ATCO STANDARD FOR DISTRIBUTED ENERGY RESOURCES

Technical Interconnection Requirements

Revision 1

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ATCO Energy Systems™

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Revision History

Changes to this document are summarized below, with the most recent revision at the top.

Rev.	Issue Date	Approved by	Revision Description
1	2026-JUL-17	Natalie Hilbrecht	4.8.1 Point of Isolation wording order change for clarity. 6.4.1 Mandatory Voltage Requirements. CORRECTION. Update UV1 Machine-Based from 10s to 2 s. Update UV1 Inverter-Based from 2 s to 10 s. 6.5.2.2 Voltage phase angle changes ride-through ADDED. Appendix B updated to align with updated 6.4.1.
0	2025-OCT-30	Natalie Hilbrecht	Initial Release. Combination of Standard for the Interconnection of Generators to ATCO's Distribution System (2002) and Inverter-Based Distributed Energy Resources Technical Interconnection Requirements (2019)

PREFACE

This document replaces document "Standard for the interconnection of Generators to ATCO Electric's Distribution System" (2002) and "Inverter-Based Distributed Energy Resources Technical Interconnection Requirements" (2019). This guide will outline the DER owner's technical and operational requirements for connecting a Distributed Energy Resource to ATCO Electric's distribution network.

DOCUMENT OWNERSHIP

This document is published and controlled by the ATCO Electric's System Planning Group. This document is updated frequently. It is recommended that this document is always accessed through ATCO Electric's website to ensure the most up-to-date information is being used.

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1.0 OVERVIEW

1.1 Purpose

The purpose of the ATCO Standard for Distributed Energy Resource Technical Interconnection Requirements is to:

1. Identify the minimum technical and operating requirements for connecting Distributed Energy Resources to ATCO's distribution facilities.
2. During the interconnection process, additional requirements may need to be met to ensure safe and reliable operation for both the DER owner and ATCO's distribution system.

The Requirements do not:

3. Provide guidelines for connecting to the system at voltages above 25kV. For information on connecting directly to the transmission system, see the requirements provided by the AESO on their website, www.AESO.ca.
4. Provide detailed design information for DER systems. These requirements are not a design handbook, anyone considering the development of a generation facility intended for interconnection to a distribution system should engage qualified individuals to provide consulting and design services.

1.2 Guiding Principles

These requirements were developed in accordance with the following principles:

1. Interconnections must not create a safety hazard for other customers, the public, or operating personnel.
2. Interconnections must not compromise the reliability or restrict the operation of the electric system.
3. Interconnections must not degrade power quality below acceptable levels.

1.3 DER System Certifications

All DER units connected to the distribution system shall be certified as follows:

1.3.1 Inverter Based DER Systems

All inverters connected to ATCO's distribution system shall be UL 1741 SB certified. Proof of certification to be submitted to ATCO prior to energization.

Type III and IV Wind Turbine Generators shall comply with these requirements.

1.3.2 Machine Based DER Systems

All machine type generators connected to ATCO's distribution system shall comply with CSA 22.2 No. 100, UL 2200, and UL 1741 SB. In lieu of UL 1741 SB compliance, IEEE ICAP certification will be accepted.

Type I and II Wind Turbine Generators shall comply with these requirements.

2.0 REFERENCE STANDARDS

This document is based on the latest IEEE, UL, and CSA standards, and the AEUC. It is the DER Owner's responsibility to ensure that the most up to date version of all reference standards are followed during the design, construction, commissioning, operation, and maintenance of the facility. Any discrepancies between this document and the following standards, this document will prevail with supplemental prevalence given to the standard in the order listed below:

	Publisher	Number	Name
1.	IEEE	1547-2018	Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
2.	IEEE	1547.1-2020	Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces
3.	UL	1741 Third Edition including SB	Standard for Safety - Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources
4.	CSA	C22.3 No. 9 - 20	Interconnection of distributed energy resources and electricity supply systems

Additionally, all DER Owners will also need to familiarize themselves and comply with the following standards and regulations:

	Publisher	Number	Name
5.	IEEE	519	Standard for Harmonic Control in Electric Power Systems
6.	IEEE	1453	Standard for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems
7.	IEEE	C62.92.1	Guide for the Application of Neutral Grounding in Electrical Utility Systems Part I: Introduction
8.	IEEE	C62.92.6	Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part VI: Systems Supplied by Current-Regulated Sources
9.	CSA/IEC	61000-3-7	Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems
10.	CSA/IEC	61000-3-14	Electromagnetic compatibility (EMC) - Part 3-14: Assessment of emission limits for harmonics, inter-harmonics, voltage fluctuations, and unbalance for the connection of disturbing installations to LV power systems
11.	CSA	C22.2 No 107.1	Power Conversion Equipment
12.	CSA	C22.1	Canadian Electrical Code Pt.1
13.	CSA	C235	Preferred voltage levels for AC Systems up to 50,000V.
14.	ATCO	-	Electric System Standard for the Installation of New Loads
15.	Government Of Alberta	-	Mirco-Generation Regulation

3.0 DEFINITIONS AND ACRONYMS

Term	Definition
AEUC	The Alberta Electrical Utility Code
AESO	The Alberta Electric System Operator
AIES	The Alberta Interconnected Electric System.
Area EPS	Area Electrical Power System. The electrical grid owned and operated by ATCO.
ATCO	For the purposes of this document, the Distribution Facility Owner ATCO Electric.
AUC	The Alberta Utility Commission.
BESS	Battery Energy Storage System.
Bi-Directional Meter	A meter that measures real and reactive power and energy in both directions.
CEC	The Canadian Standards Association's C22.1 Safety Standard for Electrical Installations Part 1, also known as the Canadian Electrical Code.
Cease to Energize	Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange. This may lead to momentary cessation or trip. This does not necessarily imply, nor exclude disconnection, isolation, or a trip. Limited reactive power exchange may continue as specified, e.g., through filter banks. Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge has been achieved.
CSA	The Canadian Standards Association.
Distributed Energy Resource (DER)	Any resource that is connected to and supplies energy to the distribution system. This includes all types of generation and energy storage.
DER Owner	The entity which owns or leases the Distributed Energy Resource Facility.
DFO	Distribution Facility Owner. In this case, ATCO
Distributed Generation or Distributed Generator (DG)	Unregulated electric generators connected to a distribution system through the Point of Common Coupling (PCC).
Distribution System	Any power line facilities under the operating authority of ATCO. Distribution power line facilities generally operate at or below voltages of 25kV nominal, line to line.
Electric power system (EPS)	Facilities that deliver electric power to a load
Enter service	Begin operation of the DER with an energized Area EPS.
Exporter	An entity which sells electric energy produced within the Province of Alberta to buyers outside the province.
FFR	Fast Frequency Response.
Generator	A device that produces AC power. In the case of inverters, the document uses the term Generator to refer to the AC inverter, not the DC source.

Term	Definition
GFO	Generator Facility Owner. Synonymous with DER Owner
IEEE	The Institute of Electrical and Electronics Engineers, Inc.
Interval Meter	A meter that measures transmission of electric energy and stores data in 15- minute intervals.
Island	A condition in which a portion of ATCO's system which is electrically separated from the rest of ATCO's system is energized by one or more distributed generators
JOA	Joint Operating Agreement
Local EPS	Local Electrical Power System
Load Flow Study	A steady-state computer simulation study of the voltages and currents on the electric system.
NGR	Neutral Grounding Resistor or Neutral Grounding Reactor
Operating Authority	The individual within ATCO's organization and within the DER Owner's organization who is responsible for the safe and orderly operation of electric system facilities.
OVR	Outdoor Vacuum Recloser. An example of a recloser which for the purposes of this document is used interchangeably with recloser
Parallel Operation	The operation of a generation facility while connected to an electric power grid in such a way that both the grid and the generation facilities supply electric power to the loads at the same time.
Point of Common Coupling (PCC)	The point at which ATCO's facilities are connected to the DER Owner's facilities or conductors, and where any transfer of electric energy between the DER Owner and ATCO takes place.
Point of Connection (PoC)	This is the point where the DER is connected to the DER owner's distribution network. This may be a common bus or the PCC in some cases.
Reference Point of Applicability (RPA)	The location where the interconnection and interoperability performance requirements, as well as the protection and control requirements specified in these technical interconnection requirements apply
SOC	System Operating Centre
TFO	Transmission Facility Owner
Transmission System	Any power line facilities under the authority of the Transmission System Owners. Transmission power line facilities generally operate at voltages above 25kV nominal line-to-line.
Trip	Inhibition of immediate return to service, which may involve disconnection. Trip executes or is subsequent to cessation of energization.
Visible-Break Disconnect	A switch or circuit breaker by means of which the generator and all protective devices and control apparatus can be simultaneously disconnected under full load entirely from the circuits supplied by the generator. All blades or moving contacts must be connected to the generator side, and the design of the disconnect must allow adequate visible inspection of all contacts in the open position.

Term	Definition
Wires Owner	The utility that owns the distribution system. In this case ATCO.
Zero-Sequence Continuity	Circuit topology providing continuity between two defined points in the zero-sequence network representation. A transformer that has delta or ungrounded-wye winding in the topological path between the defined points produces discontinuity of the zero-sequence network.

4.0 GENERAL INTERCONNECTION TECHNICAL SPECIFICATIONS AND PERFORMANCE REQUIREMENTS

4.1 Introduction

This standard establishes the minimum requirements for interconnection with ATCO's distribution system. Additional requirements may be needed by both the DER Owner and ATCO to ensure the final interconnection design meets all local and national standards and codes, and that the design is safe for the intended application. The requirements do not address any liability provisions agreed to elsewhere by both parties in a commercial agreement, or through tariff terms and conditions.

The DER Owner shall install, operate, and always maintain in good order and repair in conformity with good electrical practice, the equipment required by this document for the safe parallel operation with ATCO's distribution system.

Interconnecting distributed energy resources can adversely affect the electric service to existing or future customers. The DER Owner must work with ATCO to mitigate any adverse effects. If a DER facility is affecting customers adversely, ATCO may disconnect it until such time as the concern has been mitigated. The DER Owner is responsible for any costs incurred as a result.

4.2 Reference Point of Applicability

The reference point of applicability, or measurement point, is where the performance requirements, operating requirements, protection and control functions, and response to abnormal conditions are required by this standard.

Except as otherwise stated, the RPA for all performance requirements of these requirements shall be the point of common coupling (PCC).

Alternatively, for Local EPSs where all the following conditions are true:

1. Zero sequence continuity is maintained between PCC and PoC
2. No NGRs are installed at the neutrals of the transformers between the PCC and PoC
3. The aggregate DER nameplate rating is less than equal to 500 kVA

then RPA for performance requirements of this standard may be the point of DER connection (PoC), or by mutual agreement between ATCO and the DER operator, at any point between, or including, the PoC and PCC.

4.3 Applicable Voltages

The applicable voltages are determined by the connection to the Area EPS, and the quantities as identified in Table 1 or Table 2 as applicable shall be measured and used in the calculations of protective functions, system performance and power quality.

Table 1: Applicable Voltages When the PCC is Located at Medium Voltage

Area EPS connection at PCC	Applicable voltages
Three-Phase, Four-Wire	Phase-to-phase and phase-to-neutral, or phase-to-phase and phase-to-ground
Three-Phase, Three-Wire, Grounded	Phase-to-phase and phase-to-ground
Three-Phase, Three-Wire, Ungrounded	Phase-to-phase
Single-Phase, Two Wire	Phase-to-2nd wire (the 2nd wire may be either a neutral or a 2nd phase)

Table 2: Applicable Voltages When the PCC is Located at Low Voltage

Low-voltage winding configuration of Area EPS transformer(s)[1]	Applicable voltages
Grounded Wye[2]	Phase-to-phase and phase-to-neutral, or phase-to-phase and phase-to-ground
Ungrounded Wye	Phase-to-phase and phase-to-neutral
Delta[3]	Phase-to-phase
Single-Phase 120/240 V (split-phase)	Line-to-neutral – for 120 V DER systems, or Line-to-line – for 240 V DER systems[4]

[1]A three-phase transformer or a bank of single-phase transformers may be used for three-phase systems.
[2]For 120/208 V two-phase services, line-to-line voltages shall be sufficient.
[3]Including delta with mid tap connection (grounded or ungrounded).
[4]Sensing line-to-neutral on both legs of a 120/240 V split-phase effectively senses the line-to-line and is therefore compliant with this requirement. Sensing line-to-ground may also be used; however, the ground connection should only be used for voltage sensing purposes.

4.4 Measurement Accuracy

All DERs will have measurement capabilities and accuracy that meet or exceed the requirements outlined in Table 3. Transient measurements can be used by protective relays for achieving the mandatory voltage and frequency-tripping requirements of section 6.4.1 and 6.5.1 from IEEE 1547-2018.

Table 3: Minimum Measurement and Calculation Accuracy at the RPA[1]

Measurement	Steady-state Measurements			Transient Measurements		
	Minimum Measurement Accuracy	Measurement Window	Range	Minimum Measurement Accuracy	Measurement Window	Range
Voltage (RMS)	+/- 1% V_{nom}	10 cycles	0.5 p.u. to 1.2 p.u.	+/- 2% V_{nom}	5 cycles	0.5 p.u. to 1.2 p.u.
Frequency[2]	10mHz	60 cycles	50 Hz to 66Hz	100 mHz	5 cycles	50 Hz to 66Hz
Active Power	+/- 5% S_{rated}	10 cycles	0.5 p.u. to 1.2 p.u.	Not Required	N/A	N/A
Reactive Power	+/- 5% S_{rated}	10 cycles	0.5 p.u. to 1.2 p.u.	Not Required	N/A	N/A
Time	1% of measured duration	N/A	5 s to 600 s	2 cycles	N/A	100 ms < 5 s

[1]Measurement accuracy requirements specified in this table are applicable for voltage THD < 2.5% and individual voltage harmonics < 1.5%.
[2]Accuracy requirements for frequency are applicable only when the fundamental voltage is greater than 30% of the nominal voltage.

4.5 Cease to Energize Performance

All DERs connected to ATCO's distribution system shall meet the Cease to Energize requirements identified in IEEE 1547-2018 Section 4.5. In the cease to energize state, the DER shall not deliver active power during steady-state or transient conditions. The requirements for cease to energize shall apply to the point of DER connection (PoC). Alternatively, the requirements for cease to energize may be met be disconnecting from the local EPS. This function is not intended to necessarily meet all requirements for protection, such as direct transfer trip.

4.6 Control Capability Requirements

The DER shall be capable of responding to external inputs as per IEEE 1547-2018 section 4.6. These functions include capability to disable permit service, capability to limit active power, and execution of mode or parameter changes through a local DER communication interface.

ATCO may require a Direct Transfer Trip and/or Runback Scheme after the detailed connection study is performed.

4.7 Prioritization of DER responses

Prioritization of DER responses shall be as per IEEE 1547-2018 Section 4.7.

4.8 Point of Disconnect

All DER facilities will have the means to disconnect and isolate from the distribution system as per Canadian Electrical Code. When the interconnection involves three-phase generators, the disconnect switch must be gang operated to simultaneously isolate all three phases.

All disconnect switches must:

- Simultaneously disconnect all ungrounded conductors of any electric power production source of an interconnected system from all circuits supplied by the electric power production source equipment.
- Simultaneously disconnect all the electric power production sources from ATCO.

Disconnecting means shall meet the following:

- Be capable of being energized from both sides
- Plainly indicate it is in the open or closed position
- Have contact operation verifiable by direct visible means by ATCO
- Have provision for being locked in the open position
- Be capable of being opened at rated load
- Be capable of being closed with safety to the operator with a fault on the system
- Disconnect all ungrounded conductors of the circuit simultaneously.
- Bear a warning to the effect that inside parts can be energized when the disconnecting means is open.
- Be readily accessible.

4.8.1 Point of Isolation

ATCO requires an isolation device to be installed between ATCO and the DER facility on the DER side of the PCC, upstream of all customer owned transformers, DERs, and medium voltage ground sources.

This isolation switch shall be installed for all machine-based generation and whenever the PCC is connected at medium voltage.

This isolation switch shall be installed, owned, and maintained by the DER Owner, and meet all the requirements of a Disconnect switch.

- This switch shall be readily accessible to ATCO operating personnel.
- This switch shall be lockable by ATCO in an open position
- Location specified in an Operating Agreement

4.9 Inadvertent Energization of the Area EPS

The DER shall not energize the Area EPS when the Area EPS is de-energized.

4.10 Enter Service

Prior to entering service, or returning to service after exiting service, the DER must comply with the criteria identified in the following sections.

4.10.1 Enter service criteria

When entering service, the DER shall not energize unless the distribution system voltage and frequency as measured at the PCC are within the limits identified in the Table below and the permit service setting is enabled (when required).

Table 4: Enter Service Criteria for DER of Category I, Category II and Category III

Enter Service Criteria		Default Settings	Range of Allowable Settings
Permit Service		Enabled	Enabled/Disabled
Applicable voltage within range	Minimum Value	≥ 0.917 p.u.	0.88 p.u. to 0.95 p.u.
	Maximum Value	≤ 1.05 p.u.	1.05 p.u. to 1.06 p.u.
Frequency within range	Minimum Value	≥ 59.6 Hz	59.0 Hz to 59.9 Hz
	Maximum Value	≤ 60.1 Hz	60.1 Hz to 61.0 Hz

4.10.2 Performance During Entering Service

When entering service, the DER Facility shall be capable of:

1. Prevent entering service when the permit service setting is disabled or when a Direct Transfer Trip signal is received.
2. Delaying entering service by an adjustable setting with minimum delay when the distribution system steady state voltage and frequency are with allowable ranges identified in Section 4.10.2. The delay shall have the IEEE 1547 default setting range between 0 and 600s with a default value of 300s.
3. The DER shall ramp active power upon entering service at a linear rate or stepwise linear ramp with an average rate of change not exceeding the DER nameplate active power rating divided by the enter service period. The enter service period shall have the IEEE 1547-2018 default value of 300 s with an adjustable range of 1s to 600s. The maximum active power increase of any single step during enter service shall be less than 20% of the DER nameplate active power rating.

For Local EPS that have an aggregate DER rating of less than 500 kVA, individual DER units may increase output of active power with no limitation of the rate-of-change, following an additional randomized time delay with an IEEE 1547-2018 default maximum time random interval of 300 s, and with an adjustable range for the maximum time random interval of 1 s to 1000 s.

Increase of output of active power by Local EPS having an aggregate DER rating of equal to or greater than 500 kVA and increasing output with active power steps greater than 20% of nameplate active power rating shall require approval of ATCO in coordination with AESO.

4.10.3 Synchronization

Any generation facility that can create an AC voltage while separate from the electric system must have synchronization facilities to allow its connection to the electric system.

The DER shall parallel with the Area EPS without causing step changes in the RMS voltage at the PCC exceeding 3% of nominal when the PCC is at medium voltage or exceeding 5% of nominal when the PCC is at low voltage.

Inverter-type, voltage-following equipment that cannot generate an AC voltage while separate from the electric system do not require synchronization facilities; nor do induction generators that act as motors during start-up, drawing power from the electric system before generating their own power.

The DER Owner is responsible for synchronizing and maintaining synchronization to ATCO's system. ATCO's system cannot synchronize to the generation facility.

See table below for maximum allowable frequency, voltage and phase angle limits during synchronization:

Table 5: Synchronizing Parameter Limits for Synchronous Interconnection to the Area EPS

Aggregate Ratings of Generation (kVA)	Frequency Difference (Hz)	Voltage difference (%)	Phase Angle Difference (degrees)
0-500	0.3	10	20
>500-1500	0.2	5	15
>1500-25000	0.1	3	10

4.11 Interconnection Integrity

All DER connections will meet the Electro Magnetic Compatibility requirements identified in ATCO's "System Standard for Installation of New Loads".

4.11.1 Protection from electromagnetic interference (EMI)

All DERs shall be compliant with IEEE C37.90.2 or IEC 61000-4-3.

4.11.2 Surge Withstand Performance

All interconnecting equipment and discrete relays must meet or exceed the requirements of IEEE C62.41.3 Guide for Interactions Between Power System Disturbances and Surge Protective Devices or IEEE C37.90.1 IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems, or CAN/CSA-IEC 61000-4-5.

4.11.3 Paralleling Device

Where a DER facility is allowed to operate as an island while the Area EPS is still in operation, the interconnection protective device, if used as the isolation device, shall be capable of withstanding 220% of the DER rated voltage for an indefinite duration.

4.12 Integration with Distribution System Grounding

DER Facilities shall coordinate their grounding schemes and ground fault protection schemes with the Area EPS. See Section 7.4 Limitation of overvoltage contribution, and for ground fault protection particularly Section 7.4.3 Current Desensitization.

4.12.1 Interconnection Grounding

Grounding configurations must be designed to provide:

- Limitation of Area EPS temporary overvoltage, see Section 7.4 Limitation of overvoltage contribution.
- Suitable fault detection to isolate all sources of fault contribution, including the generators and inverters, from a faulted line on the Area EPS.
- Detection of open phase on the Area EPS

The preferred step-up transformer configuration is a solidly grounded Wye connection on the DER Owner's side of the transformer, and a solidly grounded Wye configuration on ATCO's side of the transformer. This configuration allows detection of Area EPS over voltages at the DER location, zero sequence continuity to allow detection of Area EPS ground faults on a low voltage bus, and to not introduce current desensitizing ground sources. If this configuration is not possible, the configuration chosen must still address the above concerns. The winding configuration for DER interconnection transformers should be reviewed and approved by ATCO prior to sourcing or procuring.

Loss of any supplemental grounding sources such as grounding transformer to maintain an effectively grounded system must trip the DERs to continuously maintain the effectively grounded DER system.

4.13 Exemptions for Emergency and Standby Generators

DERs that form part of an emergency power system as defined by the CEC or a standby power system that is only coupled with the Area EPS during load transfers for 100 ms or less shall not be required to meet the requirements of this standard. DERs for emergency and standby systems can disconnect from the Area EPS and continue to operate without any limitations.

Generators meeting this requirement must apply for Parallel Operation, sign a Joint Operating Agreement and require the following:

- Interconnect Disconnect Device
- Generator Disconnect Device
- Over-voltage Trip
- Under-voltage Trip
- Over/Under Frequency Trip
- Overcurrent
- Ground Over-Voltage Trip or Ground Over-Current Trip
- Synchronizing Check

5.0 REACTIVE POWER CAPABILITY AND VOLTAGE/POWER CONTROL REQUIREMENTS

5.1 Introduction

The following section describes different reactive power and voltage control capabilities that all DERs shall be capable of implementing at the request of ATCO.

All machine based DERs including synchronous, induction, Type I and II Wind Turbine Generators shall meet the requirements of IEEE 1547-2018 Category A for reactive power capability and voltage/power control requirements.

All inverter-based DER including inverters, Type III and IV Wind Turbine Generators shall meet the requirements of IEEE 1547-2018 Category B for reactive power capability and voltage/power control requirements.

5.2 Reactive Power Capability of the DER

Induction Generators do not have reactive power control and consume VARS. Therefore, reactive power compensation must be provided to correct the power factor to meet Category A requirements.

Table 6: Minimum Reactive Power Injection and Absorption Capability

Category	Injection capability as % of nameplate apparent power (kVA) rating	Absorption capability as % of nameplate apparent power (kVA) rating
A (at DER rated voltage)	44	25
B (over +/-5% of PCC nominal voltage range)	44	44

Note: 44% is equivalent to a power factor range of +/-0.9 (i.e. 0.9 lagging and leading) at rated output.

5.3 Voltage and Reactive Power Control

DERs connected to the Area EPS shall be capable of regulating voltage by changing reactive power flows into and out of the facility.

DERs shall be capable of all the Voltage and Reactive Power Control requirements of IEEE 1547 Section 5.3.

By default, the DER shall operate at a constant power factor to be specified by ATCO. If ATCO does not specify a power factor, the default power factor of unity shall be used.

To fulfill this requirement the DER facility shall be capable of operating in the following mutually exclusive control modes:

- Constant power factor mode
- Voltage-reactive power mode
- Active-reactive power mode
- Constant reactive power mode

Synchronous generators shall additionally be equipped with excitation controls capable of controlling output voltage to synchronize to the grid. The voltage control system shall have a stable operating range between 95% and 105% nominal voltage.

5.4 Voltage and Active Power Control

Voltage-active power (volt-watt) mode capability shall be required for both Category A and Category B generation. IEEE 1547-2018 only requires this mode for Category B. See IEEE 1547-2018 Section 5.4 for a description of this mode of operation

This mode shall be disabled by default but will be enabled when ATCO requests with the requested settings.

6.0 RESPONSE TO AREA EPS ABNORMAL CONDITIONS

6.1 Introduction

Abnormal conditions can arise on the Area EPS to which the DER shall appropriately respond. This response contributes to the stability of the Area EPS, safety of utility maintenance personnel and the general public, as well as the avoidance of damage to connected equipment, including the DER.

All machine-based DER including synchronous, induction, Type I and II Wind Turbine Generators shall meet the requirements of IEEE 1547-2018 Category I for response to Area EPS Abnormal Conditions.

All inverter-based DER including inverters, Type III and IV Wind Turbine Generators shall meet the requirements of IEEE 1547-2018 Category II for response to Area EPS Abnormal Conditions.

6.2 Area EPS Faults and Open Phase Conditions

6.2.1 Area EPS Protective Devices

ATCO installs overcurrent protection of a recloser or fuse at all DER interconnections. The recloser may have several protection functions enabled which include phase and neutral time overcurrent (51P/51N), instantaneous phase and neutral overcurrent (50P/50N), directional power (32) and directional overcurrent (67). In certain conditions the recloser may be configured to switch mode only.

ATCO's protection is installed to protect the distribution system only and is not intended to protect the DER facility, including the step-up transformer. It is the DER Owner's responsibility to ensure that all their facility assets are properly protected at all voltage levels and coordinates with the utility protection.

6.2.2 Area EPS Faults

For short circuit faults on the Area EPS circuit section to which the DER is connected, the DER shall cease to energize and trip.

The DER system must be able to cease to energize and trip for the following conditions:

- A short circuit between any phase(s) and ground up to 20 ohms of resistance.
- A short circuit between phase(s).

6.2.3 Open Phase Conditions

All DERs connected to the distribution system shall be capable of detecting an open phase condition to allow single phase switching of the DER and automatically trip all phases and disconnect from the area EPS within 2s.

6.3 Area EPS Reclosing Coordination

To maintain the reliability of the distribution system, ATCO uses automatic reclosing. The DER Owner must take this into consideration when designing generator protection schemes to ensure the generator is disconnected from ATCO's system prior to the automatic reclose of breakers. Reclose times can be 2 s.

6.4 Voltage

6.4.1 Mandatory Voltage Tripping Requirements

The following tables identifies the mandatory voltage tripping requirements for all machine-based and inverter-based DERs connected to the Area EPS. Note that these are different than the default settings in IEEE 1547-2018.

Table 7: Mandatory Voltage Tripping Requirements for Inverter-Based DERs

Trip Function	Voltage (% of nominal voltage)	Clearing time (s)
OV3	120	0.16
OV2	110	2.00
OV1	107	90.00
UV1	88	10.00
UV2	45	0.16

[1] OV1 applies to 150 kW and larger customers only.

Table 8: Mandatory Voltage Tripping Requirements for Machine-Based DERs

Trip Function	Voltage (% of nominal voltage)	Clearing time (s)
OV3	120	0.16
OV2	110	2.00
OV1[1]	107	90.00
UV1	88	2.00
UV2	45	0.16

[1] OV1 applies to 150 kW and larger customers only.

6.4.2 Voltage Disturbance Ride-Through Requirements

The following tables identifies the mandatory voltage ride-through requirements for all machine-based and inverter-based DERs connected to the Area EPS.

Table 9: Mandatory Voltage Ride-Through Requirements for Inverter-Based DERs

Voltage Range (% of nominal Voltage)	Minimum Ride-Through Time (s)	Maximum Response Time (s)	Response
V > 120	N/A[1]	0.16	Cease to Energize
117.5 < V ≤ 120	0.2	N/A	Mandatory Operation
115 < V ≤ 117.5	0.5	N/A	Mandatory Operation
110 < V ≤ 115	1.0	N/A	Mandatory Operation
88 ≤ V < 110	Infinite	N/A	Continuous Operation
65 ≤ V < 88	Linear slope of 8.7 s / 1 p.u. voltage starting at 3 s 0.65 p.u.: $T_{VTR} = 3.0\ s + \frac{8.7\ s}{1\ p.u.}(V - 0.65\ p.u.)$	N/A	Mandatory Operation
45 ≤ V < 65	0.32	N/A	Mandatory Operation
30 ≤ V < 45	0.16	N/A	Mandatory Operation
V < 30	N/A[1]	0.16	Cease to Energize

[1] Cessation of current of DER is not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER.

Table 10: Mandatory Voltage Ride-Through Requirements for Machine-Based DERs

Voltage Range (% of nominal Voltage)	Minimum Ride-Through Time (s)	Maximum Response Time (s)	Response
V > 120	N/A[1]	0.16	Cease to Energize
117.5 < V ≤ 120	0.2	N/A	Mandatory Operation
115 < V ≤ 117.5	0.5	N/A	Mandatory Operation
110 < V ≤ 115	1.0	N/A	Mandatory Operation
88 < V ≤ 110	Infinite	N/A	Continuous Operation
70 ≤ V < 88	Linear slope of 4 s / 1 p.u. voltage starting at 0.7 s 0.7 p.u.: $T_{VTR} = 0.7\text{ s} + \frac{4\,s}{1\,p.u.}(V - 0.7\text{ p.u.})$	N/A	Mandatory Operation
50 ≤ V < 70	0.16	N/A	Mandatory Operation
V < 50	N/A[1]	0.16	Cease to Energize

[1]Cessation of current of DER is not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER.

6.5 Frequency

6.5.1 Mandatory Frequency Tripping Requirements

The following tables identifies the mandatory voltage tripping requirements for all machine-based and inverter-based DERs connected to the Area EPS.

Table 11: Mandatory Frequency Tripping Requirements for all DERs

Trip Function	Frequency (Hz)	Clearing time (s)
OF2	62	0.16
OF1	61.2	300.00
UF1	58.5	300.00
UF2	56.5	0.16

6.5.2 Mandatory Frequency Ride-Through Requirements

The following tables identifies the mandatory frequency tripping requirements for all machine-based and inverter-based DERs connected to the Area EPS.

Table 12: Mandatory Frequency Ride-Through Capability for All DERs

Frequency Range (Hz)	Minimum Ride-Through Time (s)
f > 62.0	N/A
61.2 > f ≤ 62.0	299
58.8 > f ≤ 61.2	Infinite[1]
57.0 > f ≤ 58.8	299
f ≤ 57.0	N/A

[1] Applicable only for a per-unit ratio of voltage/frequency limit of V/f ≤ 1.1.

6.5.2.1 Rate of change of frequency (ROCOF) ride-through

DERs shall meet the Rate of change of frequency (ROCOF) ride-through requirements of IEEE 1547-2018 Section 6.5.2.5. The ROCOF shall be an average rate of change of frequency over an averaging window of at least 0.1 s.

- Machine based generation shall ride through up to a 0.5 Hz/s ROCOF
- Inverter based generation shall ride through up to a 2.0 Hz/s ROCOF.

6.5.2.2 Voltage phase angle changes ride-through

DERs shall meet the Voltage phase angle changes ride-through requirements of IEEE 1547-2018 Section 6.5.2.6 applied to the applicable voltages.

- Multi-phase DER shall ride through for positive sequence angle changes within a sub-cycle to cycle time frame of less than or equal to 20 electrical degrees.
- Multi-phase DER shall remain in operation for change in the phases angle of individual phases less than 60 electrical degrees.
- Single-phase DER shall remain in operation for changes in the phase angle within a sub-cycle to cycle time frame of less than or equal to 60 electrical degrees.

6.5.3 Primary Frequency Response (Frequency Droop)

This function is intended to provide a mechanism through which the DER shall be configured to manage Active Power output in response to the local service frequency.

For DER greater than or equal to 5 MW, primary frequency response shall be enabled for both low-frequency and high-frequency conditions for all DER regardless of Category I or Category II as per AESO requirements. This differs from Section IEEE 1547-2018 where operation for low-frequency conditions for Category I is optional. Default settings from IEEE 1547-2018 shall be used.

For less than 5 MW DER, default settings in IEEE 1547 section 6.5.2.7 will be used. Primary frequency response shall be enabled for Category I DER for high frequency operations. Primary frequency response shall be enabled for Category II DER for both low-frequency and high frequency operation.

Table 13: Frequency Droop Requirements for DER Less Than 5MW

	Category I	Category II
Low frequency	Optional (may)	Mandatory (shall)
High frequency	Mandatory (shall)	Mandatory (shall)

Table 14: Frequency Droop Requirements for DER Greater Than or Equal to 5MW

	Category I	Category II
Low frequency	Mandatory (shall)	Mandatory (shall)
High frequency	Mandatory (shall)	Mandatory (shall)

Table 15: Formula for Primary Frequency Response (Frequency Droop)

Operation for low-frequency conditions	Operation for high-frequency conditions
$p = \min\limits_{f<60-db_{UF}} \left\{ p_{pre} + \frac{(60-db_{UF})-f}{60 \cdot k_{UF}}; p_{avl} \right\}$	$p = \max\limits_{f>60+db_{OF}} \left\{ p_{pre} + \frac{f-(60+db_{OF})}{60 \cdot k_{OF}}; p_{min} \right\}$

Where,

- **P(f)** is the active power output in p.u. of the DER nameplate active power rating as a function of the disturbed system frequency in Hz.
- **f** is the disturbed frequency or applicable frequency in Hz.
- $\mathbf{P_{avl}}$ is the available active power in p.u. of the DER rating.
- $\mathbf{P_{pre}}$ is the pre-disturbance active power output, defined by the active power output at the point of time the frequency exceeds the deadband in p.u. of the DER rating.
- $\mathbf{P_{min}}$ is the minimum active power output due to DER prime mover constraints, in p.u. of the DER active power rating in kW.
- $\mathbf{db_{OF}}$ is the single-sided deadband value for high-frequency, in Hz.
- $\mathbf{db_{UF}}$ is the single-sided deadband value for low-frequency, in Hz.
- $\mathbf{k_{OF}}$ is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop) and is a constant droop for over-frequency events.
- $\mathbf{k_{UF}}$ is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop) and is a constant droop for under-frequency events.

Table 16: Parameters of Frequency-Droop (Frequency/Power) for all DERs[1]

Parameter	Setting
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	.05
$T_{response\ (small\ signal)}$ (s)	5

[1]Note, it is mandatory for all DERs to have the functional capability to meet the frequency-droop (frequency/power) requirements defined in IEEE Standard 1547, as described in this Table 7 above. This functionality must be enabled.

Priority of responses shall follow IEEE 1547-2018 section 4.7.

7.0 POWER QUALITY

The following Section details the power quality constraints that must be maintained at the RPA.

7.1 Limitation of DC Injection

The DER shall not inject DC current greater than 0.5% of the full rated output current at the RPA.

7.2 Limitations of Voltage Fluctuations Induced by the DER

7.2.1 General

The DER shall not create unacceptable voltage fluctuations, rapid voltage change or flicker, at the PCC.

7.2.2 Rapid Voltage Changes (RVC)

When the PCC is at medium voltage, the DER shall not cause step or ramp changes in the rms voltage at the PCC exceeding 3% of nominal voltage and exceeding 3% per second averaged over a period of 1 s.

When the PCC is at low voltage, the DER shall not cause step or ramp changes in the rms voltage at the PCC exceeding 5% of nominal voltage and exceeding 5% per second averaged over a period of 1 s.

These limits do not apply to infrequent events such as transformer energization related to commissioning, fault restoration, or maintenance typically not planned more than once per year.

For infrequent events the IEEE 1453 for RVC the following criteria shall be used:

- The minimum voltage resulting from the event, as measured at the PCC, shall be no less than 0.88 times the initial voltage.
- After 4 cycles, the minimum voltage shall be no less than 0.9 times the initial voltage.
- The initial and final rms voltage at the PCC associated with an event shall be within CSA C235 steady state limits matching ATCO's System Standard for New Loads.

7.2.3 Flicker

Flicker is the subjective impression of fluctuating luminance caused by voltage fluctuations. Assessment methods for flicker are defined in CSA/IEC 61000-3-7. Flicker measurements, for the purpose of performance verification, need to be assessed over a period of one week. This is a test performed by the manufacturer.

$P_{st99\%}$ (99^{th} percentile value) shall not be greater than 0.9

$P_{lt99\%}$ (99^{th} percentile value) shall not be greater than 0.7

If the DER does not meet these requirements, an external compensation device will be required to mitigate the flicker.

P_{st} is defined in IEEE 1453 as the short-term flicker severity. If not specified differently, the P_{st} evaluation time is 10 minutes.

P_{lt} is defined in IEEE 1453 as the long-term flicker severity. If not specified differently, the P_{lt} evaluation time is 2 hours and is obtained from the equation below.

$$P_{lt} = \sqrt[3]{\frac{1}{12}\sum_{i=1}^{12} P_{st_i}^3},$$

where (i = 1, 2, 3 …) are consecutive readings of the short-term severity P_{st}.

7.3 Limitation of Current Distortion

When the DER is serving balanced linear loads, harmonic current injection at the PCC shall not exceed the limits stated below in Tables 6 and 7. The methodology for measuring harmonic and interharmonic values in this requirement is adopted from IEEE Std 519-2022.

Any aggregated interharmonic current distortion between any harmonic frequency *h*+/-5Hz shall be limited to the associated harmonic order *h* limit in Tables 6 and 7. Any aggregated interharmonics current distortion between h+5Hz and (h+1)-5Hz shall be limited to the lesser magnitude limit of *h* and *h*+1 harmonic order.

The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the distribution system without the DER connected. Upon mutual agreement between ATCO and the DER owner/operator the DER may inject harmonic current in excess of Table 6, when it is used as an active filtering device.

Table 17: Maximum Odd Harmonic Current Distortion in Percent of Rated Current

Individual odd harmonic order h	h < 11	11≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	Total Rated Demand Distortion (TRD) up to the h=50 harmonic
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

Table 18: Maximum Even Harmonic Current Distortion in Percent of Rated Current

Individual even harmonic order h	h=2	h=4	h=6	8≤h
Percent (%)	1.0	2.0	3.0	Associated range specified in Table 17

7.4 Limitation of over-voltage contribution (TOV)

7.4.1 Limitation of overvoltage over one fundamental frequency period

The DER shall not contribute to instantaneous or RMS over voltages with the following limits. This shall be with both the DER connected with the utility and with the utility disconnected (for the full fault duration including after the utility has tripped until the DER trips):

1. The DER shall not cause the RMS Line-Ground voltage on any portion of the distribution system that is designed to operate effectively grounded, as defined by IEEE C62.92.1 and IEEE C62.92.6, to exceed 138% of its nominal line-ground RMS voltage for duration of exceeding one fundamental frequency period.
2. The DER shall not cause the L-L RMS voltage to exceed 138% of its nominal L-L RMS voltage for duration of exceeding one fundamental frequency period.
3. The RMS voltage measurements shall be based on one fundamental frequency period.
4. Both Load Rejection Over Voltage (LROV) and Ground Fault Over Voltage (GFOV) must meet these requirements.

7.4.2 Limitation of cumulative instantaneous overvoltage

The DER shall not cause the instantaneous voltage at the PCC to exceed the magnitudes and cumulative durations shown in Figure 6. The cumulative duration shall only include the sum of periods for which the instantaneous voltage exceeds the respective threshold.

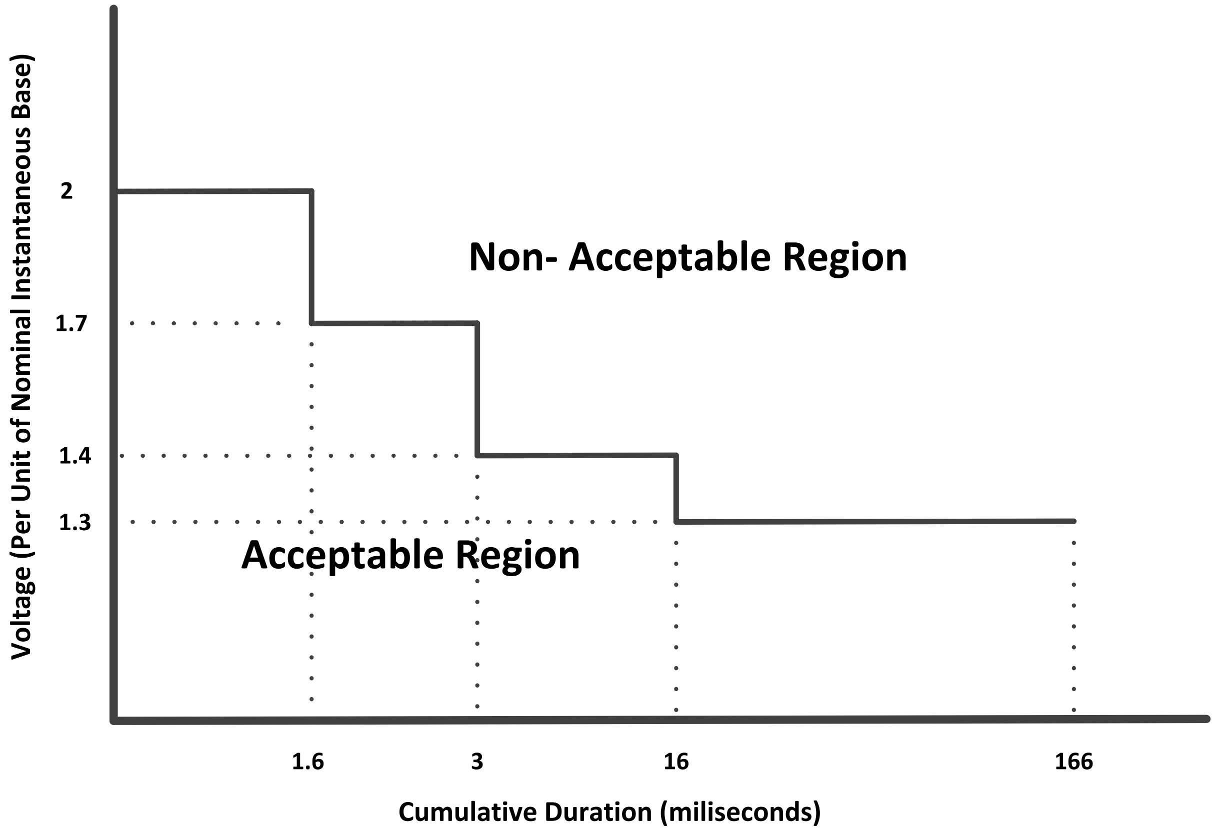


Figure 6. Transient over-voltage limits

To ensure the overvoltage limits for LROV and GFOV are maintained, all machine-based generators regardless of size, and inverter based DER greater than or equal to 150 kW shall demonstrate to ATCO that their system meets the requirements of section 7.4 prior to purchasing of equipment.

For details regarding what information ATCO requires in a TOV Study submission please refer to ATCO's "Effective Grounding, TOV, and Current Desensitization Study Requirements".

7.4.3 Current desensitization

ATCO requires that any DER connected to the system does not desensitize the ground fault protection by more than 10%. Current desensitization can be defined by:

$$DI(\%) = 100\% \times \left(1 - \frac{I_{SCafter}}{I_{SCbefore}}\right)$$

Where $I_{SCafter}$ is the short circuit current seen by the utility protective relay with the DER connected to the system with its output at full capacity. $I_{SCbefore}$ is the short circuit current seen by the utility before the DER connected to the system.

For details regarding what information ATCO requires to demonstrate current desensitization is acceptable please refer to ATCO's "Effective Grounding, TOV, and Current Desensitization Study Requirements".

7.5 Voltage Unbalance

Any three-phase DER must not exceed a phase-to-phase voltage unbalance of 1% at the 25kV PCC, as measured with no load and with balanced three-phase loading. The voltage unbalance definition used in this Guide is derived from NEMA MG1-2021 14.36.2:

Unbalance [%] = 100 x [(maximum deviation from average) / (average)].

Single-phase generators must not adversely unbalance the three-phase system. When they are connected in multiple units, an equal amount of generation capacity must be applied to each phase of a three-phase circuit, and the group of generators must maintain balance when one unit trips or begins generating before or after the others.

A single one-phase generator may be connected alone only if it does not cause voltage unbalance on the distribution system in excess of two per cent.

7.6 Resonance and Self-Excitation

The DER Owner should consider resonance in the design of the generation facility, as certain resonance can cause damage to existing electrical equipment, including the electrical equipment of the DER Owner. Engineering analysis

by the DER Owner should be a part of the design process to evaluate the existence of, and to eliminate the harmful effects of:

1. ferroresonance in the transformer
2. sub-synchronous resonance due to the presence of series capacitor banks; and
3. resonance with other customers' equipment due to the addition of capacitor banks to the distribution system.

If an induction generator is used by DER Owner, the adverse effects of self-excitation of the induction generator during island conditions must be assessed and mitigated. The intent is to detect and eliminate any self-excited condition.

The engineering analysis of resonance and the assessment of the self-excitation effects of induction generators must be submitted to ATCO for approval.

7.7 Power Quality Measurement and Monitoring Requirements

All DERs with a generation capacity over 150 kW will have a power quality meter installed by the DER Owner monitoring the power quality at the PCC. The power quality meter must use metering grade PTs and CTs and can be shared with other metering equipment.

The DER owner will provide ATCO with Power Quality information during the following intervals:

- A seven (7) day period 1 month prior to the DER being connected to the distribution network.
- A seven (7) day period 1 month after the DER is at full output.

This information will be supplied in a report identifying any power quality violations observed during these periods. Report to be authenticated by a Professional Engineer registered with APEGA.

8.0 ISLANDING

8.1 Unintentional Islanding

8.1.1 General

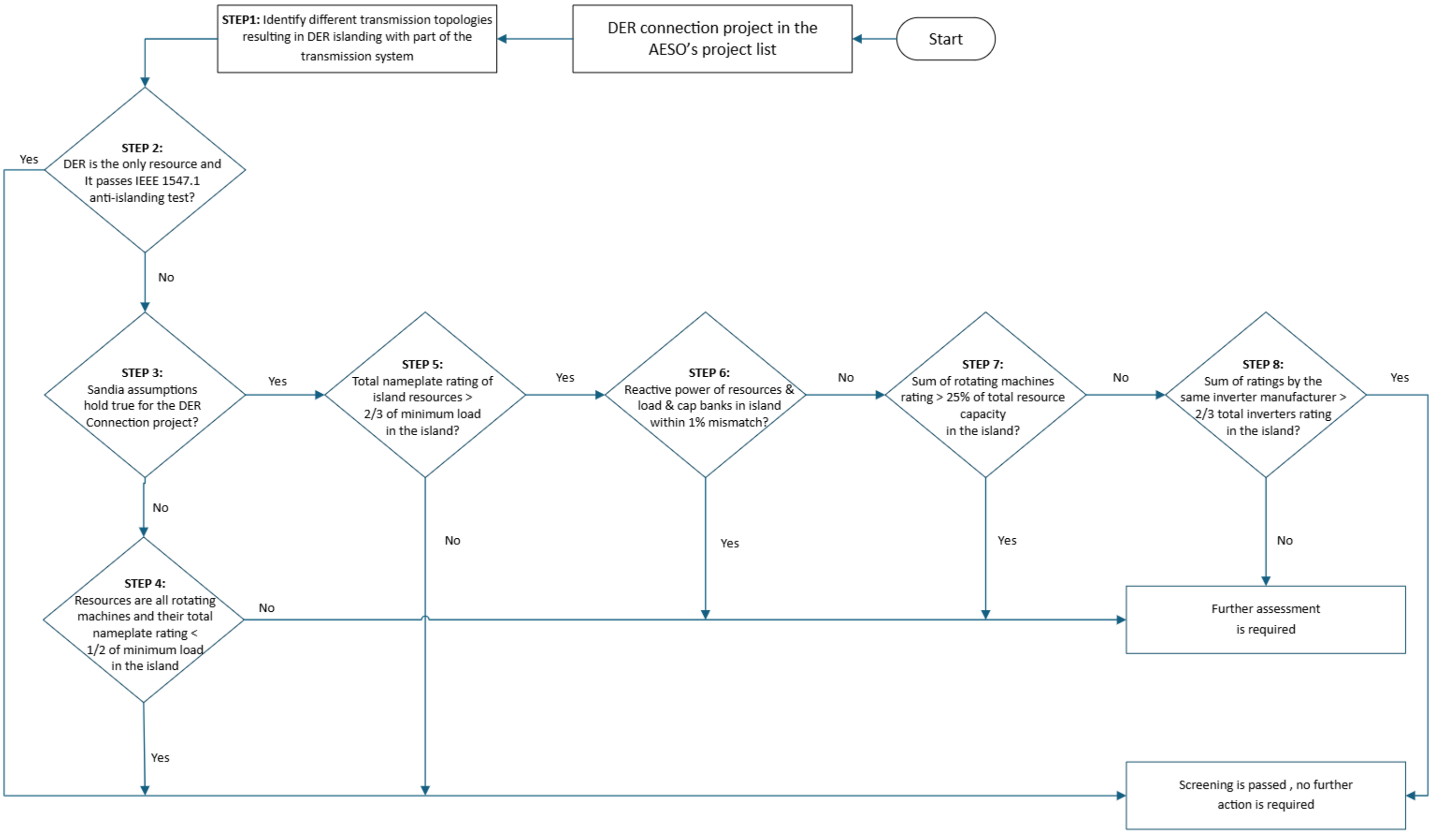
Risk of islanding with a portion of the distribution or transmission system poses risks to personnel and equipment and must be avoided. Islands may be formed when system faults are cleared or during switching operations. Possible islands can be formed by any protective or switching device such as breakers, reclosers, vacuum interrupters, fuses, and switches.

- Unintentional islanding shall be detected and disconnected within 2 seconds unless faster tripping times are specified in a subsequent clause.
- Intentional islanding is not allowed on ATCO's distribution system.
- All machine-based DER 500 kVA and larger shall require a DTT to all potential distribution islands.
- All machine-based DER 500 kVA and smaller shall require a DTT unless generation is below 1/3 the minimum load in the island. This includes islanding through the distribution system with the DER site's load.
- Inverters must be certified to UL 1741 SB and the additional need for DTT shall be assessed by ATCO using the Sandia screening method. See Unintentional Islanding Detection Performance with Mixed DER Types from Sandia National Laboratories.
- Machine based generation with less than 1/3 of the minimum island load may use passive anti-islanding methods for that island with the following conditions:
    - Voltage protection as per Section 6.4.1
    - Frequency protection as per Section 6.5.1
    - Rate of Change of Frequency (ROCOF) must be used with ride-through requirements as per section 6.5.2.1
    - Reverse VAR relays may additional be installed but cannot be relied upon for anti-islanding due to other VAR sources in the island such as capacitors and cable defeating the relays
    - Generator owner must submit an engineered study demonstrating that two independent protection elements detect all potential islands for both fault and switching scenarios tripping within 0.6 s.
    - Passive anti-islanding is dependent on continuous load vs. generation non-detection zones. When a generator no longer meets the criteria for passive islanding even after connection, ATCO may install a DTT at the customer's cost.

An anti-Islanding screening will be conducted for all generators of any size at both the distribution and transmission level, and depending on the results of the study may impact the DTT requirements for an installation.

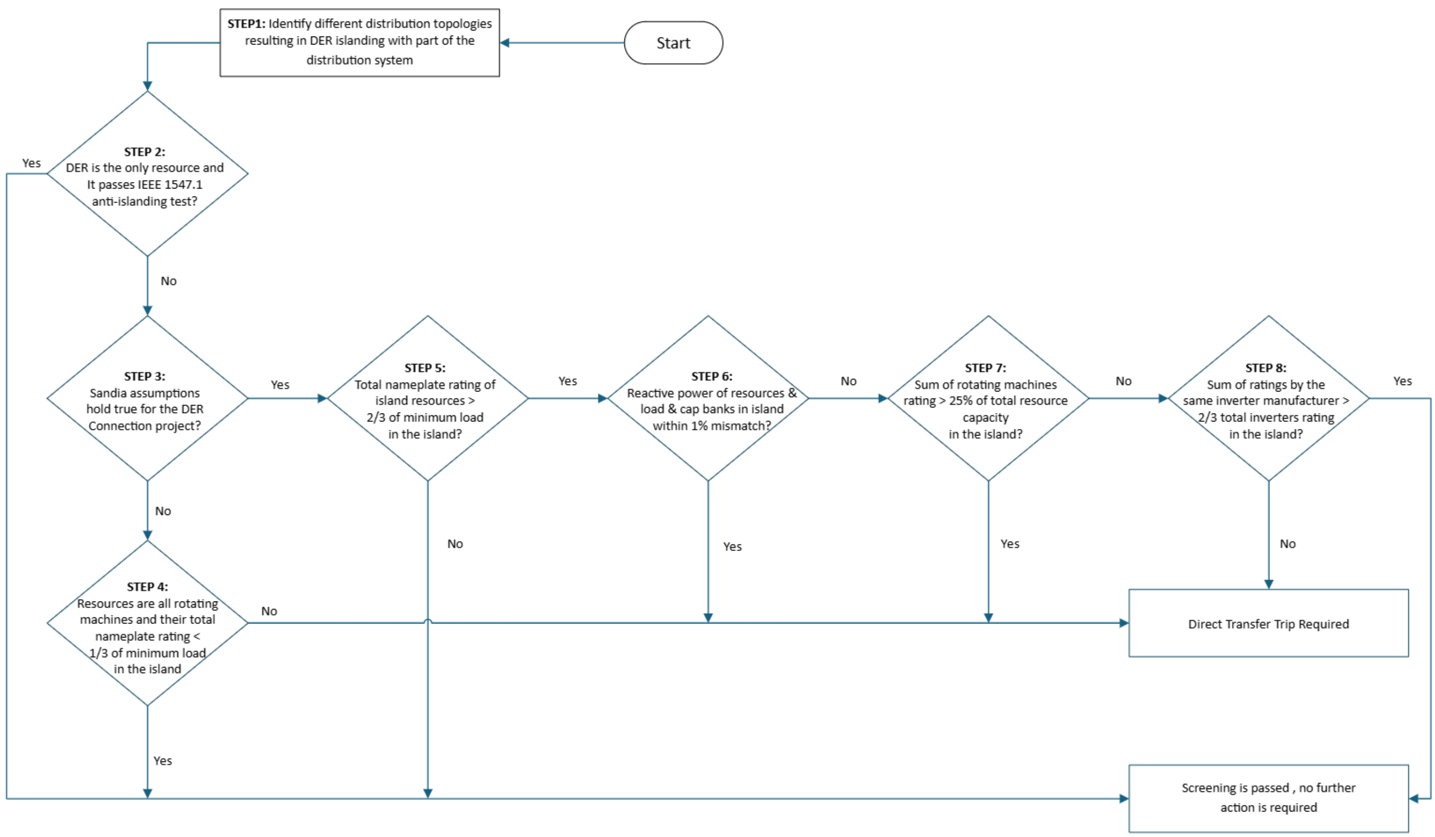
The screening for Transmission islands in ATCO's study follows the anti-islanding screening in the "DER Anti-Islanding Screening and Study Guideline" 2023 version published by the AESO. Refer to the AESO guide for further details. This method uses a 1/2 min load to generation ratio for islands involving only rotating machines and the SANDIA screening method for islands involving inverters with active anti-islanding or mixed inverter and rotating machines.

Figure 1: AESO Anti-Islanding Screening for Transmission Islands



The criteria for mitigating Distribution islands follows the anti-islanding screening for rotating machines as per IEEE 1547.2 of 1/3 min load to generation ratio for rotating machines and uses the SANDIA screening method for islands involving inverters with active anti-islanding or mixed inverter and rotating machines. Minimum size of generation screening is for all islands since minimum loading can happen in switching islands of all sizes of minimum load. If anti-islanding screening fails, Direct Transfer Trip must be applied, or the anti-islanding criteria shall be reassessed after changing anti-islanding technology to have UL 1741 SB compliance.

Figure 2: ATCO Anti-Islanding Criteria for Distribution Islands



8.1.2 Direct Transfer Trip

Depending on the results of the distribution and transmission anti-islanding criteria, ATCO may require a communication-based signal to trip the DER from the Area EPS.

The DTT signal is typically sent to the DER Owner's Point of Connection breaker, but in some special cases where the DER Owner wants to operate as an island within their local EPS, the customer's PCC breaker may be used instead at DER owner request.

DER owners that are required to have DTT interconnections shall have a synchronizing interface breaker relay capable of receiving SEL mirrored bit protocol. The DER Owner will be responsible for all required programming of their relay to ensure it conforms to the joint operating agreement. DTT schemes must be programmed fail safe.

- When a DTT signal is received, the DER facility shall trip off within 0.6s to conform with the designed reclosing interval of automatic devices on the distribution line, and fault clearing times for ATCO's system.
- If a communication failure occurs between the DER Owner's site and ATCO's DTT communication network, the DER facility must detect and trip the DER within 2s.

All DERs requiring a DTT must also have breaker fail protection in place. A second breaker on the customer's facility will be used to receive the breaker fail signal and trip the DER from the Area EPS. If there is a recloser available on the utility side of the PCC to receive a breaker fail signal, ATCO may allow a communication interconnection to trip the utility recloser in lieu of a second customer owned breaker.

8.1.3 Runback Scheme

During ATCO's study process, if it is determined that a DER facility has the potential to overload the distribution or transmission system, a communication-based runback scheme sending a runback signal to the DER may be required.

8.2 Intentional Islanding

Intentional islands are not allowed to operate within ATCO's Area EPS. Any exceptions, such as a local EPS within an Industrial Service Designation, or a utility owned microgrid requires ATCO's approval.

9.0 SCADA VISIBILITY AND CONTROL

9.1 DER Real-time Supervisory Control and Visibility

Visibility and Control of DERs is defined as the remote monitoring and control of DER's operation from the control device. Monitoring may include connection status, real power output, reactive power output, voltage at the point of interconnection and other readings as required.

DER facilities with an aggregate nameplate capacity of 5 MW or more (regardless of export capability/limitations) are required to provide visibility to the Alberta Electric System Operator (AESO) and to ATCO's SOC. This requirement consists of providing SCADA data that is communicated to the AESO System Operating Centre.

ATCO may require additional SCADA requirements at the time of interconnection application. To ensure compatibility with ATCO's existing control and monitoring platform ATCO shall specify the allowable communications protocols, and acceptable communications equipment that will be used for monitoring the operation of the DER.

10.0 REVENUE METERING

10.1 Responsibility

Unless otherwise agreed upon, the following apply to all DER Owners:

- ATCO will be responsible for providing and installing appropriate metering facilities to measure energy produced by the DER facility, and consumption of power flowing from the distribution system to the DER facility. The metering facilities will comply with Measurement Canada (MC), AESO, AUC and ATCO standards.
- ATCO will be responsible for interrogating the meter in accordance with AUC Rule 021 requirements of a Meter Data Manager with respect to the metered power production and consumption information.

10.2 Access to Meters

If the DER Owner requires access to revenue meter data, they shall notify ATCO during the detailed project planning process to ensure the proper meter can be purchased for their site.

11.0 LIMITED EXPORT AND NON-EXPORT

For sites that are adding generation to support existing loads while running parallel to the grid but not exporting energy under normal operating conditions, the DER Owner will be required to adhere to the following:

- Generator Rejection
  - The impact of customer generator rejection must be evaluated by the customer and may require the DER owner needing to trip their load upon DER tripping if a Rapid Voltage Change exceeding infrequent limits as per Section 7.2.2 occurs.
- Rules around tripping or curtailing
  - Customer is required to decrease generation to ensure no power is exported. Further requirements will be stated in the Joint Operating Agreement.
  - Overload of ATCO equipment is not allowed during tripping of site load or generation within the customer island. Overload protection will be installed to trip the customer site if overload limits are reached.
  - Overload protection shall be installed by the customer to prevent overloading of customer equipment and transformers.
  - All non-export generators will undergo an anti-islanding evaluation.
    - DTT may be required to ATCO's devices even if not injecting power, due to the increased likelihood of islanding due to a close load to generation match
  - A 32R relay shall be set to trip within 10 s if the export power raises above the export limit. Consideration should be given by the DER Owner for measurement accuracy.
  - A 67/67N relay may be required at the discretion of ATCO. If required the pickup shall be the rated current of the export limit and the trip time shall be 5 second, unless otherwise specified by ATCO. Consideration should be given by the DER Owner for measurement accuracy.

12.0 TESTING AND COMMISSIONING

12.1 General

The DER Owner must notify ATCO in writing at least two weeks prior to the initial energization and start-up testing of the DER Owner's generation facility, and ATCO may witness the testing of any equipment and protective systems associated with the interconnection.

The tests and testing procedures must align with the requirements specified in IEEE 1547-2018 clause 11 and IEEE 1547.1-2020.

This section is divided into type testing and verification testing:

- A type testing is performed or witnessed once by an independent testing laboratory for a specific protection package. Once a package meets the type testing criteria described in this section, the design is accepted by ATCO. If any changes are made to the hardware, software, firmware or verification test procedures, the manufacturer must notify the independent testing laboratory to determine what, if any, parts of the type testing must be repeated. Failure of the manufacturer to notify the independent testing laboratory of any changes may result in withdrawal of approval and disconnection of units installed after the change was made.

- Verification testing is site-specific, periodic testing to assure continued acceptable performance.

These testing procedures apply only to devices and packages associated with protection of the interconnection between the generation facility and ATCO's system. Interconnection protection is usually limited to voltage relays, frequency relays, synchronizing relays, reverse current or power relays and anti-islanding schemes. Testing of relays or devices associated specifically with protection or control of generating equipment is recommended but not required unless the devices impact the interconnection protection.

Protection testing must include procedures to functionally test all protective components of the protection scheme, up to and including tripping of the generator and/or PCC. The testing must verify all protective set points and relay/breaker trip timing.

12.2 Type Testing

All interconnection equipment must include a type testing procedure as part of the documentation. The type testing must determine if the protection settings meet the requirements of this Standard.

Prior to type testing, all batteries must be disconnected or removed for a minimum of 10 minutes. This test will verify the system has a non-volatile memory and that the protection settings are not lost. A test must also be performed to determine that the failure of any battery used to supply trip power will result in an automatic shutdown.

Inverters must, at the time of production, meet or exceed the requirements of UL 1741 SB.

12.3 Verification Testing

Prior to parallel operation of a generation facility, or whenever the interconnection hardware or software is changed, verification testing must be performed. The verification test must be performed by a qualified individual in accordance with the manufacturer's published test procedure. Qualified individuals include licensed professional engineers, factory-trained or certified technicians and licensed electricians experienced in testing protective equipment. ATCO reserves the right to witness the verification test or to require written certification that the test was performed.

Verification testing must be performed annually. All verification tests prescribed by the manufacturer or developed by the DER Owner and agreed to by ATCO must be performed. The DER Owner is responsible for maintaining the verification test reports for inspection by ATCO.

Inverter generator operation must be verified annually, by operating the load break disconnect switch and verifying that the generation facility automatically shuts down and does not restart for five minutes after the switch is closed.

Any system that depends on a battery for trip power must be checked for proper voltage and logged monthly. Once every four years, the battery must either be replaced, or a discharge test performed.

12.4 Protective Function Testing

Protection settings that have been changed after factory testing must be field verified to show that the device trips at the measured (actual) voltage and frequency. Tests must be performed using secondary injection, applied waveforms or a simulated utility. Alternatively, if none of the preceding tests can reasonably be done, a settings adjustment test can be performed if the unit provides discrete readouts of the settings.

The non-islanding function, if available, must be checked by operating a load break switch to verify that the interconnection facility ceases to energize its output terminals and does not restart for the required time delay after the switch is closed.

A reverse power or minimum power function, if used to meet the interconnection requirements, must be tested using secondary injection techniques. Alternatively, this function can be tested by means of a local load trip test or by adjusting the DER output and local loads to verify that the applicable non-export criterion (i.e., reverse power or minimum power) is met.

12.5 Verification of Final Protective Settings Test

If protective function settings have been adjusted as part of the commissioning process, then, at the completion of the adjustment, the DER Operating Authority must confirm all devices are set to ATCO's approved settings.

Interconnection protective devices that have not previously been tested as part of the interconnection facility with their associated instrument transformers, or that are wired in the field, must be given an in-service test during commissioning. This test is to verify proper wiring, polarity, sensing signals, CT/PT ratios and operation of the measuring circuits.

For protective devices with built-in metering functions that report current and voltage magnitudes and phase angles or magnitudes of current, voltage, and real and reactive power, the metered values can be compared to the expected values. Alternatively, calibrated portable ammeters, voltmeters and phase-angle meters may be used.

12.6 Hardware and Software Changes

Whenever changes are made to interconnection hardware or software that can affect the functions listed below, the potentially affected functions must be retested:

- Over-voltage and under-voltage.
- Over-frequency and under-frequency.
- Non-islanding function (if applicable).
- Reverse or minimum power function (if applicable).
- Inability to energize deadline.
- Time delay restart after ATCO outage.
- Fault detection, if used.
- Synchronizing controls (if applicable).

To ensure that commissioning tests are performed correctly, ATCO may wish to witness the tests and receive written certification of the results. Reports stamped by an engineer may be required.

Refer to Appendix B for an example of a protective device setting commissioning sheet.

12.7 Switchgear

ATCO reserves the right to witness the testing of installed switchgear. The DER Owner must notify ATCO two weeks in advance of any testing.

13.0 DATA REQUIREMENTS

The following table identifies the drawings and data the DER Owner is required to submit to ATCO when applying for interconnection the Area EPS.

Table 19: Required Documentation Summary

Drawing/Data	Proposal	Approval[1]	Verified
Manufacturer's equipment data sheet			X
Control Schematic		X	X
Single Line Diagram indicating proposed protection settings	X	X	X
Description of protection scheme	X	X	X
Generator nameplate schedule		X	X
Fuse and protective relay coordination study and settings		X	X
Current transformer characteristic curves		X	X
Commissioning report c/w protection settings			X
Plot plan showing location of lockable, visible disconnect switch	X	X	X

[1]The minimum time requirement for reviewing this information is generally 10 working days.

14.0 OPERATING REQUIREMENTS

It is required to operate within the JOA and keep the contact information and SLD up to date.

14.1 Operating Authority

ATCO and the DER Owner must each identify, by name or by job title, the individual within their organizations who is their "Operating Authority." The Operating Authority is the person designated to make policy decisions affecting the equipment within the facility and is responsible for establishing operating procedures and standards within each organization. The Operating Authority ensures the accuracy of the appropriate sections and contact information, signs the Joint Operating Agreement described in section 3.2 and ensure that the SLD and contact information are updated as necessary throughout the lifecycle of the interconnected facility.

This individual also ensures that the Operator in Charge (see below) is competent to operate their respective system and is aware of the provisions of any operating agreements and any regulations relating to the safe operation of the electrical system that may apply.

14.2 Operator in Charge

ATCO and the DER Owner must each identify the individual, by name or by job title, who is the "Operator in Charge" (OIC) of their facilities and operates their portion of the interconnection facility. The OIC is responsible for the real time operation of the power system or portion thereof, in accordance with the requirements of established safety standards, operating standards and procedures. This individual must be familiar with the Joint Operating Agreement, and aware of the provisions of any other operating agreements and any regulations that may apply. The Operating Authority and the Operator in Charge may be the same person.

14.3 Joint Operating Agreements

A Joint Operating Agreement must be established between ATCO and the DER Owner to provide for the safe and orderly operation of the interconnection facility. The Agreement must include, but is not necessarily limited to, the following:

1. A high-level technical description of the DER Owner's generation facility, equipment, and protection.
2. A high-level technical description of ATCO's distribution system facilities and protection.
3. Clear documentation of ownership, interface boundaries and points of isolation.
4. A description of how the generation facility will operate (e.g., parallel or islanded).
5. Clear roles and responsibilities for the Operating Authority and OIC
6. The name, title and telephone number(s) of the Operating Authority and the Operator in Charge for each party to the Agreement.
7. Provision for ATCO to disconnect the generation facility if it fails to meet technical and/or power quality requirements, or if the operation of the generation facility is or may become dangerous to life or property.
8. Reference to safety procedures for joint work and terminology between OICs.
9. Identification of responsibility for maintaining current operating information.
10. Isolation procedures for work on the facilities (e.g. mutual lock and tag).
11. Site Access agreement
12. Notification requirements for planned outages and procedures for emergency outages.
13. Outage and work permit procedures.
14. Coordination after contingencies and prior to restoration including any synchronization.
15. Maintenance activity or switching that require the DER to trip.
16. Any control setting parameters that could affect the interconnection (e.g., voltage and frequency).
17. Any transmission remedial action schemes, anti-islanding or special protection schemes for the DER interconnection.
18. The approval of both ATCO and the DER Owner.

15.0 MAINTENANCE

All the equipment, from the generator up to and including the PCC, is the responsibility of the DER Owner.

The DER Owner must maintain the equipment to accepted industry standards, in particular Part 1, paragraph 2-300 of the CEC. Failure to do so may result in disconnection of the generator.

The DER Owner must present the planned maintenance procedures and a maintenance schedule for the interconnection protection equipment to ATCO and keep records of such maintenance.

APPENDIX A - PROTECTION REQUIREMENTS

Table A1 – Protection Requirements for Single Phase Generators

Table A2 – Protection Requirement s for Three Phase Generators

Table A3 – Protection Requirements for Closed Transition Switching of Stand-alone Generators

Table A1 – Protection Requirements for Single Phase Generators

Protection Function/Device	50 kW or less
Interconnect Disconnect Device	X
Generator Disconnect Device	X
Over-voltage trip	X
Under-voltage trip	X
Over-frequency trip	X
Under-frequency trip	X
Overcurrent	X
Synchronism check (note 1)	X
Anti-islanding protection	X

Notes:

1. Only automatic synchronism check schemes will be accepted.
2. This table outlines the minimum requirements for connection to the distribution system. ATCO may request additional protection functions at their discretion after a review of each case.

Table A2 – Protection Requirements for Three Phase Generators

Device/Function		DER Size	
		<150kW	>150kW
25	Synchronizing Check	X (note 1)	X (note 1)
27	Under-voltage	X	X
32	Directional Power	X (note 2)	X (note 2)
50BF	Breaker Fail	X (note 7)	X
50P	Phase Instantaneous Overcurrent	X (note 3)	X (note 3)
51P	Phase Timed Overcurrent	X	X
50N	Neutral Instantaneous Overcurrent		X (note 3)
51N	Neutral Timed Overcurrent		X
59	Over-voltage	X	X
67P	Directional Phase Overcurrent	X (note 2)	X (note 2)
67N	Directional Neutral Overcurrent		X (note 2)
81O	Over Frequency	X	X
81U	Under Frequency	X	X
	Interconnect Disconnect Device	X	X
	Generator Disconnect	X	X
	Anti-Islanding Protection	X	X
	Return to Service Delay	X	X
	Open Phase Detection	X	X
	Direct Transfer Trip	X (note 4,5)	X (note 4,5)
	Loss of Grounding Transformer	X (note 6)	X (note 6)

NOTES:

1. Required for all grid connected generators except inverter type voltage following equipment that cannot generate AC voltage or induction machines that act like motors during startup. All synchronizing schemes to be automatic, manual synchronization will not be permitted.
2. Required for non-export sites where the generator supplies site load only while interconnected with the grid. Either directional power (46) or directional overcurrent (67) schemes can be used by the DER Owner.
3. Instantaneous elements to be used as required by DER Owner for coordination and protection purposes.
4. Synchronous generators over 150kW will require a DTT scheme. Inverter based DERs will be assessed on a case-by-case basis and DTT requirement will be identified in the Phase 1 transmission study.
5. Customers with NGRs at their site who require transfer trip schemes that trip ATCO's upstream protection in the event of a ground fault should make this requirement know to ATCO at the start of the project so that the proper equipment can be provided for the project.
6. Applies to system that require a grounding transformer to maintaining effective grounding. This protection scheme will detect that the grounding transformer is no longer connected to the system and disconnect the DER from distribution system.
7. Breaker fail only required when a DTT is needed for the interconnection.

Table A3 – Protection Requirements for Closed Transition Switching of Stand-alone Generators

Protection Function or Device	Generator Size 10MW or less
Interconnect Disconnect Device	X
Generator Disconnect Device	X
Over-voltage trip	X
Under-voltage trip	X
Over-frequency trip	X
Under-frequency trip	X
Phase Overcurrent	X
Ground Overcurrent	X
Synchronism check	X

Notes:

1. This table applies generators connected to the grid for 6 cycles or less during closed transition switching operations.
2. All generators that will have a closed transition switching scheme are required to receive permission from ATCO prior to putting the scheme into service. Owners are required to apply to ATCO as part of their connection to ATCO.

APPENDIX B – SAMPLE COMMISSIONING CHECKLIST

<table>
<tr><td colspan="2">ATCO Project #</td><td></td><td colspan="2">Date</td><td></td></tr>
<tr><td colspan="2">Substation</td><td></td><td colspan="2">Feeder</td><td></td></tr>
<tr><td colspan="2">Facility Status</td><td>☐ New</td><td colspan="2">☐ Upgrade</td><td>☐ Existing</td></tr>
<tr><td>Aggregate Generation Capacity</td><td></td><td>Generation Type</td><td></td><td>Facility Nominal Voltage (VAC)</td><td></td></tr>
<tr><td colspan="2">Interconnection Device Identifier (Per SLD)</td><td></td><td colspan="2">Associated Relay Identifier (Per SLD)</td><td></td></tr>
<tr><td colspan="2">Relay Manufacturer</td><td></td><td colspan="2">Relay Model</td><td></td></tr>
<tr><td colspan="2">Inverter certified to UL1741 SB</td><td>☐</td><td colspan="2">Machine certified to UL2200</td><td>☐</td></tr>
</table>

Phase/Ground Overcurrent					
Function	**Curve**	**Pickup (primary amps)**	**Time Dial**	**Time Adder/Delay (s)**	**Testing Passed**
51P					
50P	-		-		
51G					
50G	-		-		

Directional Elements						
Function	**Curve**	**Pickup (primary A or primary kW)**	**Time Dial**	**Time Adder/Delay (s)**	**Trip Direction (to DER or to ATCO)**	**Testing Passed**
32						
67						
67N						

Over/Under Voltage Elements					
Function	As Left Settings		Nominal Settings		Test
	Pickup (% of nominal voltage)	Delay (s)	Pickup (% of nominal voltage)	Clearing time (s)	Measured Clearing Time (s)
OV3			120	0.16	
OV2			110	2	
OV1[1]			107	90	
UV1			88	10 (Inverter-Based) 2 (Machine-Based)	
UV2			45	0.16	

[1] OV1 applies to 150 kW and larger customers only.

Over/Under Frequency Elements					
Trip function	As Left Settings		Nominal Settings		Test
	Pickup Frequency (Hz)	Delay (s)	Pickup Frequency (Hz)	Clearing Time (s)	Measured Clearing Time (s)
OF2			62	0.16	
OF1			61.2	300	
UF1			58.5	300	
UF2			56.5	0.16	

Voltage Ride-Through Verification for Inverter-Based DER				
Voltage Range (% of nominal voltage)	Minimum ride-through time (s)	Maximum response time (s) (design criteria)	Response	Measured Response Time (s)
V > 120	N/A	0.16	Cease to energize	
117.5 < V ≤ 120	0.2	N/A	Mandatory operation	
115 < V ≤ 117.5	0.5	N/A	Mandatory operation	
110 < V ≤ 115	1	N/A	Mandatory operation	
88 ≤ V ≤ 110	infinite	N/A	Continuous operation	

Voltage Ride-Through Verification for Inverter-Based DER				
65 ≤ V < 88	$T_{VTR} = 3.0s + \frac{8.7s}{1p.u.}(V - 0.65p.u.)$	N/A	Mandatory operation	
45 ≤ V < 65	0.32	N/A	Mandatory operation	
30 ≤ V < 45	0.16	N/A	Mandatory operation	
V < 30	N/A	0.16	Cease to energize	
Ride-Through Verification for Machine-Based DER				
V > 120	N/A	0.16	Cease to energize	
117.5 < V ≤ 120	0.2	N/A	Mandatory operation	
115 < V ≤ 117.5	0.5	N/A	Mandatory operation	
110 < V ≤ 115	1	N/A	Mandatory operation	
88 ≤ V ≤ 110	infinite	N/A	Continuous operation	
70 ≤ V < 88	$T_{VTR} = 0.7s + \frac{0.4s}{1p.u.}(V - 0.7\,p.u.)$	N/A	Mandatory operation	
50 ≤ V < 70	0.16	N/A	Mandatory operation	
V < 50	N/A	0.16	Cease to energize	

Frequency Ride Through Verification for All DERs		
Frequency Range (Hz)	**Minimum ride-through time (s) (design criteria)**	**Measure Response Time**
f > 62.0	0.16	
61.2 < f ≤ 62	299	
58.8 ≤ f ≤ 61.2	Infinite	
57.0 ≤ f < 58.8	299	
F < 57.0	0.16	

Synchronization Elements					
Parameter	As Left Setting	Nominal Settings			Test Passed
		0-500kVA	>500-1500kVA	>1500-25000kVA	
Frequency Difference (Hz)		0.3	0.2	0.1	
Voltage Difference (%)		10	5	3	
Phase Angle Difference (degrees)		20	15	10	

Anti-Islanding		
Anti-Islanding Detection Method (Active or Passive)		
Description of Anti-Islanding Method (e.g. Sandia Frequency Shift, ROCOF, Vector Shift, etc....)		
Test Type	**Nominal Setting**	**Test Result**
Loss of Utility Voltage (s)	2	
Generator Restart Delay after Utility Voltage Failure (minutes)	5	
Dead Bus Test (fail to start yes/no)	Yes	
Open Phase Detection (s)	2	

Functional Trips		
Test Type	**Nominal Time to Trip (s)**	**Measured Trip Time (s)**
DTT Signal Received	0.6	
DTT Communication Fail	2	
Breaker Fail	2	
Loss of Grounding Transformer	2	

Provided By:

Power Producer (Name / Company)

Title (P.Eng) Required

Signature

Professional Authentication: