PV on circuit) -(10 year Forecasted DER)- DER in queue

Note: 0.975 accounts for average power factor on the circuit

For example:

Circuit	**Ckt Rating (MVA)**	**90% of Ckt rating (MVA)**	**90% of Ckt rating at .975 PF (MW)**
63-4-13	13.72	12.35	12.04

PV (MW) on Ckt (as 5/15/20)	**10-year Forecast (MW)**	**PV In the Queue beyond today**	**Available Capacity for PV** (90% Ckt rating at .975 PF-PV installed-PV in queue-PV (residential forecast))
0.6098	0.7360	0.0392	10.6524

Available capacity = 13.72*0.9*0.975 - 0.6098 - 0.736 - 0.0392 = 10.65 MW

9.5. DER Customers with Multiple Radial Services

For customers that have multiple normal services, the addition of DERs is limited to avoid any condition where more generation or load is connected to any service than it can accommodate.

9.6. Distribution Automation ("DA") Schemes

The DER shall not interfere with Distribution Automation (DA) schemes. Where DERs may interfere with existing DA schemes the following design requirements shall apply:

s) DERs applying within Distribution Automation zones shall not interfere with the proper operation of the scheme. The range of load and DER output levels must be maintained to ensure proper operation under all conditions. Mitigation techniques may be necessary to meet this requirement.

t) DERs proposed within existing protection and automation schemes must be integrated and interoperable to maintain existing levels of reliability.

9.7. DER Reverse Power Limits

9.7.1. General

Reverse power flows shall not be allowed through any electric system components **not designed** to accommodate it. Distribution components that **may not** be designed to accommodate reverse power flow include:

a) Voltage regulators,

b) Substation metering.

9.7.2. Reverse Power and Integration Margins

Components not specifically designed to accommodate reverse power flow require integration margins to ensure that periods of low load coinciding with periods of high DER generation do not result in reverse power.

10. Grid Integration for Network-connected DER

10.1. General Requirements

O&R's EPS does not contain any spot or area networks.

11. Facility Interoperability

11.1. General Requirements

Requirements for facility interoperability are specified in IEEE Std 1547™-2018 clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

This section defines additional and/or more specific requirements for O&R and clarifies which systems must be connected to telecommunications networks for data to be collected and/or exchanged.

11.2. Interoperability for DER Facilities

O&R reserves the right to use the full information that is identified in these requirements. This interface will be utilized (telemetry connected to a communication network) as specified in other areas of this document and in IEEE Std 1547™-2018 Clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

IEEE Std 1547™-2018 clause 10.7 – Communication protocol requirements gives O&R the option to specify one of three standardized local DER communication interface protocols specified in Table 41 of the standard. O&R specifies the following based on identified criteria:

Table 11.2 – Example assignment of IEEE 1547-2018 local DER communication interface protocols to various types of DERs

Criteria 1: DER Size	Criteria 2: Power Conversion	Examples	Standardized Protocol
Small scale	Inverter	Residential and small commercial Solar PV, Battery Energy Storage	SunSpec Modbus
	Synchronous generator	Small industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	IEEE 1815 (DNP3)
Large scale	Inverter	Solar PV, Battery Energy Storage	IEEE 2030.5
	Synchronous generator	Industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	IEEE 1815 (DNP3)

11.2.1. Unlock Mechanism Requirement

Some DERs have historically included methods to lockout communication through the local interface, usually with passcode access required. Some vendors may continue this practice even after open standards are required. This proprietary step to unlock the device is only allowed for the initial set up and for certification. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means.

For all inverters certified to IEEE 1547™-2018, O&R requires the unlock mechanism be implemented such that:

1. The utility is not locked out of the communication interface. This is the simplest way to ensure future access. It leaves local communication ports open, like local keypad interfaces.
2. Allow devices to be locked but O&R specifies the messages and passcode(s) by which they are unlocked or locked so that there is a known, common way to gain access to all DERs in the service territory.
3. Allow devices to be locked in vendor-proprietary ways but require that customers provide documentation to the utility that describes the messages and passcode(s) for each DER. This is the most complicated method because methods can vary between DERs. Therefore, once the code is entered, the DER must then stay unlocked until O&R locks it again.

O&R prefers the local DER communication interface not to be locked out (option 1) unless another method is mutually agreed upon. If option 2 or 3 is chosen, O&R requires the Customer to provide documentation to the utility for review that describes the messages and passcode(s) for each DER to unlock and relock the DER. If a DER's is shipped with its local DER communication interface locked out, O&R requires the Customer to provide documentation to the utility that describes the messages and passcode(s) for each DER to unlock and relock the DER.

11.3. DER Communication Interface

11.3.1. DER Facility Requirements

The DER facility shall provide all telemetry, control, and associated equipment that is required to meet the telemetry requirements highlighted throughout this document. This equipment includes DER interoperability requirements as well as interoperability with the plant controller. This equipment shall meet O&R specifications.

11.3.2. Orange & Rockland Utilities DER Integrating Protocol and Network Adapters

O&R will provide and install, at customer cost, telemetry, control systems, network adapters, and protection systems required for interoperability of the DER and plant controller with the utility communications and control systems. These systems may include such items as communication systems for monitoring DER information, controlling DERs, tripping DER units, and tripping breakers/reclosers.

11.4. Monitoring, Control, and Information Exchange

All DER shall meet the Requirements for interoperability as specified in IEEE Std 1547™-2018 clause 10 – Interoperability, Information Exchange, Information Models, and Protocols.

"The DER will not be interconnected to the utility communication system at this time. However, O&R reserves the option to interconnect at some future date."

Systems requiring control shall also require monitoring. General requirements for monitoring and control installation in the Customer-Generator facility are, but not limited to:

1. 500 kW to 5 MW connected to the Company's 13.2 kV and 34.5 KV distribution system will require a PCC recloser

- The Company will utilize the PCC Recloser to obtain monitoring data and control for the Company's DSCADA system
- If a PCC recloser cannot be utilized and a dedicated distribution feeder is required the Company will provide a cost to interconnect

2. 50 kW to < 500 kW connected to the Company's 13.2 kV distribution system may require SCADA monitoring sensors
   - Control may be required on case-by-case basis.

3. 0 kW to < 50 kW connected to the Company's 13.2 kV distribution system may require a SCADA monitoring sensor system

12. Facility Revenue Metering

The basic configuration of revenue metering consists of a directional revenue grade meter (import and export) at each point of interconnection with the O&R EPS. Additional separate revenue metering for the gross output of the generation and for auxiliary retail loads may be required, depending on the generation capacity, applicable contractual provisions, and associated tariffs.

All revenue metering equipment must comply with the state public service commission applicable specification sections covering revenue metering, as well as technical requirements for the location provided by O&R.

Metering Requirements:

1) The customer shall install, own, and maintain all facilities necessary to accommodate ORU metering, subject to ORU approval
2) The metering shall be located on the property being served.
    3) ORU will designate the meter location and require transformer cabinets, meter cabinets and all associated equipment be on the exterior of the building with continuous ORU access to facilitate reading and testing.
4) Revenue metering furnished by ORU as well as separate metering on customer generating facilities will be required at all sites.
5) Customer generators may be required to provide a telecommunication line to each O&R owned revenue meter location.
6) Secondary Metered Services under 600 Volts and/or under 500kW DER
    a) Secondary metered service is only available for new facilities under 500kW unless it is connected behind the meter of an existing load customer.
    b) O&R reserves the right to require the customer generating facility to connect to the distribution system through a dedicated transformer. At any time, if it is determined that a new transformer is required, all costs will be the responsibility of the customer as dictated in the Tariff or NY SIR.

c) Secondary service will be provided for single-phase and three-phase as outlined in O&R's General Specification for Electric Installations. Generally, the maximum customer generation that may be connected to a secondary overhead transformer bank will be 500kVA or less (depending on service voltage).
d) The customer should submit detailed plans for inspection and approval by O&R prior to the purchase of any equipment or proceeding with the installation.
e) For locations not previously served, the cost to provide a new transformer (overhead or pad mount) will be the responsibility of the customer as permitted in the Tariff or NY SIR.
f) Non-standard transformers will not be provided or installed by O&R.
g) See the O&R Blue Book for a list of the available service connections.

PHASE	NO. OF WIRES	NOMINAL VOLTAGE	NOTES
1	3	120/240	1
1	3	120/208	2
3	4	208Y/120	3
3	4	240 DELTA/120	4
3	4	480Y/277	5

7) Primary Metered Services over 600 Volts and/or over 500kW DER
a) The customer shall consult O&R where the service voltage may exceed 600 volts.
b) Facilities 500kW or larger shall be metered at the primary voltage level.
c) For primary metered customers, the customer's equipment includes primary metering equipment, high voltage disconnecting overcurrent protective devices, transformers, and all high voltage wiring.

13. Commissioning and Verification Requirements

13.1. General Requirements

Commissioning and verification requirements are specified in IEEE Std 1547™-2018 clause 11 – Test and Verification Requirements. Verification testing in accordance with a written procedure will be required for all installations to ensure the system operates as designed. O&R reserves the right to witness verification testing or require written certification that successful testing was performed.

This section covers several steps in addition to those identified in IEEE Std 1547™-2018 to verify that the interconnection meets requirements. The verification process includes configuration of DER functional setting, evaluation of documentation, determination of tests required to be completed before witness testing. References to determine test requirements that depend on the facility size and type, as well as any specific protective relay test requirements are provided. This section also covers recommissioning and periodic testing.

Specific requirements for each project will be communicated to the customer/developer. These requirements will be a subset of the items found in this section.

13.2. Evaluation of Documentation

Prior to the performance of commissioning tests by qualified personnel, O&R will evaluate the on-site documentation to confirm that it is consistent with the application and other required project documentation. This DER evaluation will determine whether commissioning can proceed and the level of commissioning that is required. Certain commissioning tests need to be completed by the Customer before Witness Testing can take place.

Identification of the commissioning tests to be performed will be dependent on the results of the documentation evaluation prior to commissioning and whether the RPA is at the PCC or PoC as defined by IEEE Std. 1547™-2018. Commissioning tests for DERs with RPA at the PCC shall be performed per IEEE Std. 1547™-2018 “Table 43 – Interconnection test specifications and requirements for DERs that shall meet requirements at the PCC” and as per requirements in IEEE Std. 1547.1™-2020. Commissioning tests for DERs with RPA at the PoC shall be performed per IEEE Std. 1547™-2018 “Table 44 – Interconnection test specifications and requirements for DER that shall meet requirements at the PoC” and as per requirements in IEEE Std. 1547.1™-2020.

13.2.1. Review to Confirm As-Builts

The as installed DER equipment information is required before witness testing for confirmation of consistency with previously provided documentation. This information shall be supplied for the installed DER system and for all DER equipment.

13.3. Configuration of Functional Settings

Prior to commissioning tests, the Customer shall configure the DER facility's functional settings by means of one of the following options:

c) Option A: Selection of a manufacturer-automated profile (MAP)
d) Option B: Use of a configuration and validation toolkit that uses the *local DER communication interface*
e) Option C: Integration with the utility's DER settings requirements or if applicable the utility's DER management system (DERMS)

13.4. DER Commissioning Tests

The DER facility commissioning process shall be planned and carried out by the customer after construction is completed and the site is ready to be energized. At a minimum, the scope of commissioning process to be performed shall include commissioning tests specified by IEEE Std 1547™-2018, clause 11.2.4.3 - DER as-built installation evaluation, clause 11.2.5 - Commissioning tests and verifications, and clause 11.3 - Full and partial conformance testing and verification. The commissioning process shall verify that the facility does not create adverse system impacts the electric grid and to other customers served by the grid.

13.4.1. Facility Commissioning Tests

Commissioning requirements are dependent on the size of the DER, DER certification, and whether the RPA is at the PCC or PoC as identified in IEEE Std 1547™-2018. The following criteria will be considered to identify the commissioning test requirements of the Customer.

- Certification of DER for RPA at PoC or DER System for RPA at PCC. Classifications include DER Unit (PoC), DER Composite for PoC compliance, DER System (PCC), or DER Composite for PCC Compliance.
- Results of DER evaluation by O&R.

Commissioning tests shall be performed according to the appropriate requirements of IEEE Std 1547™-2018 clause 11 and in accordance with IEEE Std. 1547.1™-2020. Clause 11 of IEEE Std 1547™-2018 provides a commissioning requirements matrix. Commissioning tests shall be performed by qualified personnel. For DER systems with plant controllers, commissioning tests shall include the plant controller. The results of the commissioning tests will be evaluated by O&R before Witness Testing can take place.

In addition to the commissioning test requirements identified in IEEE Std 1547™-2018 DER settings shall be verified, and protective relaying shall be tested as identified in Section 13.4.2.- Protective Relay Tests. Commissioning is also required for telemetry systems depending on DER size and application.

Additional commissioning requirements can be found in the commissioning requirements matrix found in Appendix E. The commissioning checklist identifies general commissioning requirements. These requirements are based on common DER configurations and levels as identified in Appendix B. These configuration levels are based on several parameters including:

Facility DER kW - In general, the larger the facility DER kW, the more extensive the commissioning requirements. Different requirements are shown in the checklist in Appendix D for DER 25 kW or less, greater than 25 kW to 250 kW, greater than 250 kW to 2 MW, greater than 2 MW to 10 MW, and greater than 10 MW.

Inverter or rotating machine based DER – Each has unique technology related commissioning requirements

DER unit/system lab certification, partial certification, or not certified – Lab certified inverter based DER units and DER systems are available. Rotating machines and some inverters are not lab certified. DER systems may not be certified even though they use certified DER units. The use of non-certified or partially certified DER units/systems will extensively increase the commissioning requirements.

Exporting or non-exporting – DER units/systems that export power will have more extensive commissioning requirements.

Radial distribution or area/spot network – Area/spot networks have more stringent commissioning requirements than radial distribution networks.

13.4.2. Protective Relay Tests

Qualified testing personnel must perform tests on the Customer's protective relaying prior to energizing from the O&R system. Testing requirements will be evaluated and determined on a case-by-case basis by the Utility, dependent upon the configuration of the proposed generating facility. Portions of the Customer's equipment may be energized when the associated testing for that portion has been completed and verified. The following table is provided to serve as guidance and may or may not be prescribed in the IC's relay equipment inspection requirements.

Table 13.4.2.1 – Testing requirement for relay equipment

Relay Equipment Testing Requirement	Type of Testing
Protection Device Function	Variable – Determined by Relay Type
Acceptance Testing	Test Document Review
Setting Calibration	Witness / Functionality
Tripping Check	Witness / Functionality
Sensing Devices	Test Document Review
Primary Current / Voltage	Witness / Functionality
Telemetry for Protection Scheme	Witness / Functionality

The configuration of settings for the protection systems shall be the settings previously provided by the Customer to O&R and approved by O&R. These settings shall not be altered during commissioning without the authorization of O&R.

13.4.3. Required Witness Tests

Before parallel operation with the Utility System, and after completion of commissioning tests, additional witness testing may be required and inspected by Utility. The Customer is responsible for providing qualified personnel who will complete all required tests. Witness testing is generally required for larger DER. Utility reserves the right to require witness testing in all DER Interconnected scenarios. Witness tests that must be performed in accordance with requirements described above may include:

- Cease-to-energize and trip test
- Anti-islanding
- Reconnection test
- Load Rejection Overvoltage test
- Power Limit functions test
- Radio Frequency Interference test
- Current harmonics test
- Telemetry/SCADA (If applicable)
- Primary Metering
- Direct Transfer Trip (If applicable)
- Reverse power relay (If applicable)

Special commissioning and witness test requirements for secondary networks can be found in Section 10 – Grid integration for network connected DER. For current testing plans for commissioning of DER please refer to Appendix B.

13.5. Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER interconnection.

Circumstances that may lead to event based DER recommissioning include:

f) Change in version of software, software or parameter modifications that change rated values,
g) Replacement of major components or modules with a new version,
h) Required changes in the facility telemetry, or changes in major equipment (e.g., transformers, circuit breakers, etc.),
i) Change in operating mode that was not previously commissioned.

Recommissioning may be scheduled, triggered based on notification of facility change requirements, and may occur due to automated notices of operation outside of expected parameters. These notices may include mis-operation of the DER, mis-operation of protective systems, or excess harmonics detected at the PCC. O&R will determine whether recommissioning may require the full set of tests required of a new facility or a subset of these tests will be sufficient. The level of testing is dependent on the reason for the recommissioning.

13.6. Periodic Testing

Periodic testing may be required as part of the regular testing of basic functionalities of protective and control functions. These tests are expected and may need to occur in time frames typically ranging from every year to every 10 years depending on manufacturers recommendations and O&R’s experience with similar equipment.

Additional requirements for periodic testing are specified in IEEE Std 1547™-2018 clause 11.2.6 - Periodic Tests and Verifications. These requirements include changes in functional software or firmware changes, changes in hardware components of the DER, and changes in protection functions or settings.

13.6.1. Periodic testing Requirements

The Customer must provide O&R with calibration and functional test data for the associated equipment upon request. Minimum intervals are indicated below:

Device	Frequency
Relays	3 years
Communication Channels	3 years
Circuit breakers	5 years
Batteries	Per IEEE 450 - 1995 Standard

The customer must include the identities and qualifications of the personnel who performed the tests. Utility personnel may need to periodically witness the testing.

14. Appendix A: Reference Industry & Agency Standards and Guidelines

14.1. Industry Standards

14.1.1. IEEE Standards 1547, 1547.1, 519, 1453

14.1.2. ANSI C84.1, C62.92, C37

14.1.3. UL 1741

14.1.4. NFPA 850

14.2. Federal Guidelines

14.2.1. FERC Small Generator Interconnection Procedures (SGIP)

14.3. ISO Rules (Large Interconnections)

14.4. NY & NJ State Rules (DER Interconnections)

14.4.1. NYSSIR document

14.4.2. NJ net-metering-and-interconnection

14.5. Industry Association Guidelines

14.5.1. CBEMA and ITIC Requirements

14.5.2. IREC Guidelines, Solar ABCs

15. Appendix B: Orange & Rockland Standards and Guidelines

15.1. Appendix B-1: O&R DER Interconnection Design Package Requirements

Appendix B-1: O&R DER Interconnection Design Package Requirements

15.2. Appendix B-2: O&R CESIR Study Requirements

Appendix B-2: O&R CESIR Study Requirements

15.3. Appendix B-3: O&R EGPC Study Requirements

Appendix B-3: O&R EGPC Study Requirements

15.4. Appendix B-4: O&R CESIR Screens – Methodology & Mitigation

Appendix B-4: O&R CESIR Screens – Methodology & Mitigation

15.5. Appendix B-5: O&R DER Study & Design Requirements Matrix

Appendix B-5: O&R DER Study & Design Requirements Matrix

15.6. Appendix B-6: Supplemental Grounding Sizing Example

Appendix B-6: Supplemental Grounding Sizing Example

15.7. Appendix B-7: O&R Sample Witness Verification Test Report

Appendix B-7: O&R Sample Witness Verification Test Report

15.8. Appendix B-8: O&R Hybrid Single Line Drawings

Appendix B-8: O&R Hybrid Single Line Drawings

15.9. Appendix B-9: O&R Commercial Rooftop PV Schematics

15.9.1. Overview

DER, typically PV, that is installed on a roof of a commercial building that has more than one service, shall not remain energized when any one service is de-energized. The DER may occupy the entire roof if a device such as a recloser or medium voltage switch is installed at the PCC that de-energizes the entire building and DER simultaneously. Approved configurations are shown below (Case 1, 2, 3).

Limitations of Installations on Commercial Rooftops:

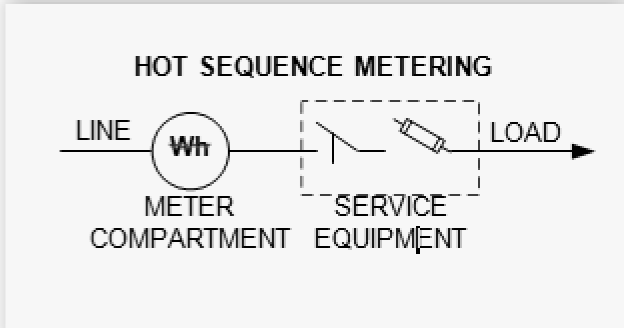
Any solar or battery system installed on a rooftop must not cross any masonry firewalls which divide electrical services in commercial buildings such as strip malls. When the service to a commercial space is disconnected for maintenance or for fire emergencies the DER installed on the roof of that space must also be disconnected.

Appendix B-9 O&R Commercial Rooftop PV Schematics

15.10. Appendix B-10: O&R Design Std.

15.10.1. Primary/Secondary/Aux Metering

DER projects without a load and with nameplate over 500kW (aka "Greenfield" projects) require Primary Metering service. DER projects installed behind an existing load may require a service upgrade and Primary Metering service. All metering at O&R is installed hot sequence except for 480V 200 Amp services. Hot sequence means that electrical disconnects are on the load side of all meters besides the exception. A submeter is required for all auxiliary services. Hybrid Projects using Solar PV and ESS may use an auxiliary service for the ESS with a second meter—this is not mandatory but advantageous for reliability reasons. However, all Hybrid projects require a submeter on the secondary side of the transformer serving the ESS.



15.10.2. Grounding

O&R underground crews use 2/0 tinned copper for ground connections to our grid. The DER site must leave a 36” tail connection of 2/0 copper to allow for grounding connection.

15.10.3. Protection

For DER projects over 300kW a utility grade relay is required. and shunt trip breaker on the customer’s side of the point of connection. One reason is for the detection and disconnecting during an open phase event. The need for a relay on commercial systems from 50kW to 300kW will be determined by O&R on a case-by-case basis.

15.11. Appendix B-11: Useful URLs

- PowerClerk for NY Applications 50kW or Less
- PowerClerk for NY Applications Greater than 50kW
- PowerClerk for NY Community DG Applications
- PowerClerk for NJ Applications
- NYS Department of Public Service – Distributed Generation Information
- SIR Inventory
- O&R Web Page for NY based Interconnection Applications
- O&R Web Page for NJ based Interconnection Applications
- O&R Hosting Capacity Map

16. Appendix C: Common DER Configurations

For Future Use

17. Appendix D: Typical Relay Requirements per Facility Configuration (Radial Circuits)

For Future Use

18. Appendix E: Typical One-Line Diagrams

The following One-Line Diagrams are intended to be typical or representative samples of various types and sizes of generation facilities that are connected to and operate in parallel with the O&R power delivery system and do not purport to cover every possible case. Each site will have to be specifically designed considering the unique characteristics of each installation, the specific location of the Point of Common Coupling and the operating and contractual requirements for that site. Additional ISO/RTO and NERC requirements may also apply.

Appendix E Typical One-Line Diagrams

19. Appendix F: General Protection Requirements

For Future Use

20. Appendix G: Sample Commissioning Checklist

For Future Use

21. Appendix H: Utility-Required Profile for DER Functional Settings

Appendix H: Utility-Required Profile for DER Functional Settings\Appendix H Utility-Required Profile for DER Functional Settings

22. Appendix I: New Business Non-Residential Service Application Process

Appendix I: New Business Non-Residential Service Application Process

23. Appendix J: Guideline for Closed Transition Transfer from and to O&R's Supply

Appendix J: Guideline for Closed Transition Transfer from and to O&R's Supply

24. Appendix K: Solar Site Restoration and Management Specification

Appendix K: Solar Site Restoration and Management Specification