FortisAlberta Technical Interconnection Requirements for All Three Phase DER and Single-Phase DER 150 kW and Greater

DER-02

Version No: 6.1

2025 / 04 / 16	2025 / 04 /16			
Prepared	**Approved**	**Owner**	**Authentication**	**Validation**
Keaton Wheeler Principal Engineer Advanced Power Systems	Michael Simone Manager Operations Engineering	Operational Engineering Services	PROFESSIONAL ENGINEER KEATON A. WHEELER ALBERTA Authenticated original filed with the Engineering Department	**APEGA PERMIT NUMBER: P07387** Responsible Member (RM) to sign and date authenticated original file RM Name: Michael Simone RM Signature: Date:
Additional Reviewers and/or Contributors	Shane Harbourne, P&C Engineer Peter Zhou, Sr. Lead Engineer Power Quality Michael Roles, SCADA Engineer			

LIMITATION OF LIABILITY AND DISCLAIMER

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
6.0	January 2025/ (6.1) April 2025	Alignment to IEEE 1547-2018. References to CSA C22.3 No.9 have been transitioned out. Three-phase DERs under 150kW added to standard. Process related clauses removed and moved to a different document. Added clarity to infrequent RVC requirements. Multiple references to kW changed to kVA (e.g. 500 kW requirements are now 500 kVA requirements). Updates to anti-islanding requirements and screening. DER certification requirements updated to include ICAP for all sites greater than or equal to a nameplate rating of 500 kVA and all uncertified sites. (6.1) PCC measurement requirement changed to 500 kVA instead of 250 kVA. (6.1) ICAP requirement changed to DER systems where the measurement point is the PCC. (6.1) FortisAlberta SCADA requirements adjusted to match with measurement point. (6.1) Clarity added to 5.11 for communications loss from power plant controllers to DER units. (6.1) Clause 5.15 added to give clarity of aggregation of multiple DER units. (6.1) 5.17.2 changed to align with measurement point. (6.1) Clause 6.7 added for clarity around real and reactive power fluctuations during steady state operation.
5.0	December 2023/ (5.1) February 2024	DNP map points added, removed, and updated. Annex B updated to include IPSC Section 3. Change to inverter unit certification being UL1741 SB or better. Clarity added to RVC requirements. Additions to harmonic distortion requirements. Changes to PQ reporting. Changes to energization package. Changes to commissioning requirements. Clarified power factor set points and FortisAlberta support in voltage requirements. Microgeneration intertie breaker requirements added. Updated DER isolating requirements. Added ICAP process requirements. DER Unit certifications sections split up with additions for wind and machine-based generation. Updated guidance on use of LEAs in the measurement accuracy clause. Updated overhead interconnection requirements for GFO facilities to include bird proofing. Updating requirements for isolating devices and separating loads from

		generation. Added requirements for lockout and tag procedures in commissioning. Added notice period for commissioning schedule changes. Added guidance on energizing as a load. Added requirement for IPSC Section 2 results being tested before FortisAlberta staff will be available to come to site. Changes to Energization Package Requirements. Clarification on close block requirements added. Data Concentrator file to be provided to FortisAlberta. (5.1) Minor adjustments to second PQ report in Section 6.6. (5.1) Clarification added to Section 7.2 on trip timings not be allowed to change with system frequency. (5.2) Directional overcurrent element requirements adjusted in Sections 7.1.2, 7.8.12, and 7.9.2.2. (5.2) Removed requirement to provide .exp and .par file from Section 8.2. (5.3) Section 7.1 directional requirements adjusted for clarity. (5.3) Section 7.8 directional requirements adjusted for clarity. (5.3) Section 7.9 directional requirements adjusted for clarity.
4.0	November 2022/ (4.1) January 2023/ (4.2) March 2023	Typical islanding detection methods added. Non-export mode requirements added. Added mirrored bits protocol required for a DTT. Microgeneration export limiter requirements added. Added clarity to RVC, Harmonic Distortion and power quality monitoring requirements for benchmark reporting. IPSC Section 2 review procedure added. Clarified that the DER equipment must be isolated when commissioning the PCC relay. Added requirements for sites that are rated higher than their export limit. Added requirements around equipment delivery schedules. Added clarification on machine-based DER certifications. Added clarification on AESO versus FAI anti-islanding. (4.1) Minor update to Power Quality monitor requirements (January 2023) (4.2) Clarification given in Section 7.4.8 DTT requirements (March 2023). (4.2) Clarification that MW are the required parameters in Annex C. (4.2) Addition/clarification that a transformer inrush study is required. (4.2) Clarification to GIS requirements added. (4.2) Clarification to DNP3 point mapping. (4.2) Clarification to commissioning.
3.0	October 2021	Updated Shall Trip Requirements for Voltage. Added Ride Through Requirements. Added a Guide for Engineering Study Requirements (DER-02A). Added Commissioning Document Package Requirements. Revised Commissioning Requirements. General Clarity Improvements.

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.

Table of Contents

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. Three- phase DER Systems and Single-Phase DER Systems 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:

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

1.2. This document does NOT apply to the following:

- Single-phase 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)
- Grid-forming Inverter-based Generation: For DERs that are Grid-Forming Inverter-based generation, a separate application shall be made to FortisAlberta.

1.3. Technical Document Requirements

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

1.4. Technical Standard Alignment

The technical requirements outlined in this document are in alignment with IEEE Standard 1547-2018: IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces and Alberta 1547-2018: IEEE 1547-2018 standard adjustments for the Province of Alberta, Canada.

IEEE Standard 1547-2018 shall be the governing technical standard with adjustments as per Alberta 1547-2018, unless otherwise specified in this document.

[1] For single-phase 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)

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

Alberta 1547-2018: IEEE 1547-2018 standard adjustments for the Province of Alberta, Canada

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

Alberta Electrical Utility Code – 5th Edition

2.3. Equipment Standards

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 B – Test methods for advanced inverter functions

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

UL2200/ULC2200 – Stationary Engine Generator Assemblies

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

CSA C22.2 NO 14 - Industrial control equipment

CSA C22.2 NO. 100-14 (R2019) - Motors and generators

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.

dead band: a value by which a change in an analog point greater than its dead band will trigger a point update. Based on the raw value of an analog point and in engineering units.

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:

Machine-Based Generation

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

where

X_0 = zero sequence reactance

X_1 = positive sequence reactance

R_0 = zero sequence resistance

Inverter-Based Generation

$$0.01 \leq \frac{X_0}{R_0} \leq 0.3, \qquad 1 \leq \frac{Z_0}{Z_{1Load}} \leq 2$$

Z_0 (R_0+jX_0) is the impedance of the supplemental grounding

Z_{1load} is the equivalent impedance of the grounded load of the network.

Source: EPRI (Effective Grounding for Inverter-Connected DER, Public Report 3002020130)

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)

energization date: date at which the DER facility may start critical load facilities and testing procedures.

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

in-service date: date at which the DER facility may start to generate onto the distribution system, not to be confused with the energization.

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: the momentary interconnection (less than or equal to 100 ms) of a DER system to the distribution system with the purpose of transferring load from the distribution system to the DER and then operating in stand-alone (emergency) mode or transferring load from the DER back to the distribution system.

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/point of interconnection (PCC/POI): 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.

witness testing: the final stage of commissioning in which FortisAlberta's Field Technical Services and SCADA department test the functionality of the site's main breaker. To be done as part of the last steps of the final commissioning package, just prior to site energization.

4. Engineering Studies

Engineering studies are supplemental to ones performed by FortisAlberta and must adhere to the study requirements in the DER-02A – FortisAlberta Engineering Study Guide for DER Interconnections document. All studies completed by the DER owner and/or consultant shall be submitted and authenticated by a professional engineer who is registered with APEGA.

5. Interconnection Requirements

5.1. Single Line Diagram (SLD)

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, arresters)
    - Includes transformer configuration and any supplemental grounding devices.
- Revenue Meter
- Protective Relays ANSI Elements (Clearly identifying protective relay functions)
- Breaker Failure clearly identified if applicable, see section 7.6.
- Authentication by a Professional Engineer (P.Eng.)

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

An authenticated SLD is required for the at the following stages of the project:

- Detailed Level Study
- 110 Day Package - Issued for Construction (IFC) SLD

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. Three-phase DER Systems with a nameplate rating less than 500 kVA and Single-Phase DER Systems with a nameplate rating of 167kVA (150 kW at 0.9 power factor) – 500 kVA – Unless otherwise specified by FortisAlberta, the measurement point may be between the point of common coupling (PCC) and the point of connection (PoC). Where zero sequence continuity cannot be maintained between the PoC and PCC the measurement point shall be located at the PCC.[1]

5.2.2. DER Systems with a nameplate rating of 500 kVA and Over – The measurement point shall be at the point of common coupling (PCC)

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.

[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.

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 system 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.

5.5.1. For all DER sites using built in inverter protection without a separate protection device, when an abnormal condition is detected by the inverter protection, a transfer trip signal shall be sent to DER isolating device to physically isolate the DER from the distribution system. This is not applicable to sites less than 150 kW.

5.5.2. All DER sites with overhead connections shall have a gang-operated, visible disconnect switch where the electrical contacts of the switch are required to be visible. Flags, or visual indicators shall not be considered sufficient for this purpose. This is not applicable to sites less than 150 kW.

5.5.3. DER facilities shall be designed to disconnect loads separately from the aggregated generation. The generation disconnect shall be equipped with sufficient means for a FortisAlberta Inc. representative to lock out and tag out the aggregated generation. The lock out shall not be directly connected to the bus work, circuit breaker high voltage parts, or within an energized electrical cabinet or switchgear. This is not applicable to sites less than 150 kW.

5.5.4. The physical location of the isolating device should (not mandatory) be in a location that is accessible to FortisAlberta staff. If the isolating device is not easily to accessible to FortisAlberta staff, FortisAlberta reserves the right to disconnect the service completely (including load services) when necessary to conduct regular operations safely.

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 transformer configurations. Refer to DER-02B for more details.

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

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.

5.8. Effective Grounding and Relay De-Sensitization

The DER facility shall meet the effective grounding and relay de-sensitization requirements as defined in DER-02B – FortisAlberta – Effective Grounding Study Requirements for DER Interconnections.

- The DER interconnection (inclusive of DER assets and interconnecting transformer) must be compatible with the feeder grounding practice at the point of interconnection. With some exceptions, installations should meet the requirements for "effectively grounded" as described in IEEE/ANSI C62.92.2 for synchronous machines and C62.92.6 for inverters.
- DERs that require supplemental grounding to meet effective grounding requirements outlined in DER-02B shall install protective relaying that senses if the supplemental grounding has failed. (59G relay). If the supplemental grounding fails, the DER site shall disconnect until repairs or replacements are completed, provided TOV simulations show that the inverter's fast protection cannot effectively ground the DER without the supplemental grounding.
- DERs that require supplemental grounding to meet relay de-sensitization requirements outlined in DER-02B shall install protective relaying that senses if the supplemental grounding has failed. (59G relay). If the supplemental grounding fails, the DER site shall disconnect until repairs or replacements are completed.

5.9. DER Unit Certification

Notwithstanding any DER certification, all DER systems where the measurement point is the point of common coupling (PCC) (typically with a nameplate rating greater than or equal to 500 kVA), regardless of generation type, shall undergo an IEEE Conformity Assessment Program (ICAP) evaluation as outlined in DER-02D, DER-02E and Section 5.9.4 of this standard.

For all individual DER systems and multiple unit DER systems:

5.9.1. Inverter based DER Systems Certification

- UL 1741 SB certifications are required prior to energization.
- Only inverters which are certified shall be connected to the FortisAlberta distribution system

5.9.2. Machine Based DER Systems Certification

- All Machine type generators must undergo an IEEE Conformity Assessment Program (ICAP) evaluation as per Section 5.9.4 of this standard. Machine type generators certified to UL1741 SB and less than a nameplate rating of 500 kVA is exempt from the ICAP evaluation. This is not applicable to machine-based generators used for backup purposes only or machine-based generators less than 150 kW.
- Machine type generators that have had their Detail Level Study application submitted prior to 1-January-2024 may have their machine type generators certified to CSA 22.2 No. 100 Motors and Generators, UL2200, or equivalent. UL1741 SB certification is still recommended as all requirements shall still be met in this standard.

5.9.3. Wind Turbine Generators Certification

- Type I and Type II Wind Turbine Generators shall be certified to applicable machine-based standards as per Section 5.9.2 of this standard.
- Type III and IV Wind Turbine Generators shall be certified to applicable inverter-based standards as per Section 5.9.1 of this standard.

5.9.4. IEEE ICAP Evaluation

- All DER systems where the measurement point is at the PCC (typically with a nameplate rating greater than or equal to 500 kVA) (certified or uncertified), regardless of generation type, shall undergo an IEEE Conformity Assessment Program (ICAP) evaluation as outlined in DER-02D and DER-02E.
- Wind turbine generators and some machine-based generation may be unable to meet certification requirements in Sections 5.9.1, 5.9.2 and 5.9.3. In these cases, the DER facility shall engage qualified contractors to perform the IEEE Conformity Assessment Program (ICAP) for evaluation of conformity to IEEE Std. 1547-2018 as outlined in DER-02D and DER-02E for uncertified equipment.
- FAI can deny connection of any DER system for any non-conformance of standards. This will be at the sole discretion of FAI.

5.10. Measurement Accuracy

DER facility shall meet the accuracy requirements from IEEE 1547-2018 (Section 4.4).

It should be noted that low energy analogue (LEA) voltage measurement devices may be unable to meet the necessary accuracy requirements. Owners should consult equipment specifications to ensure compliance.

5.11. Voltage/Power Control Requirements

The DER system shall be operating in fixed power factor mode at the PCC but also be capable of the modes of operation listed in IEEE 1547-2018. FortisAlberta shall provide a recommended power factor, however the DER owner can specify their own power factor set point. If the DER trips on overvoltage and was operating closer to a unity power factor than what was specified by FortisAlberta, FortisAlberta support will be limited.

DER Units may use different voltage control modes to manage voltage within the 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 FortisAlberta. Under agreement between the FortisAlberta and the DER operator, control modes and implementations other than the ones listed above may be permitted.

For systems consisting of one or more DER units and a central controller, the DER owner is responsible for maintaining reliable performance of the system as a whole in accordance with the standard. Where one or more DER units loses communication and fails to perform as a result, the DER owner remains responsible for the aggregate performance of the facility at the measurement point. Equipment damage, demand charges, or other impacts arising from loss of communications remain the responsibility of the DER owner.

If the DER system changes control modes at the PCC (e.g. to grid forming, from constant power factor to Volt Var etc.), the studies specified in DER-02A, DER-02B and DER-02C (if applicable) shall be resubmitted along with the updated models.

5.12. Reactive Power Requirements

The DER facility shall meet the Reactive Power Requirements detailed in IEEE 1547-2018 (Section 5.2)

5.13. Cease to Energize Performance Requirement

DER facility shall meet the Cease to Energize requirements of IEEE 1547-2018 (Section 4.5)

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.

5.14. DER Aggregation Requirements

If multiple DERs are proposed for connection by the same or similar customer within the same geographical area or feeder, FortisAlberta may, at its sole discretion, aggregate these DERs into a single site for the purposes of connection assessment, management, or interconnection requirements. E.g. a customer applies for two separate DER connections, each with a capacity of 149 kVA, and these connections are on the same feeder, the utility may aggregate these applications into a single 298 kVA DER for evaluation and connection purposes.

5.15. Multiple Unit DER Aggregation Requirements

Aggregation of Multiple Unit DERs: All interconnections shall be treated as a single DER system per metered connection, regardless of the time at which any given DER unit was installed. Where DER units are added to a local EPS (single metered site), the customer shall ensure the DERs are integrated into a single system for protection and control as per the requirements of this standard. The local DER communication interface (SCADA) shall be presented as a single aggregate connection.

5.16. Overhead DER Facilities

DER facilities that are overhead and interconnecting with FortisAlberta owned overhead infrastructure, shall be built to a standard equivalent to FortisAlberta standards, including bird proofing of the DER owned overhead facilities.

5.17. Microgeneration isolation requirements

5.17.1. For Microgeneration DER facilities that are utilizing built in inverter protection at the unit level:

- An inter-tie breaker is required to separate the generation from the load of the customer facility.
- The inter-tie breaker shall trip when an abnormal system condition is detected. For example, if an overvoltage occurs and the inverter shuts down, a transfer trip signal shall be sent to the inter-tie breaker to physically isolate the DER from the distribution system. This is not applicable to DERs less than 150 kW.
- The inter-tie breaker shall be capable of being manually locked out. This is not applicable to DERs

less than 150 kW.

5.17.2. For sites with generation where the measurement point is at the PCC, the inter-tie breaker must be capable of open/close feedback and be capable of complying with monitoring and control requirements specified in Section 8 of this standard.

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 C235-19.

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” (PQ-SPEC-01) document shall not be exceeded at the PCC. These RVC limits shall apply to sudden changes due to frequent energization of transformers, switching of capacitors or from abrupt output variations caused by DER misoperation.

6.3.2.1. Any DER interconnection that has a total transformer capacity (sum of the capacities of all the transformers) greater than 400 kVA shall not create an RVC greater than those specified in FortisAlberta’s PQ-SPEC-01. An engineering study as per DER-02A and commissioning tests are required to confirm compliance. Where DER facilities generate an RVC greater than those specified in PQ-SPEC-01, mitigation measures are required. NOTE: Operating procedures are considered an acceptable mitigation measure but must be submitted to as part of the engineering studies to be approved by FortisAlberta.

6.3.2.2. For sites that energize all interconnection transformers infrequently (such as annual maintenance), the engineering study as per DER-02A will be submitted to and approved by FortisAlberta on a case-by-case basis. If the RVC is deemed excessive by FortisAlberta, further mitigations are required. The infrequent RVC shall not exceed the limit of IEEE 1453-2022, if the limit is exceeded then further mitigations are required. The infrequent RVC limit includes:

- The minimum voltage resulting from the event, as measured at the PCC, shall be no less than 0.88 times the initial voltage.
- After four 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 C235-19 limits.

6.3.2.3. If the transformer energizations cause power quality issues to the service area after the DER site has been energized and in operation, then it is solely the customer’s responsibility to mitigate regardless of the study.

6.4. Harmonic Distortion

Current harmonics limits shall comply with IEEE 1547-2018, the DER system shall not inject a DC current greater than 0.5% of the DER system rated output current.

Inter-harmonic limits, and telephone interference limits as specified in the "FortisAlberta Power Quality Specifications" document shall be met by the DER system.

Note: FortisAlberta utilizes interharmonic frequencies inside the bandwidths listed in Table below for the purposes of the Automated Metering System (AMR). Customers shall not cause interference with the operation of the AMR by creating noise or by sinking the AMR signal. If FortisAlberta determines that a customer facility is interfering with the AMR signal, it is a customer's responsibility to modify the service to correct the problem within a timely manner.

Table 1 – AMR bandwidths

AMR Bandwidth		
>300 Hz to <800 Hz	>900 Hz to <1080 Hz	>2,000 Hz to <5,000 Hz

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.

6.6. Power Quality Monitor Requirements for Benchmark/Compliance Report

The power quality monitor equipment for the purpose of power quality benchmark/compliance report shall be installed at the PCC on customer side and conforming to the latest version/edition of IEC 61000-4-30 Class A measurement standards (10 Minutes interval). Revenue grade metering sensors shall be used. DERs categorized as Small-Scale Generation are not exempt from this requirement.

The first report (PQ Pre-Energization benchmark) shall include 7-day monitoring results and raw data prior to the In-Service-Date for the initial benchmark purposes.

The second report (PQ Post-Energization Compliance Report) shall include 7-day of continuous monitoring results (must include normal generation periods) and raw data post energization of the generation facility to ensure compliance of the DER facility.

The report shall include tables/graphs of following parameters at a minimum:

- Voltage and current RMS (Line to Neutral), max/min/average
- Voltage unbalance
- Individual voltage and current harmonics (up to 50th harmonics as minimum)
- Individual voltage and current interharmonics (up to 50th harmonics as minimum)
- Flicker (Pst and Plt)
- Real power (P), Reactive Power (Q), and Power Factor (PF) of every phase
- Transformer Energization RVC results (must include both single and all transformer energization voltage and current RMS captures) according to 61000-4-30 methods for measurements. Note, RVC tests are performed outside of the 7 days compliance period.

Note: Refer to "DER PQ Benchmark/Compliance Report" template and the sample for detailed report format, instructions, and example.

6.6.1. Power Quality Data Exchange

All power quality raw data presented in both reports shall be send to FortisAlberta along with the report as attachments. The data format could be in IEEE 1159.3 PQDIF file format or in excel files. Refer to "DER Sample PQ data" excel template.

6.7. Real and Reactive Power Oscillations

The active and reactive power of the DER shall not oscillate by more than 5% from the active or reactive power set point during steady state operation.

7. Response to Abnormal Conditions Requirements

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

7.1. Microgeneration

7.1.1. MGs shall be treated as an export DER. The export amount is to be determined by the DER and submitted to FortisAlberta for evaluation. For example, a 1 MVA MG that has a minimum load of 0.6 MVA will export a maximum of 0.4 MVA. The MG will be treated as a 0.4 MVA DER within this standard, with exception any short circuit analysis. This export amount will be known as the export limit.

7.1.2. For MGs that have an export limit that is less than their rating, the following is required at the PCC relay:

- A 32R relay shall be set to trip within 30 seconds if the export power (flowing from the DER site to FortisAlberta) raises above the export limit.
- A 67/67N relay may be required at the sole discretion of FortisAlberta. If required, the pickup setting shall be the rated current of the export limit plus 1% and the trip time shall be 1 second unless otherwise specified by FortisAlberta.

7.2. Shall Trip Requirements

All **DER Units** shall comply with the default shall trip requirements for Category II for inverter interfaced generation or doubly fed induction generation and Category I for synchronous/induction generation per Section 6.4.1. of IEEE 1547-2018.

All **DER Systems** shall comply with the following trip requirements, where the measurement point is at the PCC. An IPSC form shall be completed and provided to FortisAlberta when the measurement point is at the PCC. DERs less than 150 kW/ 167kVA shall not be required to implement the OV1 trip requirement unless otherwise stated by FortisAlberta.

NOTE: All voltage trip elements shall be measured and tripped based on line-to-neutral voltages.

NOTE: The clearing times specified in Section 7.2 must remain constant during system frequency deviations. A stand-alone SEL-351 relay, because it trips based on system cycles,

does not meet this requirement as its trip times lengthen during frequency drops. An SEL-651 or SEL-751, utilizing time-based tripping, would be compliant with the shall trip requirements.

Table 2 – Voltage Trip Requirements @ PCC

Inverter-Based Generation			Machine-Based Generation		
Trip Function	Voltage (% of nominal voltage)	Clearing Time (s)	Trip Function	Voltage (% of nominal voltage)	Clearing Time (s)
OV3	120	0.16	OV3	120	0.16
OV2	110	2	OV2	110	2
OV1	106	45	OV1	106	45
UV1	88	10	UV1	88	2.0
UV2	45	0.16	UV2	45	0.16

Table 3 – Frequency Trip Requirements @ PCC

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

7.3. Ride Through Requirements

All **DER Units** shall comply with the voltage and frequency ride-through requirements for Category II for inverter interfaced generation or doubly fed induction generation and Category I for synchronous/induction generation per IEEE 1547-2018.

~~Ride-through settings shall be submitted in the 110-day package and reviewed prior to commissioning of the DER facility.~~

Note – The design criteria shall match the default minimum ride-through time (s) and maximum response time (s) identified in IEEE 1547-2018.

7.4. Anti-Islanding

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

7.4.2. DER facilities shall meet the anti-islanding requirements listed below in Table 12.

7.4.3. 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.

7.4.4. Anti-Islanding Studies may be required by the transmission owner, please refer to DER-02A - FortisAlberta Engineering Study Requirements.

Table 12 – DER Facility Anti-Islanding Requirements

Generation Type	Aggregate Capacity	Direct Transfer Trip (DTT)	Anti-Islanding Method
Synchronous	< 4 MVA	FAI to Review	Passive[1]
	≥ 4 MVA	Required	DTT
Grid Following Inverter-Based	All	FAI to Review[4]	Active[2]
Induction	< 4 MVA	Not Required	Passive[1]
	≥ 4 MVA	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 UL 1741 SB
[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.

7.4.5. Passive Anti-Islanding

Passive anti-islanding schemes shall use, at a 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. A list of typical islanding detection methods is given in *Annex A*. If the scheme is not approved by FAI, a direct transfer trip will be required. For DERs less than 150 kW, the anti-islanding scheme is not required to be submitted to FortisAlberta unless otherwise specified by FortisAlberta.

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).

7.4.6. 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. A list of typical islanding detection methods is given in *Annex A*. For DERs less than 150 kW, the anti-islanding scheme is not required to be submitted to FortisAlberta unless otherwise specified by FortisAlberta.

7.4.7. Transmission / Substation Anti-Islanding

Anti-islanding requirements proposed by the TFO or the AESO are separate requirements from FortisAlberta and are required as specified by the TFO and the AESO. Anti-islanding communication with the TFO or the AESO shall be the responsibility of the DER Owner.

7.4.8. 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 12; **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) as per FAI Standard D08-08.4. An informative demonstration of customer and FAI equipment responsibilities is given in Figure 1 and Figure 2. The DER owner is responsible to transmit the DTT signal from the FAI control box to the DER owner facility and initiate a Joint Use Agreement (JUA) with FAI as per D08-08.4.

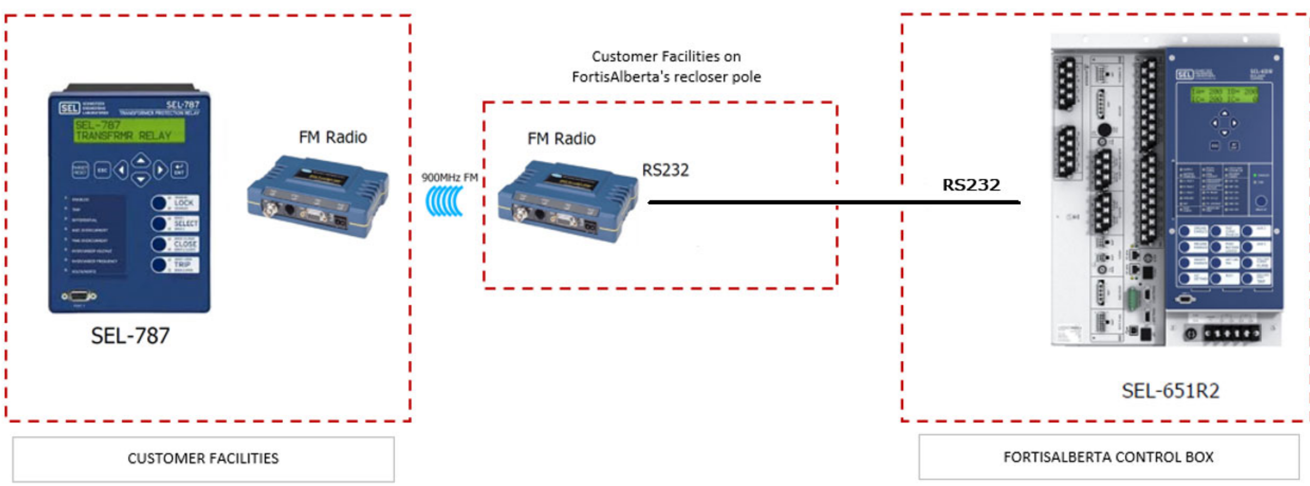

Figure 1 - Equipment Responsibilities DTT for Radio Signals

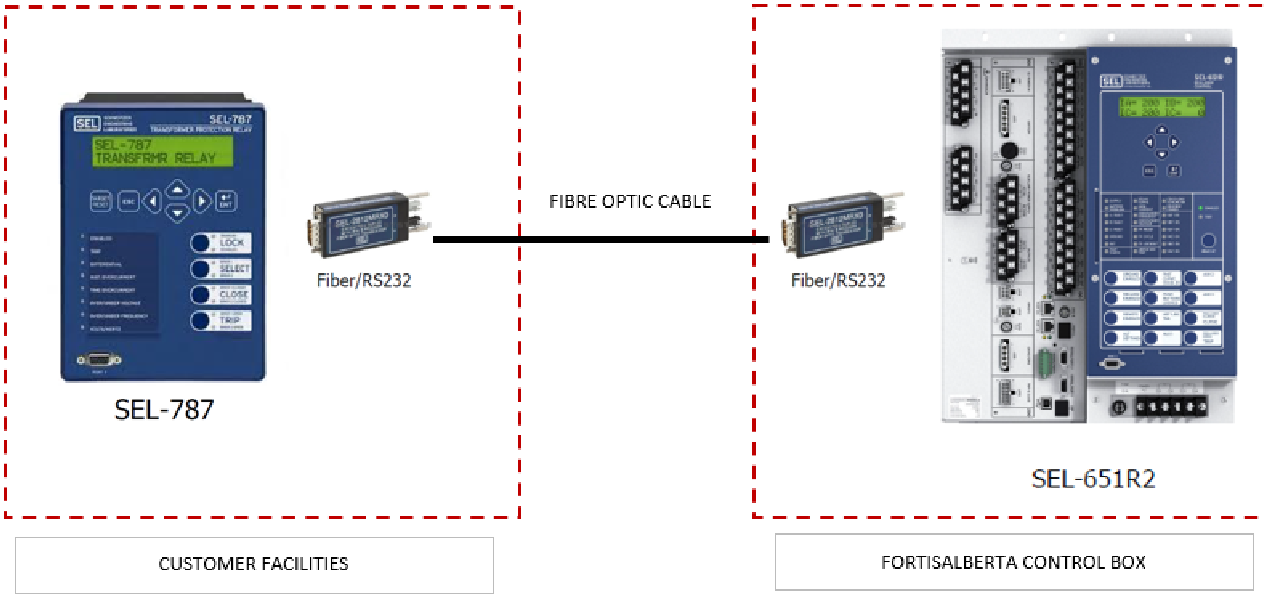

Figure 2 -Equipment Responsibilities DTT for Hardwired Fibre Optic Cables

The design for the DER owner 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. FAI requires the use of *Mirrored Bits* (Schweitzer Relay Protocol) for a DTT.

c) The DTT signal shall 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 facility owner will be required to determine DTT communication requirements

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

7.5. Enter Service and Synchronization

DER facility shall meet the enter service and synchronization requirements from IEEE 1547-2018 (Section 4.10.2). Default settings shall be used unless otherwise specified by FortisAlberta.

7.5.1. 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.

7.6. Breaker Failure

7.6.1. DER facilities with an aggregate output > 500 kVA 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. This device must be able to interrupt on a fault.

7.6.2. 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.

7.6.3. 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.

7.6.4. DER facilities ≤ 500 kVA 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.

7.6.5. DER facilities less than 150 kW are not required to implement breaker fail protection unless otherwise specified by FortisAlberta.

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

7.7. Distribution System Faults

7.7.1. 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.

7.7.2. 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. DER facilities less than 150 kW are not required to submit an IPSC document unless otherwise specified by FortisAlberta.

7.8. Non-Export Directional Protection

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

7.8.1.1. The 32R relay shall be set to trip within 30 seconds if the import power (flowing from FortisAlberta to the DER site) falls below 10% of the load demand.

7.8.1.2. A 67/67N relay may be required at the sole discretion of FortisAlberta. If required, the pickup setting shall be the rated current of the export limit plus 1% and the trip time shall be 1 second unless otherwise specified by FortisAlberta.

7.8.2. 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.

7.9. DERs rated higher than the export limit

7.9.1. DER sites that have a nameplate rating higher than their export limit shall install additional protective elements to prevent excess power delivery. Example 1, a site with a 20 MW DER with a 20 MW export limit that adds a 20 MW Battery Energy Storage System: the site is only allowed to export 20 MW at any time. Example 2, a site with an export limit of 20 MW with generators that are capable of exporting 21 MW: the site is only allowed to export 20 MW. For both Example 1 and Example 2, Section 7.9.2 shall apply to the DER.

7.9.2. For DER sites that have an export limit that is less than their name plate rating, the following is required at the PCC relay:

7.9.2.1. A 32R relay shall be set to trip within 30 seconds if the export power (flowing from the DER site to FortisAlberta) raises above the export limit.

7.9.2.2. A 67/67N relay may be required at the sole discretion of FortisAlberta. If required, the pickup setting shall be the rated current of the export limit plus 1% and the trip time shall be 1 second unless otherwise specified by FortisAlberta.

7.9.2.3. IEEE 1548-2018 Table 3 states that the minimum measurement accuracy for active and reactive power is ±5%. FortisAlberta assumes there is no measurement error when assigning export limits. The DER shall manage their own risks of nuisance tripping due to measurement inaccuracies.

7.10. Open Phase Protection

The DER system must be capable of detecting 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.

7.11. 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 kVA and the measurement point is NOT at the PCC.

DER facilities shall have the provision for monitoring the disconnecting device at the PCC/PoC. (Refer to *Annex C* 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 - The measurement point is at the PCC (typically for total DER System Generation < 500 kVA) (typically for total DER System Generation ≥ 500 kVA)

- A SCADA connection to FortisAlberta's shall be required.
- A data concentrator is required. The data concentrator, typically an SEL RTAC, shall be capable of operating as a master controller to change voltage control modes for all inverters if the DER site is inverter based, i.e., solar sites.
- The data concentrator shall be an SEL RTAC (file extension .exp) or an EATON (file extension .par).
- All communication and parameter mapping requirements outlined in *Annex C* 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 IEEE 1547-2018 Chapter 10).

8.4. Close Block Requirements

For Class 2 DER sites (typically greater than 500 kVA), when enabled by FortisAlberta, the main DER breaker on site cannot be closed. The close block functionality shall be interlocked to prevent closure of the breaker under any and all operating conditions when Close Block is enabled. Any attempt at breaker closure MUST FAIL when Close Block is enabled. No bypass functionality of any kind (e.g. maintenance bypass) shall be provided within the design and implementation. DER owners may not bypass this interlock for any reason without written approval from FortisAlberta. This function may be used by FortisAlberta for operational purposes.

9. Energization Package Requirements

9.1. During the construction phase of the project, there are 5 packages that are required before the in-service date (ISD) of the project and 1 required post.

9.2. The dates below are approval dates, DER owners should submit deliverables in advance to avoid delay of their ISD. For every day past an approval date, the DER ISD shall be delayed by the same number of days. As an example, submitting the 110-day package precisely 110 days before the ISD will delay the ISD. Therefore, it is strongly advised to submit all packages well in advance of cutoff dates to avoid pushing back the ISD.

9.3. If any deliverables are missing or FortisAlberta requests revisions before the deadlines, the full gates package must be resubmitted, pushing the process timeline by the number of days exceeded. For example, if a 110-day package is submitted at 130 days before the in-service date (ISD) and revisions are requested 100 days before, the ISD moves back 10 days.

9.4. For projects with AESO deliverables: All AESO deliverables shall be submitted to FortisAlberta who shall pass the deliverables to AESO. DER owners are shall not pass AESO deliverables directly to the AESO.

9.5. Each package below shall be treated as a stage. These stages must be completed, in order, for projects to continue its advancement towards interconnection. Signed gate letters shall be issued to DER owners by FortisAlberta following the completion of each stage's package allowing the project to progress.

9.6. For customers who do not request to be connected as a load the load energization and 30-day package stage will be approved simultaneously.

9.7. The following packages/gates are required:

Construction Energization Packages		
Package	**Required Approval Date**	**Required Items**
110 Day	110 days prior to the In-Service-Date	- Authenticated SLD - Issued for Construction (IFC) - IFC Technical Data Form - Site Layout - Engineering Studies (as applicable) ▪ Final Effective Grounding Study ▪ Final Short Circuit Study ▪ Transformer Inrush/Rapid Voltage Change Study ▪ Self-Excitation Study - Communication/Telecom Equipment Assessment - DER Unit Certifications - ICAP report including Pre-Site Evaluation. - DER Inverter Settings (if applicable) (if not applicable submit a sheet stating not applicable and why) - IPSC – Section 1 – Proposed Settings - Final Commissioning plan & schedule - Power Quality Benchmark Monitoring Plan, refer to Section 6.6 - SCADA - Data Concentrator - DNP Points List - 100-day AESO deliverables
Load Energization	30 days prior to the In-Service-Date	- IPSC – Section 2 - Load Protection Performance and Equipment Commissioning - 110 day package gate letter - Electrical Services Agreement (for station service load) - Meter Verification Certificate - Proof of site IDs being enrolled with a retailer. - Proof that the electrical permit is on site and at the meter. - Electrical Permit - Complete and signed interconnection site work plan.
30 Day	30 days prior to the In-Service-Date	- Data Concentrator Bench Test Report ~~- Data Concentrator file (.exp or .par)~~ - Power Quality Pre-Energization Benchmark Report, refer to Section 6.6 - Updated ICAP report including On-Site Protection Evaluation. - Operating Procedures - Switching Procedures Submitted - Certificate of Insurance - Joint Use agreement in place (if applicable) - AESO Asset ID - Load energization gate letter (if granted before the 30 day package) or load energization gate deliverables (if not previously approved to energize as a load) - 30 day AESO deliverables
Commissioning	Prior to commercial operation	- IPSC – Section 3 - Generation Protection Performance and Equipment Commissioning - Updated ICAP report including On-Site Performance Evaluation. - Connection Authorization Form / Signed Permit - As built site SLD - 30 day package gate letter - EMTP-RV and PSCAD inverter models (for inverter-based generation) - Detailed modelling data (e.g., transient reactance, time constants etc.) for non-inverter based generation.

Operations / Post in-service-date	Required no later than 45 days post commercial operation	- Power Quality Post Energization Compliance Report, refer to Section 6.6 - Metering Field Installation Test Report - As-Built Communication Block Diagram - As-Built RAS Logic Diagram - Maintenance Verification Plan / Schedule (See section 10) - Commissioning gate letter

Note: Failure to meet the required timelines above will result in a delay to the ISD.

Note: FortisAlberta reserves the right to disconnect the DER owner's generation assets should the Operations/ Post in-service-date deliverables not be provided, and an operations gate letter issued by FortisAlberta.

10. Commissioning Requirements

10.1. The DER Owner is fully responsible for the inspection, testing, and calibration of its equipment, at the PCC using applicable testing standards.

10.2. A commissioning schedule is required in the 110-day package and shall include the following:

- a. ~~Testing SLD – Including test points, device(s) under testing (DUT) and PQ monitoring point(s).~~
  - a. ~~Lock out and tag out procedures shall be provided in the commissioning plan.~~
  - b. ~~Lock out and tag out points shall be highlighted on the SLD.~~
- b. ~~A list of DUTs and tests to be performed. *Refer to Clause 10.7*~~
- c. ~~Testing methodology for each test or reference to the applicable standard and section (e.g., NETA ECS, Section 10.1).~~
- d. Tentative testing schedule where FortisAlberta staff will be required including (but not limited to)
  - a. Installation of the SCADA box.
  - b. Preliminary SCADA point to point testing. NOTE: DER Owners shall complete bench testing that conforms to the FortisAlberta DNP map prior to testing with FortisAlberta.
  - c. Witness testing with IPSC Section 2, 3 and SCADA.
- e. Completed IPSC Section 1 – Proposed Settings
  - a. The IPSC Document should reference the facility PCC breaker relay. Inverters and/or generator protection do not require a completed IPSC form.
- f. ~~Commissioning parties responsible for the testing and their qualifications.~~
- g. This plan shall confirm the contents above and provide a finalized commissioning schedule. The schedule must include a date and time for FortisAlberta SCADA commissioning and a date and time for witness testing. FortisAlberta must review and confirm this schedule prior to approval of the commissioning plan. *Review clause 10.7 for testing and witness activities.*
- h. ~~NOTE: the commissioning plan is a summary. It should only include applicable tests as specified in FortisAlberta's Interconnection Protection Settings and Commissioning Documents.~~
- i. The IPSC Section 2 shall be completed with results prior to any FortisAlberta staff attending witness testing.
- j. Changes to the commissioning schedule require a minimum of 45 days notice before energization. FortisAlberta cannot guarantee representatives will be available if less than 30 days notice is provided.
- k. FortisAlberta reserves the right to leave commissioning activities if the commissioning activities deviate from the submitted commissioning schedule. FortisAlberta will require a minimum of 45 days to reschedule commissioning activities, from the date the new commissioning schedule is received.

10.3. GIS Documents: The GIS documents shall contain the facility layout or site plan. GIS documents shall be provided with the 110-day package submission. The files shall be formatted as follows:

10.3.1. Shapefiles are to be provided with the below files – Files should use a common coordinate system/projection: UTM 11/12, 10TM, 3TM or Geographic.

- *.SHP
- *.DBF
- *.SHX
- *.PRJ

10.3.2. The land base and equipment shall be provided on separate layers or levels for CAD files or have proper attribution in SHP files.

10.3.3. If shapefiles cannot be produced, .DGN or .DGW files will be acceptable and must be provided with the following:

- Coordinate system, projection, and units shall be embedded in the drawing metadata. Please ensure that the drawing's units match the coordinate system used.
- Land base and equipment shall be provided on separate layers/ levels
- Legal Land boundary must be clearly indicated in the file

10.4. The DER owner shall perform a bench test of the Data Concentrator (RTU). The results of the bench test shall be submitted to FortisAlberta in the 30-day Package and must be approved by FortisAlberta prior to point-to-point testing and witness testing. The RTU bench test shall include, but is 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 with the mapping presented in *Annex C.* The report shall also contain a copy of the configuration parameters of the RTU.

10.5. The DER generating equipment must be isolated until the PCC breaker is commissioned, IPSC Section 2 submitted and approved by FortisAlberta. All commissioning test results, supportive of Section 2, shall be recorded and made available to FortisAlberta upon request.

10.6. The IPSC Section 2 and 3 will be reviewed in accordance with the procedure outlined in Annex B.

10.7. A Power Quality report confirming an initial benchmark, and 7-days review of the DER facility post energization shall be provided to FortisAlberta to ensure compliance with all PQ requirements.

10.8. Interconnection equipment, protection, and performance testing shall include, but is not limited to, the following:

*E – Interconnection Equipment *Pr – Interconnection Protection *Pf – System Performance

Equipment and System Performance Tests

Item		Testing Reference	Requisite	Witness Testing
E	Power Transformers (MV)	- Manufacturers Recommendations - Industry Acceptance Testing Standards. i.e. NETA	- Documentation is not required to be submitted for energization approval. - Testing Documentation shall be made available upon request.	Not Required
E	Grounding Transformers / NGRs			
E	Instrument Transformers (PT / CT)			
E	Breakers / Isolation Devices			
E	Cabling			
Pr	Interconnection Relay Trips / Alarms (Voltage / Current / Frequency Settings)	- Manufacturers Recommendations - Industry Acceptance Testing Standards. i.e. NETA - FortisAlberta DER-02 - *Section 7* Requirements	- Complete IPSC Section 2 & 3. Document required for energization. - Testing Documentation shall be made available upon request.	Required (Function Test)
Pr	Breaker Failure (BF) Scheme	- FortisAlberta DER-02 - *Section 7* Requirements		
Pr	Transfer Trip (Including communication trip)			
Pr	Anti-Islanding (3 Phase, Open Phase, Deadbus)			
Pr	Return to Service			
Pr	Remote Trips to FortisAlberta Device (Ground Fault, BF)	- FortisAlberta DER-02 - *Section 7* Requirements		
	SCADA point-to-point Testing	- Trip Breaker - Close Block - Supervisory Control	- These points must be tested with the field technician after point-to-point testing is completed.	
Pf	Transient Overvoltage (LROV, GFOV)	- FortisAlberta DER-02B – *Section 5* Requirements	- Complete IPSC Section 3. May require energization of the DER facility and must be a part of the commissioning plan. (if required) Refer to DER-02B. - PQ Report Displaying Cease to Energize Performance	Not Required
Pf	Voltage / Frequency Ride Through	- FortisAlberta DER-02 - *Section 7* Requirements	- Documentation is not required to be submitted for energization approval. - Testing Documentation shall be made available upon request.	

	Power Quality	- FortisAlberta DER-02 - *Section 6* Requirements	- PQ Pre-Energization Benchmark Report - PQ Post-Energization Compliance Report	

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.

10.9. Recommissioning

Recommissioning is required, under certain circumstances, after the original commissioning and witness testing is completed. The extent of recommissioning is dependent on the reason for the commissioning and the effect on the DER interconnection. Any recommissioning shall require an updated IPSC to be submitted for approval by FortisAlberta.

Circumstances that will result in recommissioning of the DER system are:

a) Operating modes or interconnection settings have been changed after the initial commissioning process.

b) If any field operational and performance issues due to power quality arise.

c) Replacement or changes of critical infrastructure.

10.10. Energizing as a Load

FortisAlberta representatives shall have the ability to place a lock out and tag out on the aggregated generation prior to energizing the facility as a load, as specified herein. The DER facility shall not energize as a load unless the generators have been isolated by physical locks which are in the control of FortisAlberta. This may be achieved using adequate controls and procedures which have been approved by FortisAlberta.

DER facilities that are not able to isolate the generation through lock out and tag out procedures shall not be able to connect to the distribution system until IPSC Section 2 has been approved. DER facilities owners, their consultants, and contractors shall make provisions for appropriately testing the facility without being connected to the distribution system, if the load and generation can not be isolated.

11. Maintenance Requirements

11.1. 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 reserves the right to inspect all test reports and associated test results at its sole discretion.

11.2. 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)

11.3. 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)

Typical Islanding Detection Methods

Table A1 can be used as a reference when completing the IPSC form to submit to FortisAlberta.

Table A1 – Typical Islanding Detection Methods

	Islanding Detection Method	Characteristics
Passive	Rate of change of frequency (RoCoF) & vector shift	Passive methods, not limited to RoCoF and vector shift, monitor specific power parameters to identify changes that indicate loss of the grid. There are no alterations to the output current for the purpose of islanding detection. Alterations include over/underfrequency, over/undervoltage, rate of change of frequency, vector shift (phase), harmonic level or negative sequence voltage.
Active	Slip-mode frequency shift (SMS)	SMS uses positive feedback to detect islanding conditions, a phase shift is introduced by changing the phase angle of the current waveform at the PCC. During islanding, there are perturbations in frequency of the PCC voltage. The phase shift causes phase error (function of the positive feedback) to increase until islanding is detected. It can be applied to the amplitude, frequency, and phase of the voltage.
	Active frequency drift (AFD) or frequency bias	AFD uses positive feedback and monitors any changes in the impedance at fundamental frequency through testing the drift between the current and voltage. Under islanding conditions, the frequency of utility voltage drifts up or down, increasing the natural frequency drift. Once the natural frequency drift exceeds a threshold, islanding is detected.
	Sandia frequency shift (SFS)	SFS uses frequency drift with positive feedback to monitor fluctuations in frequency. When there is a change in frequency, SFS tries to increase it. Under islanding conditions, the stiffness of the grid is no longer present to prevent SFS from increasing the frequency. Once the frequency has a large enough deviation, islanding is detected.
	General Electric frequency shift (GEFS)	GEFS uses positive feedback and varies the output power injected by the inverter and monitors the variation in voltage and frequency. GEFS increases the frequency under islanding conditions, allowing detection.
	Sandia voltage shift (SVS)	SVS uses positive feedback on the amplitude of the voltage at the PCC. Under islanding conditions, there is a reduction in voltage amplitude at the PCC due to the grid's absence. This leads to a reduction in the inverter output current, thus reducing the voltage further which indicates a loss of the grid.
	Harmonic injection	Harmonic injection method injects current (continuous or time-varying) at a specific frequency. Detection is based on the correlation between the injected current and the voltage at those harmonic frequencies.
	Negative sequence current injection (NSCI)	Negative sequence current injection manipulates the negative sequence current to detect islanding. This method applies positive feedback to the negative sequence current based on changes seen on the negative sequence voltage.

Annex B (Normative)

IPSC SECTION 2 and 3 REVIEW PROCEDURE

This is the procedure in place for collecting IPSC Section 2 documentation. The IPSC Section 2 must be submitted before the DER may receive permission to generate.

B1. IPSC Section 2 Review

1. Following submission, FortisAlberta will review the IPSC Section 2.
2. The Generation Facility Operator (GFO) is not allowed to generate until the IPSC Section 2 is approved by FortisAlberta.
   i) No point-to-point testing/commissioning is required for parts of a site that are to be connected strictly as a load.
3. The DER generating equipment must be isolated until the PCC breaker is commissioned, IPSC Section 2 submitted and approved by FortisAlberta.
4. If there are issues with, or clarifications required for, the Section 2, P&C will notify the GFO.
5. IPSC Section 2 results shall be tested prior to FortisAlberta representatives being made available on site.
6. NOTE: Any issues identified by FAI with the IPSC Section 2 must be addressed by the GFO and approved by P&C before permission to generate may be granted.

B2. Section 2 IPSC Review Procedure for Sites with Non-Compliant Results

This procedure is used for sites where the Section 2 has non-compliant results.

1. FortisAlberta may request Section 2 be recompleted.
2. FAI can request the relay commissioning documentation be submitted if the results are still non-compliant, or for validation.
3. Following a review of the relay commissioning documentation by FAI (or if the relay testing sheets are not provided), if the results are still non-compliant the site will require a new third-party tester to complete the results for the IPSC Section 2. The GFO will be responsible for arranging witness testing with member of FAIs team (the witness team). Results will need to be confirmed and signed off by the witness team before the site is permitted to re-submit results for approval.

B3. IPSC Section 3 Review

1. Following submission, FortisAlberta will review the IPSC Section 3.
2. If there are issues with, or clarifications required for, the Section 3, P&C will notify the GFO.
3. NOTE: Any issues identified by FAI with the IPSC Section 3 must be addressed by the GFO and approved by P&C within 30 days following AESO ISD (FAI energization date), unless otherwise authorized by FortisAlberta.
4. If the GFO misses the 30-day timeline, FortisAlberta has the right to disconnect the site due to safety concerns. Written notice will be provided a week before the 30 days lapses as the site may be disconnected.

B4. Section 3 IPSC Review Procedure for Sites with Non-Compliant Results

This procedure is used for sites where the Section 3 has non-compliant results.

1. FortisAlberta may request Section 3 be recompleted.
2. FAI can request the relay commissioning documentation be submitted if the results are still non-compliant, or for validation.
3. Following a review of the relay commissioning documentation by FAI (or if the relay testing sheets are not provided), if the results are still non-compliant the site will be turned off and the GFO will be responsible for arranging witness testing with member of FAIs team (the witness team). Results will need to be confirmed and signed off by the witness team before the site is permitted to reconnect.

Annex C (Normative)

SCADA Requirements & DNP3 Parameter Mapping

C1. 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.

C1.1. 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 C4) 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

C1.2. 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 Server DNP Address: 1 Client DNP Address: 65000

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

C1.3. 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.

C2. 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 the main DER isolating device (i.e., breaker) remotely.

C2.1. 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).

C3. DNP3 MAPPING

Table C3.1 – DNP3 Mapping – Binary Inputs

DNP3 Index #	Signal	State 1 "0"	State 2 "1"	Class	Variation	Details
000	Trip / Fault Indication	NORMAL	TRIP	1	2	Trip indication of the main DER Facility breaker.
001	52A - Breaker Status (Open/Closed)	OPEN	CLOSE	1	2	Open/Closed status of the main DER Facility breaker.
002	Phase A Fault	NORMAL	FAULT	1	2	Overcurrent fault (A phase) anywhere in DER System.
003	Phase B Fault	NORMAL	FAULT	1	2	Overcurrent fault (B phase) anywhere in DER System.
004	Phase C Fault	NORMAL	FAULT	1	2	Overcurrent fault (C phase) anywhere in DER System.
005	Ground Fault	NORMAL	FAULT	1	2	Overcurrent fault (Ground/Neutral) anywhere in DER System.
006	Close Block (Enabled by FortisAlberta ONLY)	NORMAL	CLOSE BLOCK	1	2	When enabled by FortisAlberta, the main DER Facility breaker on site CANNOT be closed. This functionality must be available when the breaker is in LOCAL or REMOTE. Any breaker CLOSE command from on site or sent by FortisAlberta MUST FAIL when Close Block is enabled.
~~007~~	~~Aux. Battery Healthy (if applicable)~~	~~FAIL~~	~~NORMAL~~	~~1~~	~~2~~	~~Battery status for main DER facility controller.~~
~~008~~	~~RTU Relay Healthy~~	~~FAIL~~	~~NORMAL~~	~~1~~	~~2~~	~~Indicator for any sort of failure of main DER facility relay.~~
009	Utility Fault	NORMAL	FAULT	1	2	A fault on the distribution system, i.e., FortisAlberta.
010	Supervisory Control	LOCAL	REMOTE	1	2	FortisAlberta Control Room Operators can only send commands to the main DER Facility breaker when the controller is in REMOTE. All commands aside from CLOSE BLOCK sent by FortisAlberta MUST FAIL when the controller is in LOCAL. A toggle for this point MUST be available locally on the controller.
011	Armed for FFR (if requested)	OFF	ACTIVE	1	2	Fast Frequency Response (FFR). Only required if requested.
012	Armed for CR (if requested)	OFF	ACTIVE	1	2	Contingency Reserve (CR). Only required if requested.
013+	Reserved Binary Inputs for future use					
~~100~~	~~Generator 1 - Status (On/Off)~~	~~OFF~~	~~ON~~	~~1~~	~~2~~	~~Required if the DER facility does not have a central controller.~~

DNP3 Index #	Signal	State 1 "0"	State 2 "1"	Class	Variation	Details
~~200~~	~~Generator 2 - Status (On/Off)~~	~~OFF~~	~~ON~~	~~1~~	~~2~~	~~Required if the DER facility does not have a central controller.~~
~~300~~	~~Generator 3 - Status (On/Off)~~	~~OFF~~	~~ON~~	~~1~~	~~2~~	~~Required if the DER facility does not have a central controller.~~
~~400+~~	~~Binary Inputs for additional generators~~					

Table C3.2 – DNP3 Mapping – Analog Inputs

DNP3 Index #	Signal	Class	Variation	# of Decimal Points	Deadband	Details	
000	Current Magnitude A (Amps)	2	3	1	1	A phase (Line to Neutral) current in Amps[1]	e.g., 20.1A
001	Current Magnitude B (Amps)	2	3	1	1	B phase (Line to Neutral) current in Amps[1]	e.g., 20.1A
002	Current Magnitude C (Amps)	2	3	1	1	C phase (Line to Neutral) current in Amps[1]	e.g., 20.1A
003	Current Magnitude N (Amps)	2	3	1	1	Neutral current in Amps[1]	e.g., 20.1A
~~004~~	~~Distribution - Voltage Magnitude A (kV)~~	~~2~~	~~3~~	~~2~~	~~1~~	~~Distribution A phase (Line to Neutral) Voltage in kV~~	~~e.g., 14.41kV~~
~~005~~	~~Distribution - Voltage Magnitude B (kV)~~	~~2~~	~~3~~	~~2~~	~~1~~	~~Distribution B phase (Line to Neutral) Voltage in kV~~	~~e.g., 14.41kV~~
~~006~~	~~Distribution - Voltage Magnitude C (kV)~~	~~2~~	~~3~~	~~2~~	~~1~~	~~Distribution C phase (Line to Neutral) Voltage in kV~~	~~e.g., 14.41kV~~
007	Voltage Magnitude A (kV)	2	3	2	1	A phase (Line to Neutral) Voltage in kV[1]	e.g., 14.41kV
008	Voltage Magnitude B (kV)	2	3	2	1	B phase (Line to Neutral) Voltage in kV[1]	e.g., 14.41kV
009	Voltage Magnitude C (kV)	2	3	2	1	C phase (Line to Neutral) Voltage in kV[1]	e.g., 14.41kV
010	Active Power three-phase (MW)	2	3	3	1	Three phase Active Power in MW[1]	e.g., 5.023MW
011	Reactive Power three-phase (MVAR)	2	3	3	1	Three phase Reactive Power in MVAR[1]	e.g., 2.951MVAR
012	Apparent Power three-phase (MVA)	2	3	3	1	Three phase Apparent Power in MVA[1]	e.g., 8.644MVA
013	Frequency (Hz)	2	3	2	1	Frequency in Hz[1]	e.g., 60.01Hz
014	Power Factor (%)	2	3	2	1	Power Factor in %[1]	e.g., 99.92%
015	Fault Current A (Amps)	2	3	1	1	Most recent A phase overcurrent fault current in Amps[1]	e.g., 400.2A
016	Fault Current B (Amps)	2	3	1	1	Most recent B phase overcurrent fault current in Amps[1]	e.g., 400.2A
017	Fault Current C (Amps)	2	3	1	1	Most recent C phase overcurrent fault current in Amps[1]	e.g., 400.2A
018	Fault Current G (Amps)	2	3	1	1	Most recent Neutral overcurrent fault current in Amps[1]	e.g., 400.2A
90	Facility Master Controller Voltage Control Mode[2]	2	3		0	The DER Facility central controller voltage control mode. Required if the DER Facility is inverter based (i.e., solar sites). See Voltage Control Modes below table for analog setpoints.[2]	

DNP3 Index #	Signal	Class	Variation	# of Decimal Points	Deadband	Details
91	Enter Service Delay (seconds) 1s – 600s (default 300s)	2	3		1	The DER facility must delay a specific time before closing the main DER Facility breaker to connect to the distribution system which has just recently energized. Minimum default delay is 300 seconds (5 minutes). As per IEEE 1547. Analog value indicates number of seconds to delay.
92+	Reserved Analog Inputs for future use					
~~100~~	~~Generator 1 – Control Mode~~	~~2~~	~~3~~		~~0~~	~~Required if the DER facility does not have a central controller.~~
~~101~~	~~Generator 1 – Active Power Output (MW)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~102~~	~~Generator 1 – Reactive Power Output (MVAR)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~100 to 199~~	~~Reserved Analog Inputs for future use~~					
~~200~~	~~Generator 2 - Control Mode~~	~~2~~	~~3~~		~~0~~	~~Required if the DER facility does not have a central controller.~~
~~201~~	~~Generator 2 – Active Power Output (MW)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~202~~	~~Generator 2 – Reactive Power Output (MVAR)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~200 to 299~~	~~Reserved Analog Inputs for future use~~					
~~300~~	~~Generator 3 - Control Mode~~	~~2~~	~~3~~		~~0~~	~~Required if the DER facility does not have a central controller.~~
~~301~~	~~Generator 3 – Active Power Output (MW)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~302~~	~~Generator 3 – Reactive Power Output (MVAR)~~	~~2~~	~~3~~	~~3~~	~~1~~	~~Required if the DER facility does not have a central controller.~~
~~300 to 399~~	~~Reserved Analog Inputs for future use~~	~~2~~	~~3~~	~~3~~		
~~400+~~	~~Analog Inputs for additional generators~~					

[1] All Analogs must be measured at the PCC.

[2] Voltage Control Modes:

	Constant Power Factor Mode	= 0
	Voltage-Reactive Power Mode	= 1
	Active Power-Reactive Power Mode	= 2
	Constant Reactive Power Mode	= 3
	Voltage-Active Power Mode	= 4

Table C3.3 – DNP3 Mapping – Binary Outputs

DNP3 Index #	Signal Type (Analog/Binary)	Signal	Command Out On Output Type	Command Out Off Output Type	Details
000	Binary Output	52A – Main Breaker Open		Trip/Pulse-On	FortisAlberta command to open the DER Facility main breaker. Based on SEL Object 12 Control Relay Operations.
~~001~~	~~Binary Output~~	~~52A – Main Breaker Closed~~	~~Close/Pulse-On~~		~~FortisAlberta command to close the DER Facility main breaker. Based on SEL Object 12 Control Relay Operations.~~
002	Binary Output	FortisAlberta – Close Block	Close/Pulse-On	Trip/Pulse-On	When enabled by FortisAlberta, the main breaker on site CANNOT be closed. This functionality must be available when the breaker is in LOCAL or REMOTE. Any breaker CLOSE command from on site or sent by FortisAlberta MUST FAIL when Close Block is enabled. May be used for operational purposes.

Table C3.4 – DNP3 Mapping – Analog Outputs

DNP3 Index #	Signal Type (Analog/Binary)	Signal	Details
90	Analog Output	Facility Master Controller - Control Mode[1]	The DER Facility central controller voltage control mode. Required if the DER Facility is inverter based (i.e., solar sites). See Voltage Control Modes below table for analog setpoints.[1]
91	Analog Output	Enter Service Delay (seconds) 1s – 600s (default 300s)	The DER facility must delay a specific time before closing the main DER Facility breaker to connect to the distribution system which has just recently energized. Minimum default delay is 300 seconds (5 minutes). As per IEEE 1547. Analog value indicates number of seconds to delay.
~~100~~	~~Analog Output~~	~~Generator 1 – Mode Selection~~	~~Required if the DER facility does not have a central controller.~~
~~101-199~~	~~Analog Output~~	~~Reserved Analog Outputs for future use~~	
~~200~~	~~Analog Output~~	~~Generator 2 – Mode Selection~~	~~Required if the DER facility does not have a central controller.~~
~~201-299~~	~~Analog Output~~	~~Reserved Analog Outputs for future use~~	
~~300~~	~~Analog Output~~	~~Generator 3 – Mode Selection~~	~~Required if the DER facility does not have a central controller.~~
~~301-399~~	~~Analog Output~~	~~Reserved Analog Outputs for future use~~	
~~400+~~	~~Analog Output~~	~~Reserved Analog Outputs for additional generators~~	

[1] Voltage Control Modes:

Constant Power Factor Mode	= 0
Voltage-Reactive Power Mode	= 1
Active Power-Reactive Power Mode	= 2
Constant Reactive Power Mode	= 3
Voltage-Active Power Mode	= 4

C4. Communication Interconnection Diagram