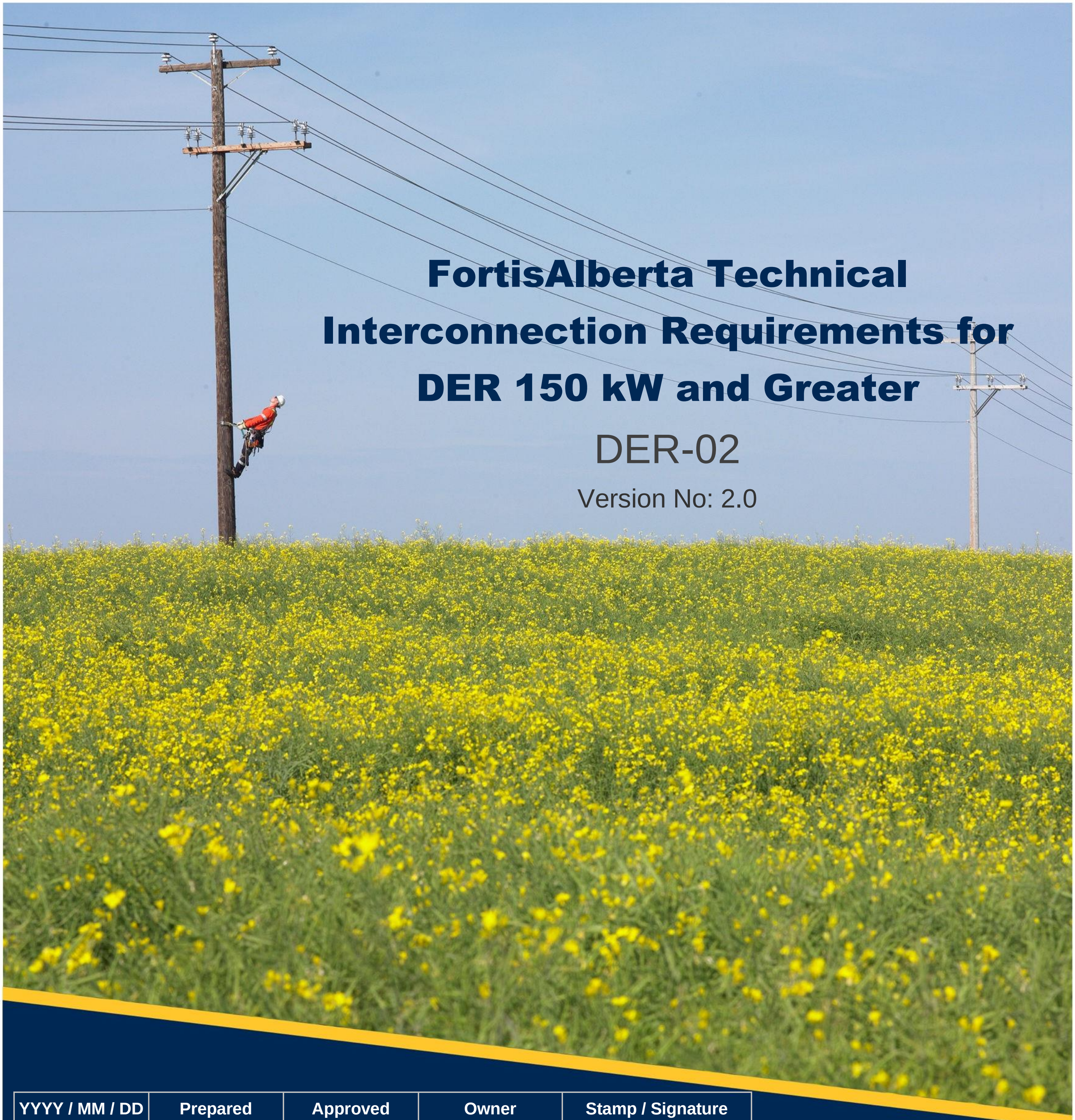

FortisAlberta Technical Interconnection Requirements for DER 150 kW and Greater

DER-02

Version No: 2.0

YYYY / MM / DD	Prepared	Approved	Owner	Stamp / Signature
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FORTIS ALBERTA

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This document is not a replacement for electrical codes or other applicable standards.

This document is not intended or provided as a design specification or as an instruction manual.

The DER owner, employees or agents recognize that they are, at all times, solely responsible for the generator plant design, construction and operation.

FortisAlberta Inc. (FAI), and any person employed on its behalf, makes no warranties or representations of any kind with respect to the DER requirements contained in this document, including, without limitation, its quality, accuracy, completeness or fitness for any particular purpose, and FAI will not be liable for any loss or damage arising from the use of this document, any conclusions a user derives from the information in this document or any reliance by the user on the information it contains. FAI reserves the right to amend any of the requirements at any time. Any person wishing to make a decision based on the content of this document should consult with FAI prior to making any such decision.

Revision History

Version	Date	Revision Details
2.0	August 2020	Alignment with CSA C22.3 No 9:20 Added Clarity on Engineering Studies Added Transmission Study Requirement Added Clarity on Anti-Islanding Requirements Added Clarity on Breaker Failure Protection Removed Requirement for PQ Monitor Updated DNP3 Points List Removed Annex A / B (Referred to CSA C22.3 No 9 and removed PQ Monitoring Requirement)
1.0	January 2019	New Standard Issued

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1. Scope

This document is prepared to assist DER owners understanding of their roles and responsibilities when connecting to the FortisAlberta electrical distribution system as a generator or aggregate of generation.

The requirements listed in this document apply to the following:

1.1. DER System greater than or equal to 150 kW

- Classification - Distributed Generation (DG)
  - Export
  - Non-Export
- Classification - Micro-Generation (MG)
- Classification - Energy Storage

1.1.1. Examples of such DER systems may include:

- Inverter-based Generation
- Synchronous Generation
- Induction Generation
- Battery Energy Storage System (BESS)

1.2. This document does NOT apply to the following:

- DER systems less than 150 kW [1]
- Generators (Momentary Closed Transition) [2] connecting momentarily (Parallel the distribution for 100 ms or less) through automatic transfer switches (such as back-up / standby generators).
- Generators which do not parallel with the distribution system. (Refer to the Canadian Electrical Code, Part I)

1.3. Technical Document Requirements

Technical documentation will be required through the interconnection process and may be required prior to energization[3].

1.4. Technical Standard Alignment

The technical requirements outlined in this document are in alignment with CSA C22.3 No. 9:20 - Interconnection of Distributed Energy Resources and Electricity Supply Systems.

CSA C22.3 No. 9:20 shall be the governing technical standard, unless otherwise specified in this document.

[1] For DER applications less than 150 kW, please review FortisAlberta Technical Interconnection Requirements for DER less than 150 kW FortisAlberta.com (Customer Service / Get Connected / Generation)

[2] For “Momentary Closed Transition” applications, please refer to the document “Interconnection Requirement Checklist - Standby or Backup Generator” FortisAlberta.com (Customer Service / Get Connected / Generation / Standby Generators)

[3] For “Technical Document Requirements”, please refer to the document DER Interconnection Document Requirements

2. Normative References

2.1. Familiarity, knowledge, and adherence to the following documents are prerequisites for the interconnection requirements cited in this document. There may be newer revisions of the following documents, in those cases the latest shall be applied.

2.2. Interconnection Standards

CSA C22.3 No. 9:20 – Interconnection of distributed resources and electricity supply system.

IEEE 1547-2018 – Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

C22.1 No. 1-2018 - Canadian Electrical Code (CEC), Part 1

Alberta Electrical Utility Code – 5th Edition

2.3. Equipment Standards

CSA C22.2 No. 107.1-16 – Power Conversion Equipment

IEEE 1547.1-2020 - IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces

UL 1741 (2018) – Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources

UL 1741 Supplement A – Test methods for advanced inverter functions

CSA C61000-4-30-10 (R2014) – Testing and measurement techniques – Power quality measurement methods.

2.4. Other Technical Standards

IEEE 519-2014 – Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

CSA C235-19 – Preferred Voltage Levels for AC Systems, 0 to 50 000 V

IEEE 2030-2011 – Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads

NISTIR 7628 (2010) – Guidelines for Smart Grid Cyber Security

CAN/CSA C71-1-99-1/2 – Insulation Coordination Guidelines

CAN/CSA-C61000-3-7 – Assessment of Emission Limits for the Connection of Fluctuating Installations to MV, HV and EHV Power Systems

2.5. FortisAlberta Interconnection Documentation

Interconnection Protection Settings and Commissioning (IPSC) – Settings proposal and commissioning documentation for all proposed protection relays within a DER system.

Maintenance Verification Form – Annual maintenance submission form

FortisAlberta Power Quality Specifications

Refer to the Get Connected or DER Documents Libraries online for all the latest FortisAlberta documents.

3. Glossary

anti-islanding: a protective functionality aimed at preventing the continued existence of an unintentional electrical island (see "Islanding" below) to avoid safety concerns and potential damage to customer equipment.

backup generator: an independent reserve source of electric energy that, upon failure or outage of the normal source, automatically provides reliable electric power within a specified time.

certified: tested and approved and by an accredited certification organization such as CSA, UL, IEEE

cease to energize: cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.

clearing time: the time between the start of an abnormal condition and the DER ceasing to energize the distribution system. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device. (used to interconnect the DER to the distribution system)

composite DER system: two or more individually compliant DER units which are connected in the same system. The overall system may need additional supplementary devices to ensure full compliance at the PCC

distributed energy resource (DER): a source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. DER includes DG and MG.

distributed energy resource (DER) system: the DER Unit's, interconnection systems, control systems, sensing devices or functions, and protection devices or functions up to the point of the DER connection.

distributed energy resource (DER) unit: an individual DER device inside a group of DER that collectively form a system.

distributed generation (DG): power generators that are connected to a distribution system through a Point of Common Coupling (PCC).

> **non-export:** a DER system which parallels with a distribution system for more than 100ms but does not export any generation to the distribution system.
>
> **export:** a DER system which parallels and exports all or a portion of its generation to the distribution system

distribution system: a system for distributing electricity, including any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system.

effectively grounded: distribution system or DER facility where the neutral conductor is grounded where:

$$\frac{X_0}{X_1} \leq 3, \qquad \frac{R_0}{X_1} < 1$$

where

X_0 = zero sequence reactance

X_1 = positive sequence reactance

R_0 = zero sequence resistance

electric power system (EPS): facilities that deliver electric power to a load.

emergency generator: an independent reserve source of electric energy that, upon failure or outage of the normal source, automatically provides reliable electric power within a specified time to critical devices and equipment whose failure to operate satisfactorily would jeopardize the health and safety of personnel or result in damage to property. These systems may be legally required for the safety of human life, or to protect against economic loss or concerns around the disruption of national security.

energize: active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient)

enter service: begin operation of the DER with an energized Area EPS

FAI: FortisAlberta Inc.

flicker: a perceptible change in electric light source intensity due to a fluctuation of input voltage. In the context of power supply disturbances, the term applies to perceptible, subjective, objectionable and random or periodic variations of the light output.

harmonics: sinusoidal voltages and currents at frequencies that are integral multiples of the fundamental power frequency which is 60 Hz in Alberta.

inverter: a machine, device, or system that changes direct-current power to alternating-current power

islanding: a condition in which a portion of a transmission and/or distribution system is energized solely by one or more DERs, while that portion is electrically separated from the rest of the transmission or distribution system.

micro generation (MG): a DER system which meets the requirements of the Alberta Energy Micro-Generation Regulation, Section 1(1)(h).

measurement point: the location where the interconnection performance requirements specified in this standard apply.

momentary closed transition: a DER which parallels to the distribution system for less than 100ms. See CSA C22.3 No 9-08 (7.4.13)

non-detection zone: the loading condition for which an islanding detection method would fail to operate in a timely manner, and it is represented in terms of the load parameters.

point of common coupling (PCC): the point of connection between the wires owner and the a DER facility.

point of connection (PoC): the point of connection to where a DER unit is connected to a DER system.

return to service: enter service following recovery from a trip.

ride-through: ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified

synchronization: the state and operation where the DER facility is connected to the distribution system and supplies loads along with the electric grid.

total harmonic distortion (THD): the ratio of the rms value of the sum of the squared individual harmonic amplitudes to the rms value of the fundamental frequency of a complex waveform.

wires owner: the entity who owns and/or operates a distribution system

4. Engineering Studies

DER facilities greater than or equal to 250kW will be required to perform the required studies in this section. These engineering studies are supplemental to ones performed by FortisAlberta and adhere to the requirements within this standard.

All studies completed by the DER owner and/or consultant shall be submitted and authenticated by a professional engineer who is registered with APEGA.

1) Short Circuit Analysis - Disturbance analysis studies which detail the following contribution and performance response of the DER system:
   - Fault detection and performance of the following fault conditions and locations:
     - LG / LLLG faults at the DER facility (PCC), any upstream protective device on the distribution system, and the substation 25kV and 138kV bus. (Further upstream protective zones may be required if determined by the transmission owner)

     Note: Generation output for the above studies shall include 25%, 50%, 75%, 100%, minimum generation output (DG owner to define)

   - Maximum Short Circuit Contribution – LG / LLLG faults at the DER facility PCC and at the substation 25kV bus.
2) Grounding Study – Provide a study which demonstrates the DER facility is effectively grounded and complies with the performance and power quality requirements in this document.
3) Self-Excitation Study (Induction Generation) – DER facilities with induction generators and where a transfer trip is not required shall conduct a study to demonstrate there will be no possibility of self-excitation.
4) Transmission Anti-Islanding Study (If Applicable) – A load to generation study may be required on the transmission system to determine if further protection is required.
   - Where the aggregate generation is under 33% of the minimum load of any concerning island scenarios (E.g. Feeder, transformer, transmission protection zones etc…) and passive / active anti-islanding is used, additional upgrade may not be required.

5. Interconnection Requirements

5.1. <u>Single Line Diagram (SLD)</u>

Minimum requirements include but are not limited to the following:

- Measurement Point (PCC / PoC) Location
- Disconnect Switch
- All Electrical Equipment (transformers, switches, generators, PT/CT's)
- Revenue Meter
- Protective Relays <u>ANSI Elements</u> (Clearly identifying protective relay functions)
- Authentication by a Professional Engineer (P.Eng)

<u>Note</u>: See Annex A, CSA C22.3 No 9:20 for example SLD's, including variations for different transformer winding configurations and measurement point requirements.

5.2. Measurement Point

The measurement point is the location where the DER system measures power system quantities for the purpose of implementing the protection and control functions required by this standard.

5.2.1. DER System 150 kW – 249 kW – Measurement point may be between the point of common coupling (PCC) and the point of connection (PoC). Where zero sequence continuity can't be maintained between the PoC and PCC the measurement point shall be located at the PCC.[1]

5.2.2. DER System 250 kW and Over – Measurement point must be at the point of common coupling (PCC)

Note: The minimum load of any local facility may be used to determine the measurement point location, where the local loads may offset the DER system contribution to the distribution system.

5.3. Insulation Coordination

The DER facility shall be protected from lightning, switching surges and temporary overvoltage (TOV). See CAN/CSA C71-1-99-1 and CAN/CSA C71-1-99-2 for insulation coordination guidelines.

5.4. Equipment Ratings

The DER system equipment standards shall align with FortisAlberta's equipment standards and shall not result in equipment on the distribution system to exceed its equipment ratings. This includes but not limited to the following:

- Maximum Voltage
- Basic Impulse Limit
- Short Circuit Ratings / Limits
  - DER system shall not increase FortisAlberta's short circuit levels beyond 5 kA single phase or 8 kA three phase at the upstream 25kV substation bus or at the PCC.
- Thermal loading limits

5.5. Isolating Device

DER systems shall follow the Canadian Electrical Code Part I and be capable of isolating from the distribution during maintenance and emergency conditions. Section 84 of CEC, Part I provides information to enable determination of the appropriate disconnect / isolation means for DER facilities.

5.6. Transformer Configuration

A wye/wye transformer winding configuration is preferred for DER interconnections, but other configuration types may be accommodated. Where there is a break in zero sequence continuity[1], additional equipment may be required to mitigate negative impacts to specific types of delta configurations. Refer to CSA C22.3 No 9:20 (Annex C) for more details.

[1] IEEE 1547-2018 - p28 – When the zero-sequence continuity is broken, for example by a delta-wye transformer between the PCC and the PoC, the voltages at the PoC may not be representative of the voltages at the PCC under abnormal voltage conditions. Examples of issues created by this condition include the following:

- Difficulty of 'sensing' single-phase-to-ground faults or failure to detect ground-fault over-voltages.
- Detecting abnormal voltage conditions when a DER back-feeds into the grid during a balanced open-phase condition.
- Ability of detecting a distribution system open-phase by the DER is diminished.

Note: The following interconnection concerns are associated with delta (primary) / wye configurations:

- Damaging overvoltage (Single phase faults / Open phase conditions);
- DER facility cannot detect single phase faults with normal overcurrent protection; and
- High voltage concerns due to ferro-resonance

5.7. Interconnection Grounding

In accordance with CSA C22.3 No. 9:20, DER Systems must be grounded as per manufacturer's recommendations and CEC Part I. Transformer grounding systems shall be coordinated with FortisAlberta and shall not cause voltage disturbances or disrupt coordination of distribution system ground fault protection.

The DER facility shall be effectively grounded as defined in this document.

5.8. DER Unit Certification

For all individual inverter systems and multiple inverter systems:

- CSA C22.2 107.1 and UL 1741/SA certifications are required prior to energization.
- Only inverters which are certified may be connected to the distribution system.

5.9. Measurement Accuracy

DER facility shall meet the accuracy requirements from CSA C22.3 No. 9:20 (Section, 7.1.3).

5.10. Voltage/Power Control Requirements

DER facility shall meet the requirements of CSA C22.3 No. 9:20 (7.2.3 Voltage Regulation and Power factor)

The DER system shall be operating at an agreed power factor at the PCC, but also be capable of the modes of operation listed in CSA C22.3 No. 9:20 (Section 7.2.3).

DER Units may use different voltage control modes to manage voltage within the DER facility, but the DER system shall maintain constant power factor at the PCC, unless otherwise specified by FortisAlberta.

The DER operator shall be responsible for implementing setting modifications and mode selections, as specified by FortisAlberta and within a time acceptable to the FortisAlberta. Under agreement between the FortisAlberta and the DER operator, control modes and implementations other than the ones listed above may be permitted.

5.11. Reactive Power Requirements

DER facility shall meet the Reactive Power Requirements detailed in CSA C22.3 No. 9:20 (Section 7.2.3.2)

5.12. Cease to Energize Performance Requirement

DER facility shall meet the Cease to Energize requirements of CSA C22.3 No. 9:20 (Section 7.4.7.7)

If requested by FortisAlberta, the DER system shall provide reactive susceptance (sourcing and/or consumption) that remains connected to the distribution system in cease to energize state.

6. Power Quality Technical Requirements

This section outlines the technical requirements for the DER system's owner to maintain satisfactory power quality at the PCC.

I. If undesirable power quality on the FortisAlberta distribution system is being caused by the DER system not adhering to the requirements within this section, the DER owner will be required to cease the operation of the offending equipment. Disconnection may be required until satisfactory corrective action has been taken by the customer as per the "Customer Terms and Conditions of Electric Distribution Service" document Article 12.
II. FortisAlberta will enforce all disconnections as per section 5.2.4 & 10.3.2 of the "FortisAlberta Inc. Customer Terms and Conditions of Distribution Access Service" document.

6.1. Voltage

Upon approval by FortisAlberta of control modes other than constant power factor mode, the DER owner is responsible to manage the voltage/power control modes of the DER system to ensure compliance to the range specified in the "FortisAlberta Power Quality Specifications" document

6.1.1. Limitation of overvoltage contribution

The DER facility shall not cause the fundamental frequency voltage, line-to-ground or line to line, on any portion of the distribution system to exceed 138% of its nominal fundamental frequency voltage for a duration exceeding one fundamental frequency period.

6.1.2. Ramp Rate

During normal operation, active power output shall increase linearly on the DER system and shall not exceed the following rate of change:

- The nameplate active power rating divided by the enter service period of 300 seconds, with a maximum step increase not exceeding 20% of the DER nameplate active power rating. (i.e. A linear increase in active power over 5 minutes, where a step increase shall not exceed a 20% increase)

6.2. Voltage and Current Unbalance

The DER facility shall be capable of operating under existing utility distribution system voltage and current unbalance conditions and protect itself from the unbalance.

The DER facility shall not increase existing voltage unbalance levels at the PCC and in the distribution system.

The DER facility shall comply with the voltage unbalance limits set out in the "FortisAlberta Power Quality Specification" document as amended from time to time.

6.3. Flicker and Rapid Voltage Change (RVC)

The DER system shall not introduce voltage fluctuations beyond the limits specified in the "FortisAlberta Power Quality Specifications" document. For details on how to perform flicker emission level evaluation, refer to CAN/CSA-C61000-3-7 “Limits - Assessment of Emission Limits for the Connection of Fluctuating Installations to MV, HV and EHV Power Systems”.

6.3.1. Customer Flicker Emission Limits

For each DER system, only a fraction of the global emission limit shall be allowed. The calculation for individual emission limits shall be determined with reference to the “FortisAlberta Power Quality Specifications” document

6.3.2. Rapid Voltage Changes (RVC)

The RVC Limits as set out in the “FortisAlberta Power Quality Specifications” document shall not be exceeded at the PCC.

6.4. Harmonic Distortion

Current harmonics limits, inter-harmonic limits, DC injection limits, and telephone interference limits as specified in the “FortisAlberta Power Quality Specifications” document shall be met by the DER system.

6.5. Telephone Interference

The DER customer’s facility at the PCC shall not have calculated or measured I-T product values exceed the limits as set out in the “FortisAlberta Power Quality Specifications” document.

7. Response to Abnormal Conditions Requirements

All requirements specified in this section shall be met at the measurement point unless otherwise specified.

7.1. Shall Trip Requirements

All **DER Units** shall comply with the default shall trip requirements for Supplemental Grade as detailed in Table 9 and Table 11 of CSA C22.3 No. 9:20.

All **DER Systems** shall comply with the following trip requirements, where the measurement point is at the PCC.

Table 9 – Voltage Trip Requirements @ PCC

Trip Function	Voltage (% of nominal voltage)	Clearing Time (s)
OV3	120	0.16
OV2	110	0.5
OV1	106	45
[redacted]		
UV1	88	2.0
UV2	45	0.16

Table 10 – Frequency Trip Requirements @ PCC

Trip Function	Frequency (Hz)	Clearing time (s)
OF2	62.0	0.16
OF1	61.2	300.0
[redacted]		
UF1	58.5	300.0
UF2	56.5	0.16

7.2. Anti-Islanding

7.2.1. All types of generation shall cease to energize and trip within 2 seconds of the formation of an island.

7.2.2. DER facilities shall meet the anti-islanding requirements listed below in Table 11.

7.2.3. Required anti-islanding studies shall be submitted to FAI for review. Based off the review FAI may require a transfer trip. Failure to provide the required studies will initiate a mandatory direct transfer trip requirement.

Table 11 – DG Facility Anti-Islanding Requirements

Generation Type	Aggregate Capacity	Direct Transfer Trip (DTT)	Anti-Islanding Method
Synchronous	≤ 1 MW	FAI to Review	Passive[1]
	> 1 MW	Required	DTT
Inverter-Based	All	Not Required[4]	Active[2]
Induction	≤ 1 MW	Not Required	Passive[1]
	> 1 MW	Required	DTT[3]

[1]Anti-Islanding method must be reviewed and accepted by FAI. Direct transfer trip may be required upon review.
[2]Inverter-based generation shall meet the anti-islanding requirements of CSA C22.2 No. 107.1 and UL 1741 SA
[3]A Self-Excitation study may be accepted to remove a DTT requirement.
[4]In some cases, non-reclose on live line and sync checks may be used on the distribution system to mitigate islanding concerns.

7.2.4. Passive Anti-Islanding

Passive anti-islanding schemes shall use at the minimum the following elements:

a) Rate Of Change Of Frequency (ROCOF); and

b) Vector Shift or Reverse Reactive Power

The DER passive anti-islanding scheme (including protection set points) must be submitted to FAI for review and approval. If the scheme is not approved by FAI, a direct transfer trip will be required.

DER facilities containing passive anti-islanding schemes shall have provision for the capability to receive a transfer trip signal and cease generation. The actual implementation may not be required at time of DER energization and may be requested later at the DER owners' cost. The request would be initiated upon the emergence of a non-detection zone (i.e the load to generation ratio is insufficient to provide an incremental change to frequency, power or vector shift that can be detected by the passive anti-islanding scheme).

7.2.5. Active Anti-Islanding

Method for active anti-islanding shall be provided to FortisAlberta for review. E.g. Sandia Frequency Shift (SFS), Active Frequency Drift (AFD), or other.

7.2.6. Direct Transfer Trip

A direct transfer trip signal from the upstream protection devices (Breaker, MVI, Reclosers) will be required based on the following criteria:

a) Requirements identified in Table 11; **or**

b) Aggregate DER Facility capacity if greater than 33% of the minimum load downstream of recloser(s); (Not Inverter-Based) **or**

c) Results from a transmission anti-islanding / protection study which identify DTT as a requirement for transmission protection **or**

d) The emergence of a non-detection zone.

It is the responsibility of the DER owner to design and implement a DTT scheme. FAI will provide a DTT signal from all upstream protection devices (Reclosers, MVIs). The design shall include:

a) DER site isolation from FAI's distribution system upon receiving a DTT signal.

b) Communication design and protocol between DER facility and upstream distribution protection devices. FAIs preferred protocol is *Mirrored Bits* (Schweitzer Relay Protocol).

c) The DTT signal must be failsafe. Upon loss of DTT signal the DER facility shall disconnect from the distribution system within 2 seconds. The DER shall remain disconnected until the DTT signal is restored.

d) Incorporate separate DTT signals from all FAI mainline protection equipment in series upstream from the DER facility. FAI to advise of the communication requirements for the DTT during detail level study.

Exception: Transmission DTT (if applicable) - Consultation with the transmission owner will be required to determine DTT communication requirements

The DTT scheme shall be submitted to FAI for approval prior to implementation.

7.3. Entering Service and Synchronization

DER facility shall meet the entering service and synchronization requirements from CSA C22.3 No. 9:20 (Section, 7.4.6.2)

7.3.1. Return to Service after Trip

After ceasing to energize the distribution system due to any abnormal condition, the DER system must wait 300 seconds before attempting to reconnect, unless otherwise specified by FortisAlberta.

7.4. Breaker Failure

7.4.1. DER facilities with an aggregate output > 1 MW shall provide breaker failure protection for the primary interrupting device that is responsible for disconnecting the generator and/or the HV ground sources from FortisAlberta's distribution system.

7.4.2. In the event of a breaker fail condition at the primary interrupting device the DER facility shall be capable of the following:

a) Full isolation of the DER facility upstream from the breaker failure condition. This may include trips to multiple upstream protection devices or isolation of the prime mover / excitations system as needed to fully isolate from FAIs distribution system.

b) Failsafe protection relay configuration if the protection relay fails to trip the isolation device. This may include redundant relays and/or failsafe contacts.

7.4.3. The breaker failure protection shall have a maximum pickup time delay of 0.3 seconds after initiation. Full isolation shall take less than 2 seconds after breaker failure detection.

7.4.4. DER facilities ≤ 500 kW shall have an alternate means of disconnecting the DER energy source from the distribution system when a breaker fail condition is triggered. This can be achieved by opening of the isolation device, disabling an inverter, or removing the prime mover and excitation system as needed.

7.4.5. All Breaker Failure schemes shall be submitted to FAI for approval prior to implementation.

7.5. Distribution System Faults

7.5.1. The DER protection shall detect and isolate the facility from the distribution system for phase-phase and phase-ground:

c) Internal faults within the DER facility **and**
d) External faults on the distribution system.

7.5.2. Fault protection shall be coordinated with the distribution upstream/downstream protection devices. For coordination, the FortisAlberta Interconnection Protection Settings and Commission (IPSC) document, Section 1, shall be completed and submitted to FortisAlberta for review.

7.6. Directional Protection

7.6.1. Non-Export DER systems shall have directional protection through utilization of a 67/67N/32R capable protective relay.

7.6.2. Directional protection may also be required on the distribution system to prevent mis-operation due to sympathetic tripping. This may be located at a substation breaker or an upstream recloser. FAI will assess this requirement during the detailed level study.

7.7. Open Phase Protection

The DER system must be capable of detecting of any open phase condition on the distribution system and must cease to energize and trip all phases to which the DER is connected within 2 seconds.

7.8. Reclose Coordination

The DER system shall coordinate with FortisAlberta's protective devices to ensure distribution customers are not exposed to disturbances due to out-of-phase reclosing, or mis-coordinated tripping.

8. Monitoring & Control Requirements

8.1. Provisions for real-time operating are required at DER facilities connected to FortisAlberta's distribution system.

8.2. Monitoring Data Requirements

Real-time data to be provided to FortisAlberta by the DER owner is dependent on the output rating of the DER Facility as listed below:

8.2.1. Class 1 - Total DER System Generation < 500 kW

DER facilities shall have the provision for monitoring the disconnecting device at the PCC/PoC. (Refer to Annex A for data point requirements)

I. SCADA connection is not required unless otherwise specified by FortisAlberta.

Provisions for other data points may be required if determined by FortisAlberta.

8.2.2. Class 2 - Total DER System Generation ≥ 500 kW

A SCADA connection to FortisAlberta's shall be required.

All communication and parameter mapping requirements outlined in Annex A shall be met.

Provisions for additional data points may be required if determined by FortisAlberta.

Other: AESO Communication is required for DER facilities that are 5MW or larger.

8.3. Control Requirements

Subject to the agreement between the DER Owner and FortisAlberta, the following controls shall be provided to FortisAlberta:

a. Main interconnection breaker;

b. Dynamic generator output control; (Refer to CSA C22.3 No 9:20, Table D.1)

9. Commissioning Requirements

9.1. The DER Owner is fully responsible for the inspection, testing, and calibration of its equipment, at the PCC.

9.2. FortisAlberta may witness any part of the commissioning testing at the PCC, request additional testing and conduct their own testing.

9.2.1. The DER owner shall advise FortisAlberta 30 days in advance of scheduled commissioning activities and include a signed copy of section 1 of the FortisAlberta IPSC document.

9.2.2. The DER owner shall provide the results of an Data Concentrator (RTU) bench test, one week prior to the scheduled commissioning. The RTU bench test shall include, but not limited to, the following:

a. Point-to-point testing, verifying signals from field devices back to the RTU. This testing cannot be simulated, all signals must be verified to the point of origin in real-time.

b. A report shall be submitted to FortisAlberta, validating that the signals have been verified and the RTU signal mapping complies to the mapping presented in *Annex A.* The report shall also contain a copy of the configuration parameters of the RTU.

9.2.3. Section 2 of the IPSC document must be signed and submitted to FortisAlberta prior to the interconnection energization of the facility.

9.3. A Power Quality report confirming an initial benchmark and one month review of the DER facility post energization shall be provided to FortisAlberta to ensure compliance with all PQ requirements.

9.4. <u>Interconnection equipment testing shall include, but is not limited to, the following</u>:

a. Power Transformer tests (when owned by DER customer)
b. Instrument transformer tests (insulation, ratio/polarity, excitation and resistance results);
c. Breaker timing trip tests for those breakers used to disconnect the DER from FAIs distribution system;
d. Functional tests confirming the protection and control logic and timer settings;
e. Verification of test trips and alarm processing;
f. Verification of control interlocks in protections;
g. Verification of synchronizing system and synch-check controls; not applicable if DER is inverter based;
h. Voltage phasing checks (prior to first connection);
i. Verification of Transfer Trips and end to end checks. This will require participation and coordination with FortisAlberta;
j. Verification of all analog and equipment status points from the IEDs which are monitored and controlled by FortisAlberta's Control Center. This will require participation and coordination with FortisAlberta.

9.5. Any deficiencies in the above testing found during commissioning must be corrected by the DER owner prior to the DER interconnection approval by FortisAlberta and/or any generation output of the DER facility.

9.6. All commissioning test results, supportive of Section 2, of the FortisAlberta Interconnection Protection Settings and Commissioning document (IPSC) or other, shall be recorded and made available to FortisAlberta upon request.

10. Maintenance Requirements

10.1. The DER Owner is responsible for all equipment maintenance within their facility. FortisAlberta requires the DER owner to perform annual maintenance of the equipment at the PCC. FortisAlberta's *Maintenance Verification Report* must be filled out and signed off **annually** by a qualified worker.

10.2. Maintenance at the PCC shall include, but not limited to, the following equipment:

a. Protection and control systems (Including protective relays, transfer trips and control interlocks)
b. Power meter (when applicable)
c. Power transformer (if owned by the DG)
d. Instrumentation transformer (Current and voltage transformers)
e. Isolation device (Breakers and disconnect switches)

10.3. Inspection and testing for annual maintenance shall follow the schedule below:

Table 13 – Inspections and Tests

Inspection and Test	Frequency of Test
Visual	A visual inspection shall take place on an annual basis.
Visual / Mechanical	A visual inspection including mechanical operation shall take place every 3 years.
Visual / Mechanical / Electrical	A visual inspection including mechanical and electrical operation shall take place every 5 years.
Exceptions	When transfer trips are required, they must be verified on an **annual** basis.
Special Circumstances	If a power system event (transient over-voltage, fault, etc.) causes damage to equipment at the point of interconnection ALL equipment must undergo full visual / mechanical / electrical inspections and tests to ensure the integrity of the surrounding equipment.

Review FortisAlberta's *Maintenance Verification Report* for all definitions of the above inspections and test.

Annex A (Normative)

SCADA Requirements & DNP3 Parameter Mapping

A1. Interoperability Requirements

Provisions shall be made by the DER for a local communication interface with FortisAlberta's network that will support the information exchange requirements specified in this annex. The provisions shall include a FortisAlberta network communication module. The module will allow FortisAlberta to monitor, control and exchange information as needed.

The DER is responsible for the communication module equipment costs and the labour involved in installing and commissioning the device. FortisAlberta will own, operate, maintain, and supply the junction box

A1.1. Fortis Alberta Communication Module Requirements **(module supplied by FortisAlberta)**

Table C1 – FA Communication Module Requirements

Requirements	
Module Interconnection	Refer to the Communication Interconnection diagram (Section A4) below for details.
Preferred Location	FortisAlberta's preferred location is wall mounted on the exterior of the control cabinet or building containing the intertie relay
Accessibility	FortisAlberta requires full access to the module on a 24Hr. / 7D per week basis
Connection Points	The module shall be connected directly to the DER facility's data concentrator (RTU).
Cables	DER facility shall provide the communication cable (RS232 DB9) from the facility RTU to the FortisAlberta external communication enclosure. DER facility shall provide 2C #14 copper 600V w/ ground conductor from the facility RTU to the FortisAlberta external communication enclosure.
Supply Power	120 VAC or 13-20 VDC

A1.2. Communication Protocol Requirements

The DER customer shall be capable of supporting FortisAlberta's communication protocol at the local DER communication interface. The following protocol shall be supported:

Table C2 – Communication Protocol Requirements

Protocol	Transport	Physical Layer
IEEE Std. 1815 (DNP3)	None	Serial Baud Rate: 9600 Data Format: 8N1 Flow Control: CTS Framing

Protocols and physical layers within the DER facility can differ from the local DER communication interface.

A1.3. Communication Performance

The local DER communication interface shall always be active and responsive when in operation. The maximum allowable response time to read requests is 60 seconds.

A2. Monitoring and Control

All monitoring and control information shall be available through the local DER communication interface.

The DNP mapping below is required by FortisAlberta.

Monitoring requires read-only access to the intertie relay and power meter (if meter is required). Any configuration and setting changes are to be managed by the DER owner.

FortisAlberta requires the ability to open and close the main DER isolating device remotely under emergency conditions or when the DER facility is deemed as the cause for any voltage instability on FortisAlberta's power system.

A2.1. Additional Requirements

In addition to the minimum signals identified in the DNP map below, FortisAlberta requires direct access to intertie relay event logs, trip logs and disturbance waveform captures.

All time stamps shall be Coordinated Universal Time (UTC).

A3. DNP3 MAPPING

Table C3 – DNP3 Mapping

DNP3 Index #	Signal Type (Analog/Binary)	Signal	State 1 "0"	State 2 "1"	Class	Variation	Scaling (Decimal Point)
000	Binary Input	Trip / Fault Indication	NORMAL	TRIP	1	2	
001	Binary Input	52A - Breaker Status (Open/Closed)	OPEN	CLOSE	1	2	
002	Binary Input	Phase A Fault	NORMAL	FAULT	1	2	
003	Binary Input	Phase B Fault	NORMAL	FAULT	1	2	
004	Binary Input	Phase C Fault	NORMAL	FAULT	1	2	
005	Binary Input	Ground Fault	NORMAL	FAULT	1	2	
006	Binary Input	*Close Block – (Enabled by FortisAlberta ONLY)* *(When enabled breaker will not close onto the distribution system. May be used for operational purposes)*	NORMAL	CLOSE BLOCK	1	2	
007	Binary Input	Aux. Battery Healthy (if applicable)	FAIL	NORMAL	1	2	
008	Binary Input	RTU Relay Healthy	FAIL	NORMAL	1	2	
009	Binary Input	*Reverse Fault Detection (Looking towards the distribution system)*	NORMAL	FAULT	1	2	
010	Binary Input	*Supervisory Control (Recloser can only be operated remotely when in remote)*	LOCAL	REMOTE	1	2	
011 to 099	*Binary Input*	*Reserved Binary Inputs for future use*					

100	Binary Input	Generator 1 - Status (On/Off)	OFF	ON	1	2	
101-199	*Binary Input*	*Reserved Binary Inputs for future use*					
200	Binary Input	Generator 2 - Status (On/Off)	OFF	ON	1	2	
201-299	*Binary Input*	*Reserved Binary Inputs for future use*					
300	Binary Input	Generator 3 - Status (On/Off)	OFF	ON	1	2	
301-399	*Binary Input*	*Reserved Binary Inputs for future use*					
400+	*Binary Input*	*Binary Inputs for additional generators*					
000	Analog Input	Current Magnitude A – (Amps)			2	3	1
001	Analog Input	Current Magnitude B – (Amps)			2	3	1
002	Analog Input	Current Magnitude C – (Amps)			2	3	1
003	Analog Input	Current Magnitude N – (Amps)			2	3	1
004	Analog Input	Distribution - Voltage Magnitude A – (kV)			2	3	2
005	Analog Input	Distribution - Voltage Magnitude B - (kV)			2	3	2
006	Analog Input	Distribution - Voltage Magnitude C - (kV)			2	3	2
007	Analog Input	DER System - Voltage Magnitude A - (kV)			2	3	2
008	Analog Input	DER System - Voltage Magnitude B - (kV)			2	3	2
009	Analog Input	DER System - Voltage Magnitude C - (kV)			2	3	2
010	Analog Input	Active Power three-phase (MW)			2	3	3
011	Analog Input	Reactive Power three-phase (MVAR)			2	3	3
012	Analog Input	Power three-phase (MVA)			2	3	3
013	Analog Input	Frequency (Hz)			2	3	2
014	Analog Input	Power Factor (%)			2	3	2
015	Analog Input	Fault Current A (Amps)			2	3	1
016	Analog Input	Fault Current B (Amps)			2	3	1
017	Analog Input	Fault Current C (Amps)			2	3	1
018	Analog Input	Fault Current G (Amps)			2	3	1
Voltage Control Modes		Constant Power Factor Mode = 0 Active Power-Reactive Power Mode = 2 Voltage-Active Power Mode = 4		Voltage-Reactive Power Mode = 1, Constant Reactive Power Mode = 3,			
90	Analog Input	Facility Master Controller - Control Mode *(Where the DER facility has a central controller, which controls the voltage control mode at the PCC)*			2	3	
91	Analog Input	*Enter Service Delay (s) 1 - 600 (default 300)* *(DER facility must delay a specific time before connecting to the distribution system which has just recently energized)*			2	3	
100	Analog Input	Generator 1 - Control Mode			2	3	
101	Analog Input	Generator 1 – Active Power Output (MVA)			2	3	3
102	Analog Input	Generator 1 – Reactive Power Output (MVAR)			2	3	3
103 to 199	*Analog Input*	*Reserved Analog Inputs for future use*					

200	Analog Input	Generation 2 - Control Mode			2	3	
201	Analog Input	Generation 2 – Active Power Output (MVA)			2	3	3
202	Analog Input	Generation 2 – Reactive Power Output (MVAR)			2	3	3
203 to 299	*Analog Input*	*Reserved Analog Inputs for future use*					
300	Analog Input	Generation 3 - Control Mode			2	3	
301	Analog Input	Generation 3 – Active Power Output (MVA)			2	3	3
302	Analog Input	Generation 3 – Reactive Power Output (MVAR)			2	3	3
303 to 399	*Analog Input*	*Reserved Analog Inputs for future use*			2	3	*3*
400+	*Analog Inputs*	*Analog Inputs for additional generators*					
000	Binary Output	*52A – Main Breaker Open*					
001	Binary Output	*52A – Main Breaker Closed*					
002	Binary Output	*FortisAlberta – Close Block* *(When enabled breaker will not close onto the distribution system. May be used for operational purposes)*					
90	Analog Output	Facility Master Controller - Control Mode *(Where the DER facility has a central controller, which controls the voltage control mode at the PCC)*					
91	Analog Output	*Enter Service Delay (s) 1 - 600 (default 300)*					
100	Analog Output	*Generator 1 - Mode Selection*					
101-199	*Analog Output*	*Reserved Analog Outputs for future use*					
200	Analog Output	*Reserved for Generator 2 - Mode Selection*					
201-299	*Analog Output*	*Reserved Analog Outputs for future use*					
300	Analog Output	*Reserved for Generator 3 - Mode Selection*					
301-399	*Analog Output*	*Reserved Analog Outputs for future use*					
400+	*Analog Output*	*Reserved Analog Outputs for additional generators*					

A4. Communication Interconnection Diagram