AESO DER ROADMAP INTEGRATION PAPER

DER Anti-islanding Screening and Study Guideline

SEPTEMBER 2022

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1. Introduction

As discussed in the *AESO Distributed Energy Resources (DER) Roadmap*[1], the growth of distributed energy resources (DERs) and their integration with the Alberta interconnected electric system (AIES) will drive significant changes for the AESO, distribution facility owners (DFOs), transmission facility owners (TFOs), market participants, and consumers in Alberta. As DER penetration continues to grow, the increasing complexity and scale of power systems in Alberta may present reliability challenges concerning AIES operations and coordination of planning between the distribution and transmission systems. One of these challenges concerns unintentional islanding of the AIES.

Islanding refers to a condition in which a portion of an electric system, containing both load and generation, becomes isolated from the rest of the system and continues to operate (*i.e.*, the system and its constituent components are "islanded"). Unintentional islanding is generally considered undesirable for the following reasons:

- Abnormal voltage and frequency excursions outside of acceptable ranges may result in power quality issues and could potentially damage facilities.
- There may be safety concerns associated with a portion of the electric system remaining energized by the operation of islanded energy sources because personnel may be conducting work under the mistaken assumption that the system is fully disconnected from all energy sources.
- Asynchronous reclosing (reconnecting) of islands to the rest of the electric system could cause damage to the generating facilities, especially rotating machines, in the islanded portion of the system. Out-of-synch reclosing can result in a large current swing, which may also result in the operation of protection schemes that in turn can trigger undesired trips in the broader system.
- There might be concerns associated with the security of the power system protection when the system operates under unintentional islanding condition. This increases the risk of safe detection and clearing of faults given the protection system is not designed for this condition.

Avoiding, managing, and mitigating these impacts requires maintaining adequate protection and control along with proper operating practices over the design and operation of generating facilities, including DERs.

This AESO DER Roadmap Integration Paper examines and recommends an approach for addressing unintentional islanding to ensure the continued safety and reliability of the AIES. In accordance with the AESO's connection process, requirements relating to this approach may be incorporated into the AESO functional specification for a given project, where applicable. Should the AESO determine that authoritative AESO requirements in the form of ISO rules or Alberta reliability standards are necessary in the future, these will be addressed through the applicable authoritative document development processes.

[1] *AESO Distributed Energy Resources (DER) Roadmap* (June 2020), available on the AESO website

2. Background and Purpose

The AESO's legislative duties include directing the safe, reliable and economic operation of the AIES.[2] Given its central role in ensuring the reliability of the AIES, the AESO developed the *AESO DER Roadmap*, which is being advanced in collaboration with stakeholders, to explore and manage the challenges and opportunities associated with the transformation of the AIES.[3]

In July 2019, the AESO established the Technical Performance Exploration Group (TPEG)[4], consisting of technical experts from utilities across Alberta, including DFOs and TFOs, to exchange ideas, discuss DER-related topics, and proactively prepare for a future state with higher DER penetration and potentially rapid growth in DERs. The TPEG focuses on:

- facilitating a common understanding of the overall impacts on the reliable operation and planning of the AIES due to DER integration;
- developing consensus on the future state of DER technical performance;
- proposing recommendations to close any gaps identified between the current and desired future states; and
- supporting the coordination of stakeholders' implementation of recommendations relating to the technical interconnection of DERs in Alberta.

The TPEG's scope of work excludes matters relating to policy and the regulatory framework in Alberta, the electricity market impact of DERs, and various other technical aspects related to DER integration and operation, including modelling, forecasting, and DER management systems (DERMS).

The AESO engaged with the TPEG to determine a common and consistent methodology for dealing with unintentional islanding in the context of DERs. This AESO DER Roadmap Integration Paper:

- provides an update to stakeholders, including DFOs, TFOs, DER proponents and owners (herein simply referred to as "DER owners"), the Alberta Utilities Commission, and other interested parties, about the results of the TPEG's work regarding unintentional DER islanding;
- addresses a methodology specifically for addressing circumstances where DERs are unintentionally islanded with distribution systems <u>and</u> part of the transmission system;[5]
- examines relevant industry practices and standards that informed the development of the AESO's recommended approach to unintentional islanding; and
- sets out the AESO's recommended approaches, developed in collaboration with the TPEG.

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[2] *Electric Utilities Act* (EUA), section 17(h).

[3] AESO DER Roadmap, at PDF 5.

[4] The TPEG membership list is provided in **Error! Reference source not found.**.

[5] Whereas a similar methodology could be used for circumstances where DERs are islanded solely within distribution systems (*i.e.*, to the exclusion of any part of the transmission system), such an assessment is outside the scope of this paper and is expected to remain within the sphere of DFOs' accountability. Nevertheless, the AESO's involvement may be required in special cases, including the synchronization of permitted islands (*e.g.*, micro grids, ISDs) to the transmission system.

This AESO DER Roadmap Integration Paper is also intended to assist interested parties in assessing the potential impacts that the AESO's recommendations may have on them, including current or planned projects, facilities, and services.

3. Objectives and Scope

The need to address the issue of DERs islanding with distribution systems and part of the transmission system is one of the integration activities identified in the *AESO DER Roadmap* (DER Roadmap integration activities). Communication-based anti-islanding schemes (*e.g.*, transfer trips) generally increase development costs, and as such, DER owners often prefer to use local schemes instead to trip the DERs when they become islanded. If a DER owner intends to rely on a local detection scheme to avoid islanded operations, the AESO generally includes a requirement for certain technical studies in the AESO functional specification. These technical studies are aimed at demonstrating that the DER's islanding-detection scheme functions effectively during the lifespan of the DER to avoid sustained unintentional islanded operation under the various and relevant potential islanding scenarios. Ideally, a study is required to demonstrate the effectiveness of the island detection or protection schemes; however, it is not always practical to conduct a study whenever there is a change in the system or for every potential islanding scenario. Further, if a study cannot demonstrate the effectiveness of the local detection scheme for all relevant islanding scenarios, then alternative measures such as communication-based schemes may be necessary.

A key objective of this DER Roadmap integration activity is to develop a screening methodology for determining whether sustained unintentional islanded operation could reasonably occur. In addition to ensuring system reliability, this risk-based approach to anti-islanding promotes the cost-effective integration of DERs into the AIES. If the screening methodology does not identify any instances of sustained unintentional islanding, the DER is considered to have passed the screening process and there would be no need for a detailed study or for alternative measures such as a communication-based scheme. Conversely, a DER is considered to have failed the screening process if the screening methodology identifies the potential for sustained unintentional islanded operation, in which case additional detailed studies or alternative measures, or both, may be required.

The following items are considered in-scope for this DER Roadmap integration activity:

- A review of other jurisdictions' practices and Alberta DFOs' existing interconnection requirements pertaining to unintentional islanding.
- A review of the various editions of IEEE 1547 – *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* (IEEE 1547), published by the Institute of Electrical and Electronics Engineers (IEEE), with respect to anti-islanding.
- A proposed screening methodology, for use in Alberta, to determine the possibility of a DER forming a sustained unintentional island with part of the transmission system.
- A proposed detailed study methodology to prove the effectiveness of a local detection scheme at the DER facility, should the results of the screening process for the relevant islanding scenarios indicate that the DER may form a sustained unintentional island.

The following items are considered out-of-scope for this DER Roadmap integration activity:

- **Intentional islanding of DERs**: Another matter contemplated as part of the DER Roadmap integration activities is to explore the potential capability of DERs in providing blackstart services (*i.e.*, creating sustained intentional islands—in the unlikely event of a system-wide blackout—to re-energize the electric system and provide start-up power to generators who cannot self-start). This is a separate initiative which the AESO plans to advance in 2022/23 to facilitate participation of capable DERs in the provision of blackstart services. It is expected that anti-islanding schemes for such DERs would still be required to allow anti-islanding detection and tripping during normal system operation for relevant islanding scenarios; however, these schemes would be adjusted during blackstart and system restoration to facilitate islanded operation and may thereafter have to be readjusted upon returning to normal operation.

- **DERs islanded solely within a distribution system:** As previously discussed, this issue is expected to remain within the sphere of DFOs' accountability in Alberta.
- **Maintenance requirements for DER anti-islanding local schemes:** Currently, the AESO relies on DFOs' interconnection requirements to specify the maintenance requirements for DER protection and control functions, including anti-islanding schemes.

4. Islanding Detection Methods

Islanding detection methods may be divided into three categories: (1) passive detection methods installed at the DER facility site; (2) active detection methods installed at the DER facility site; and (3) detection methods installed at the utility's site, whereby the islanding status is transferred to the DER facility through communications.[6]

4.1 Passive Methods

Passive methods monitor various parameters (*e.g.*, voltage, frequency) at the DER's terminal, and trip the DER if the selected parameter exceeds a specified threshold. What defines them as passive is that the DER does not actively try to change the value of the parameter being monitored; in other words, passive methods rely on the detection of an abnormality at the point of common coupling (PCC) between the DER and the utility.

Some parameters that have been used in passive anti-islanding methods include the following:

- Over/undervoltage and over/underfrequency
- Voltage phase (the phase is monitored for a sudden jump)
- Voltage or current harmonic distortion (total harmonic distortion (THD))
- Rate of change of frequency (ROCOF)
- Rate of change of real power
- Rate of change of voltage vector[7]
- Various harmonic pattern recognition methods, using Fast Fourier Transforms (FFTs), wavelets, Kalman filters, or other spectral techniques

In general, passive methods have great difficulty eliminating all the Non-Detective Zones (NDZ)[8] because it is difficult to find thresholds or patterns that are totally unique to islanding, and do not occur under normal operating conditions. Thus, passive methods usually involve a trade-off between the extent of the NDZ and the rate of occurrence of nuisance trips. The behavior and performance of passive methods is difficult to predict when multiple resources (transmission-connected resources or DERs) are present in the potential island. In addition, the settings used in passive methods (*e.g.*, frequency, voltage, and ROCOF) will need to be compliant with the ride-through requirements specified in IEEE 1547-2018 in Alberta in the near future[9]. This is particularly important because the loss of DERs due to system-wide disturbances (such as frequency excursions) could result in reliability concerns. For this reason, coordination between anti-islanding and ride-through requirements is a necessity when using passive methods. In general, and at

[6] International Energy Agency, *Evaluation Of Islanding Detection Methods For Photovoltaic Utility interactive Power Systems*, available at: https://iea-pvps.org/wp-content/uploads/2020/01/rep5_09.pdf

[7] Also known as vector shift or out of step (OOS) for large generators

[8] NDZ refers to a situation in which, due to specific operating conditions, the passive methods are not able to detect the islanded condition. Such operating conditions include situations where the DER output closely matches the loading in the island.

[9] The AESO has published a separate AESO DER Roadmap Integration Paper on this subject, outlining the AESO's recommendation that Alberta DFOs adopt specific requirements for purposes of interconnecting DERs to their respective distribution systems. The publication, *DER Ride-Through Performance Recommendations* (March 2021), is available on the AESO website.

minimum, the passive schemes should be compliant with the ride-through requirements associated with Category I for rotating machines and Category II for inverter-based resources (IBRs) in IEEE 1547-2018.

4.2 Active Methods

Active methods largely apply to IBRs. The concept of applying active methods for rotating machines, including synchronous machines, has been explored in literature but has not been widely applied in the industry due to various concerns, including cost, equipment fatigue, and interference with other DERs[10]. For IBRs, active methods are effectively similar to passive methods in that the inverter monitors for some pre-defined threshold to be exceeded. The difference is that the inverter takes an active role in driving the system state toward that threshold. The active islanding detection methods generally contain an active circuit to force voltage, frequency or the measurement of impedance to cause an abnormal condition in the system that can then be detected to help identify islanded conditions and subsequently trip the DER. Active methods are generally more successful than passive methods because they tend to destabilize the potential island by tripping DERs under abnormal conditions, thereby making the generation-load balance—a key requisite for sustained islanded operation—more difficult to achieve.

Active methods include the following:

- **Impedance detection:** In impedance detection, the inverter periodically perturbs its output current and checks to see whether there is a corresponding change in voltage, thereby measuring the source impedance as seen by the inverter. If the detected impedance is too high, the inverter ceases to operate.
- **Positive feedback-based methods:** These methods include slip-mode frequency shift, frequency bias, Sandia frequency shift, Sandia voltage shift, and frequency jump. In these methods, the inverter employs positive feedback on voltage or frequency. If the inverter detects a change in one of these parameters, it attempts to "push" on that parameter in the same direction, trying to drive it out of bounds. If it succeeds, the inverter ceases to operate.
- **Impedance detection plus positive feedback:** Most commercial inverters today use some variant of this technique, in which the benefits of positive feedback are combined with the benefits of impedance detection. This method has been vetted in simulation, laboratory tests, and field deployments.

4.3 Communication-based Methods

In these methods, communications are used to send utility status information back to the inverter, which the inverter can interpret to determine whether an island has been formed. Communications-based methods include the following:

- **Direct transfer trip (DTT):** In DTT, the utility's breaker or other isolation device is tied to a transmitter that sends the breaker's status to the DER facility.

- **Power line carrier communications (PLCC):** PLCC systems send a low-energy communications signal along the distribution line itself. Since the line is used as the communications channel, it is possible to use the PLCC signal to perform a continuity test of the line. If such a PLCC signal is

[10] Wilsun Xu, Konrad Mauch, Sylvain Martel, *An Assessment of Distributed Generation Islanding Detection Methods and Issues for Canada*; http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.131.6506&rep=rep1&type=pd

provided, a simple device installed on the customer side of the PCC can detect the presence or absence of the PLCC signal. If the PLCC signal disappears, this indicates a break in the continuity of the line, and the inverter can be instructed to cease operation.

- **Integration of inverters into utility's SCADA:** In this approach, voltage-sensing devices are installed in the local part of the utility's system, which initiate a trip signal to the DER if the sensors detect the utility source is disconnected from that part of the system.
- **Synchrophasor-based methods:** This method utilizes synchrophasor data collected from the local DER location and a remote location outside of the island to detect the islanded condition[11].
- **Impedance insertion:** In the impedance insertion method, a low-value-impedance, usually a capacitor bank, is installed on the utility's system inside the potential island (normally open). When the island is formed and the utility connection is interrupted, the impedance is inserted with a short delay. The addition of the large capacitor upsets the balance between the generation and load within the formed island, causing a step change in phase ø and a sudden drop in the island's frequency, leading to a frequency decrease that the vector shift or underfrequency protection can detect.

For communication-based methods, the use of fail-safe lockout[12] of the DER upon loss of communications prevents potential islands from forming. With less reliable communication infrastructure, this approach provides assurance against islanding but could also result in unnecessary lockouts. The AESO expects that, with increasing DER penetration, it will become necessary in the future to ensure the combined total capacity of DERs with fail-safe lockout on a common commercial telecommunication network does not exceed Alberta's most severe single contingency. The AESO may in the future determine that BPS reliability requires the development and maintenance of a list of DERs and their communication links to help monitor and track the loss of DERs and other generation that use communication-based schemes for anti-islanding protection during a single-event loss of communications. Such an initiative would entail stakeholder engagement consistent with the AESO's Stakeholder Engagement Framework, and would include TFOs, DFOs, and DER owners.

During the TPEG meetings, the AESO presented for consideration certain mitigation strategies to minimize the impact of fail-safe telecommunications; for example, one strategy would be to ensure that the tripping of DERs upon communication loss could only occur where abnormal voltage, frequency, or ROCOF was concurrently detected.

[11] Michael Mills-Price, Mesa Scharf, Steve Hummel, Michael Ropp and Dij Joshi, Greg Zweigle, Krishnanjan Gubba Ravikumar, and Bill Flerchinger, *Solar Generation Control With Time-Synchronized Phasors* (2011), available online at https://cms-cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6453_SolarGeneration_GZ_20110217_Web.pdf?v=20190325-150906

[12] The fail-safe lockout refers to a situation in which, due to the loss of communication between the DER facility and utility site(s) for a certain time period, the DER is tripped offline to avoid the risk of a sustained unintentional islanding.

5. IEEE 1547 Requirements

IEEE 1547 specifies minimum technical interconnection and interoperability requirements for DERs. This standard was first published in 2003 and has gone through two major revisions since then, with the 2018 version being the most recent version. IEEE 1547-2018 significantly enhances and expands the required levels of performance and functional capability for DERs connecting specifically to primary and secondary distribution systems. These new capabilities align with the needs of the "bulk power system"[13] (BPS) and present opportunities for maintaining or improving BPS reliability with increasing DER penetration.

The following subsections briefly cover the IEEE 1547-2018 requirements related to islanding and abnormal frequency and voltage. It should be noted that the requirements outlined in IEEE 1547-2018 are not binding unless adopted by an implementing agency (regulatory body, DFOs or TFOs), and that these requirements have not yet been adopted in Alberta. The AESO is currently working with DFOs and TFOs as part of the *AESO DER Roadmap* implementation process to determine the appropriate technical requirements in IEEE 1547-2018 for adoption in Alberta.

5.1 Islanding

IEEE 1547-2018 covers the islanding of a DER in the context of unintentional and intentional islanding. For an unintentional island, Clause 8.1.1 in the standard requires the DER to "detect the island, cease to energize the grid, and trip within two seconds of the formation of an island." (emphasis added) The same clause clarifies the important requirement that ride-through requirements as specified in Clause 6 of the standard shall still be maintained. The latest version of IEEE 1547 requires that DER anti-islanding performance be demonstrated with the widest voltage and frequency tripping set points and with grid support functionality (voltage regulation and frequency droop) enabled.

5.2 Frequency and Voltage Ride-Through and Must Trip

Clauses 6.5.1 and 6.5.2 define the abnormal frequency response in terms of the must trip and ride-through requirements for Category I, II, and III resources in Tables 18 and 19 of IEEE 1547-2018, respectively. The must trip and ride-through tables are reproduced below. In general, it can be observed that the must trip settings in IEEE 1547-2018 are wider than IEEE 1547-2003, which are used as the basis for the Sandia guideline[14].

Table 18 —DER response (shall trip) to abnormal frequencies for DER of abnormal operating performance Category I, Category II, and Category III (see Figure H.10)

Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Frequency[c] (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s)
OF2	62.0	0.16	61.8–66.0	0.16–1 000.0
OF1	61.2	300.0	61.0–66.0	180.0–1 000.0
UF1	58.5	300.0[c]	50.0–59.0	180.0–1 000
UF2	56.5	0.16	50.0–57.0	0.16–1 000

[13] As contemplated in IEEE 1547-2018.

[14] M. Ropp, et al., *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk*, SAND2012-1365, Sandia National Laboratories (2012), available online at http://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf.

Table 19 —Frequency ride-through requirements for DER of abnormal operating performance Category I, Category II, and Category III (see Figure H.10)

Frequency range (Hz)	Operating mode	Minimum time (s) (design criteria)
$f > 62.0$	No ride-through requirements apply to this range	
$61.2 < f \leq 61.8$	Mandatory Operation[a]	299
$58.8 \leq f \leq 61.2$	Continuous Operation[a,b]	Infinite[c]
$57.0 \leq f < 58.8$	Mandatory Operation[b]	299
$f < 57.0$	No ride-through requirements apply to this range	

[a]Any DER shall provide the frequency-droop (frequency-power) operation for high-frequency conditions specified in 6.5.2.7.

[b]DER of Category I may provide the frequency-droop (frequency-power) operation for low-frequency conditions specified in 6.5.2.7. DER of Category II or Category III shall provide the frequency-droop (frequency-power) operation for low-frequency conditions specified in 6.5.2.7.

[c]For a per-unit ratio of Voltage/frequency limit of $V/f \leq 1.1$.

IEEE 1547-2018 also specifies voltage must trip and ride-through requirements. Clause 6.4.1 includes the mandatory voltage trip settings and ranges of adjustability for Category I, II, and III in Tables 11-13. The standard also defines the voltage ride-through requirements for three categories in Tables 14-16 (presented below). Similarly, it can be observed that the must trip settings in IEEE 1547-2018 are wider than IEEE 1547-2003, with Category I having the closest settings to IEEE 1547-2003.

Table 11 —DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category I (see Figure H.7)

Shall trip—Category I				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	2.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0

Table 12 —DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category II (see Figure H.8)

Shall trip—Category II				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	10.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0

Table 13—DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III (see Figure H.9)

Shall trip—Category III				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	13.0	1.10–1.20	1.0–13.0
UV1	0.88	21.0	0.0–0.88	21.0–50.0
UV2	0.50	2.0	0.0–0.50	2.0–21.0

Table 14—Voltage ride-through requirements for DER for abnormal operating performance Category I (see Figure H.7)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	Linear slope of 4 s/1 p.u. voltage starting at 0.7 s @ 0.7 p.u.: $T_{\mathrm{VRT}} = 0.7\ \mathrm{s} + \dfrac{4\ \mathrm{s}}{1\ \mathrm{p.u.}}(V - 0.7\ \mathrm{p.u.})$	N/A
$0.50 \leq V < 0.70$	Permissive Operation	0.16	N/A
$V < 0.50$	Cease to Energize[a]	N/A	0.16

Table 15—Voltage ride-through requirements for DER of abnormal operating performance Category II (see Figure H.8)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{\mathrm{VRT}} = 3\ \mathrm{s} + \dfrac{8.7\ \mathrm{s}}{1\ \mathrm{p.u.}}(V - 0.65\ \mathrm{p.u.})$	N/A
$0.45 \leq V < 0.65$	Permissive Operation	0.32	N/A
$0.30 \leq V < 0.45$	Permissive Operation	0.16	N/A
$V < 0.30$	Cease to Energize[a]	N/A	0.16

Table 16—Voltage ride-through requirements for DER of abnormal operating performance Category III (see Figure H.9)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.10 < V \leq 1.20$	Momentary Cessation[b]	12	0.083
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	20	N/A
0.50[c] $\leq V < 0.70$	Mandatory Operation	10	N/A
$V <$ 0.50[c]	Momentary Cessation[b]	1	0.083

6. Current State in Alberta

As a matter of internal AESO practice,[15] the AESO does not intentionally plan the transmission system to operate any electrical islands based on a transmission topology with one or two elements out of service (*i.e.*, N-1 and N-1-1conditions), subject to a few exceptions as follows:

- Islands in the AESO's power system restoration plans developed in accordance with applicable Alberta reliability standards
- Industrial systems designated as such by the Alberta Utilities Commission, commonly known as "ISDs" (*e.g.*, ISDs located in the Fort McMurray area)
- Unintentional islands that could form under N-1-1 conditions and which are not covered by existing anti-islanding schemes[16]

When responding to a market participant's system access service request, the AESO typically requires that wire owners (mainly TFOs) or generating facility owners install adequate measures to prevent islanded operation. These measures, which are intended to ensure the continued reliability of the AIES, are generally stipulated in the AESO functional specification for a given project and are the result of collaborative efforts and information-sharing between the parties involved in the DER interconnection process. However, if an unintentional electrical island were to form in the real-time operational domain, the AESO would determine in real time whether to terminate or continue operating the electrical island. After the fact, the AESO may direct TFOs and DFOs as needed to make necessary changes in the system to either avoid the unexpected island recurring or to allow an intentional islanding on a prospective basis through operating procedures and practices.

[15] The practices referred in this section are the AESO's internal practices and not part of the ISO rules or Alberta reliability standards.

[16] The existing anti-islanding schemes (specifically transfer trip schemes) may not cover all N-1-1 topologies on the transmission system, in which case the AESO, on a case-by-case basis and in coordination with TFOs, ensures that the risk of unintentional islanding is managed if and when the island is formed (as opposed to preventing the island from forming in the first place). This is accomplished by a combination of operating procedures, planned outage coordination, and protection and control equipment; for example, blocking auto reclose (operator action) or installing synch check relays (protection and control equipment) to address the risk of out-of-synch closing.

7. Jurisdictional Review

The AESO conducted a jurisdictional review to examine the current state of anti-islanding practices in different regions across North America. Several utilities and system operators in Canada and the United States, with functionalities broadly similar to the AESO, were selected for this jurisdictional review. As part of the jurisdictional review, the AESO examined publicly available materials, portions of which are summarized below. Notably, the characteristics of the various jurisdictions' power systems may differ, and the DER penetration levels and growth rates vary substantially depending on the regions. Therefore, reliability needs may differ from region to region. The AESO's jurisdictional review provides a summary for information and reference purposes only; it is not exhaustive and is not determinative of the anti-islanding approach that should apply in Alberta.

7.1 BC Hydro[17]

7.1.1 Anti-Islanding

BC Hydro does not allow a Power Generator (PG) without planned islanding capability to form an island to avoid the risk of damaging equipment due to abnormal voltage or frequency during inadvertent islanding. The PG should promptly disconnect from the feeder automatically when the PG becomes isolated from the BC Hydro system. Proper protection (over/under voltage and over/under frequency relays) is required to initiate PG disconnection. BC Hydro typically does not transfer trip from line reclosers or the substation feeder breakers to the PG facility.

BC Hydro has developed a "Two-to-One" rule-of-thumb to estimate if a PG can inadvertently island the BC Hydro feeder, part or all of the distribution substation or the transmission line that supplies the substation. The "Two-to-One" rule is based on the assumption that an island is not sustainable where the annual minimum load in the island is at least twice the island's total generation. In other words, in the event that a PG with generation capacity x MVA and BC Hydro customer loads of 2x MVA form an island, then the PG's protection and control will shut down the PG[18]. The "Two-to-One" rule-of-thumb aids in determining if PG interconnection technical studies will be done for a given BC Hydro system "element", i.e. feeder, substation bus, entire substation, or transmission line. Some utilities use a more conservative "Three-to-One" rule of-thumb.

7.1.2 Prevention of out of sync reclosing

To prevent out of sync reclosing of DER islands to the rest of system, BC Hydro requires PG to install protection for the possibility of an out-of-synchronism reclose from line reclosers, automatic reclosing breakers and supervisory reclose of feeder breakers. Alternatively, BC Hydro voltage supervision with synchronism check may be implemented at the line reclosers in the feeder. At BC Hydro substations, feeder auto-reclose and manual close may have voltage supervision and synchronism check to prevent out-of-sync closing.

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[17] BC Hydro, *35 kV and Below Interconnection Requirements for Power Generators* (June 2006).

[18] The AESO interprets this to mean that, under the relevant conditions, the PG will trip off without the need for or reliance on a dedicated anti-islanding protection scheme.

7.2 Hydro One Limited[19]

Distributed Generation (DG) Facility generation cannot remain connected to any part of the Hydro One Distribution System in island mode. Hydro One has the following requirements for DG anti-islanding:

- Upon loss of voltage in one or more phases of Hydro One's Distribution System, the DG Facility shall automatically disconnect from Hydro One's Distribution System within 500 ms.
- The DG Owner shall demonstrate to Hydro One that it shall not sustain an island for longer than the above time requirements.
- All DG Facilities shall have anti-islanding protection. This may involve different protection functions; however, all DG Facilities shall have:
    a) Under/Over Frequency protection
    b) Under/Over Voltage protection and
    c) Transfer Trip for anti-islanding protection may be required

- DG Facilities ≤500 kW shall be exempted from the transfer trip requirement and allowed to install the following passive anti-islanding schemes in lieu of transfer trip as an interim protection until Hydro One standardizes on a transfer trip solution for DG Facilities ≤500 kW:
    a) Rate of Change of Frequency (ROCOF); and
    b) Vector Surge or Reverse Reactive Power
- The passive anti-islanding protection scheme shall be submitted to Hydro One for approval.
- The passive anti-islanding protections referred above shall be set as sensitive as possible to reduce the non-detection zone and can be changed in the future if it is found to cause unjustified nuisance trips. These settings changes shall have to be pre-approved by Hydro One prior to implementation.
- The DG Owner shall be aware and accept the consequences of utilizing passive anti-islanding schemes as a primary anti-islanding protection and shall not hold Hydro One responsible for any damage incurred due to islanded operation from events such as out-of-phase reclosing.
- DG Facilities ≤500 kW shall have provision for the capability to receive Hydro One trip signals and cease generation; *i.e.*, shall have provision for the installation of equipment required to accommodate standardized transfer trip solution for DG Facilities ≤500 kW. The actual implementation is not required but may be requested by Hydro One at a later date to be implemented at the DG Owner's cost within 90 days.

7.2.1 Transfer Trip Requirements

- A Transfer Trip (TT) signal from the station feeder breaker(s) to the DG Facility shall be required for all DG Facilities whose aggregate capacity is 1 MW or larger.
- Transfer Trip (TT) signal from the feeder breaker(s) and/or upstream recloser(s) (where the recloser is located between the DG Facility and feeder breaker) to the DG Facility shall be required for any or all of the following conditions:
    a) When the aggregate DG Facility capacity is greater than 50% of the minimum feeder load or the minimum load downstream of recloser(s); or

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[19] Hydro One Limited, *Distributed Generation Technical Interconnection Requirements Interconnections At Voltages 50 kV And Below, DT-10-015 REV. 3* (March 2013).

b) When the aggregate generation, comprising of existing generation, other earlier proposed DG Facilities, and the concerned DG Facility is greater than 50% of the minimum feeder load or minimum load downstream of the recloser; or
c) If the existing reclosing interval of the feeder breaker(s) and/or upstream recloser(s) is less than 1.0 s.

- A Transfer Trip (TT) signal from transmission line terminal breaker(s) of an upstream Transformer Station (TS) to the DG Facility shall also be required if the TS where the DG Facility is being proposed is radially supplied by that transmission line and there is a possibility of islanding of the entire transmission line, or where Wide area islands could exist – aggregate generation on transmission line is greater than 50% of the minimum load on the transmission line. This signal will be cascaded onto the TT signal that will be required between the TS feeder breaker and the DG Facility.
- Upon loss of the Transfer Trip (TT) communication channel, the generation and HV ground sources shall disconnect within 5 seconds of the channel failing. A controlled shutdown may be allowed and must be submitted to Hydro One for approval.
- DG Facilities with an aggregate capacity of 500 kW and less, may be exempted and permitted to use passive anti-islanding protections.

7.2.2 Prevention of the out-of-synch reclosing

Hydro One requires DG facilities to provide Distributed Generator End Open (DGEO), which is a real-time signal that is continuously sent from the DG Facility to the Hydro One supply source breaker or recloser. It establishes the connection status of the generation equipment. Hydro One utilizes this signal for auto-reclose supervision of the feeder breaker or any upstream protective device. This will ensure that out-of-phase reclosing of the DG Facility does not occur.

7.3 SaskPower[20]

SaskPower's requirement is that the generation facilities of 100 kW and above connected onto SaskPower's distribution system are not permitted to operate as an island. All generation facilities shall be equipped with protection systems to detect islanded conditions and cause the generator to cease to deliver power to SaskPower's system within 2 seconds. The generation owner must demonstrate to SaskPower through analytical studies that the generation protection system is capable of detecting an island condition and isolate the facility. Failure to do so may result in additional measures such as transfer trips for which the generation owner is responsible to cover the cost. SaskPower power provides the necessary information (*e.g.*, loading) for the purpose of the study to the generation owner.

For generation facilities less than 100 kW, SaskPower relies on local protection schemes at the generation facility to detect an island and isolate the facility.

7.4 Pacific Gas and Electric Company (PG&E)[21]

PG&E does not allow unintentional islanding of DERs for generating facilities of 100 kW and above in alignment with the requirements specified in California Public Utility Commission (CPUC) Rule 21. PG&E's

[20] SaskPower, *Generation Interconnection Requirements at Voltages 34.5kV and Below* (March 2005).

[21] PG&E, *Distribution Interconnection Handbook* (2017).

minimum protection requirements are designed and intended to protect the PG&E system. The customer is responsible for the costs of PG&E's installation of any protective equipment necessary to ensure safe and reliable operation of both PG&E's and the customer's facilities. The need for protective equipment will vary, depending on the type, and the size of generation and the facility's location within a PG&E circuit.

For a generating facility that cannot detect distribution or transmission system faults (both line-to-line and line-to-ground) or the formation of an unintended island, and cease to energize distribution provider's distribution or transmission system within two seconds, the distribution provider may require a transfer trip system or an equivalent protective function.

Where the aggregate generating facility capacity exceeds 15% of the peak load on any automatic reclosing device, the distribution provider may require additional protective functions, including, but not limited to reclose-blocking on some of the automatic reclosing devices. PG&E also recommends that IBRs be certified to Underwriters Laboratories (UL) Standard UL 1741 and be on the California Energy Commissioner's (CEC) list of eligible inverters. Non-Certified inverters will be subject to additional protection requirements.

7.5 Xcel Energy Inc.[22]

Xcel Energy requires accidental isolation or islanding of DERs to be avoided by having the correct protective relaying installed by the customer as required under IEEE 1547. Interconnection studies (depending on the size and DER certification) are performed to prove local anti-islanding protection is adequate for a timely disconnection of the DER. Transfer trips from the transmission or distribution system are the alternative when studies indicate local anti-islanding protection is marginal or inadequate to disconnect the DER. Small size inverter-based DERs which are certified with UL Standard 1741 are exempt from submitting separate test reports but remain subject to the anti-islanding assessment.

To prevent out-of-sync reclosing, voltage-supervision-of-reclosing (VSR), also referred to as hot-line reclose blocking (HLRB), are required whenever a feeder or line segment may have reverse power flow, at least part-time, during the year. To ensure safe recloses, VSR is normally required whenever the ratio of minimum load to generation is less than 2. The presence of substantial size rotating generators, motors, and capacitors on a feeder or line segment will require VSR if the minimum-load-to-generation ratio is less than 2. Where out-of-sync reclosing may cause conditions that will damage other customers, HLRB, TT, or other measures may be required. Especially for large DG, these requirements may also apply to the transmission line that supplies the substation. This is at customer cost.

7.6 Central Hudson Gas & Electric Corporation (Central Hudson)[23]

No DER System shall be allowed to island with any part of the Central Hudson system unless it is a part of an approved microgrid. When reviewing an Interconnection Customer's application, Central Hudson performs a study to determine the DER System's risk of islanding. If it is determined that there exists a

[22] Public Service Company of Colorado d/b/a Xcel Energy Inc., *Safety, Interference and Interconnection Guidelines for Cogenerators, Small Power Producers and Customer-Owned Generation* (2017).

[23] Central Hudson, *Interconnection Requirements for Distributed Energy Resources Connected in Parallel with the Central Hudson Electric Delivery System* (December 2019).

possibility of islanding, the Interconnection Customer shall be responsible for utility reinforcements to mitigate this risk. These may include, but are not limited to:

- The installation of a Direct Transfer Trip (DTT) scheme to directly trip the DER System via a communications signal.
- The installation of a Reclose Block (dead line sensing) scheme to block circuit breaker automatic reclosing until the circuit is de-energized.

The more cost-effective option will be applied wherever possible. There are also fail-safe requirements in order to establish redundant protection and control systems. IBRs certified with UL-1741 meet such requirements.

7.7 Eversource Energy[24]

Unintentional Islanding by the DER of all or part of the Electric Power System (EPS) (meaning a part of the EPS is kept energized by the generating facility after the area has been de-energized) is prohibited as it may result in unsafe conditions on the EPS. Similar to the other jurisdictions, Eversource requires special studies to meet its anti-islanding and reclosing requirements; other measures such as DTT from all isolation points may be required at the generator's sole cost and expense. Certification of IBRs with UL 1741 SA is also another check as part of the interconnection requirements. In general, the Eversource interconnection requirements apply to generating units with sizes equal to or greater than 100 kW, with some other requirements for units less than 100 kW and aggregation of IBRs in certain areas.

7.8 FortisAlberta Inc. (FAI)

FAI has two sets of requirements for DERs with sizes greater than or equal to 150 kW and above and DERs less than 150 kW. There are anti-islanding requirements for both sets of requirements; however, the requirements for DERs 150 kW and above size are more stringent and are detailed below[25].

7.8.1 Anti-Islanding Analysis

- All types of generation shall cease to energize and trip within 2 seconds of the formation of an island
- DER facilities shall meet the anti-islanding requirements listed in the table below

[24] Eversource Energy, *Information and Technical Requirements for the Interconnection of Distributed Energy Resources (DER)* (2020).

[25] FortisAlberta Inc., *Technical Interconnection Requirements for DER 150 kW and Greater, DER-02, Version No: 2.0* (August 31, 2020).

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

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

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

7.8.2 Transfer Trip

A direct transfer trip signal from the upstream protection devices will be required based on the following criteria:

- Requirements identified in the above table; or
- Aggregate DER Facility capacity if greater than 33% of the minimum load downstream of recloser(s); (Not Inverter-Based) or
- Results from a transmission anti-islanding / protection study which identify DTT as a requirement for transmission protection or
- The emergence of a non-detection zone.

7.9 ATCO Electric Ltd.[26]

7.9.1 Anti-Islanding

- The DG Owner's generation facility must be equipped with protective hardware and software designed to prevent the generator from being connected to a de-energized circuit owned by the Wires Owner

[26] ATCO Electric, *Standard for the Interconnection of Generators to ATCO Electric's Distribution system* (July 16, 2002).

- At the discretion of the Wires Owner, the DG Owner may install under-frequency tripping and over-frequency tripping for anti-islanding that will not negatively impact WECC criteria, in conjunction with their load shedding schemes
- In most cases, the generation facility will routinely operate as a part of the interconnected system. A problem on the system could lead to the generator becoming islanded (*i.e.*, the generator becomes the sole supplier of power to one or more of the Wires Owner's customers). The resulting irregularities in power quality could cause damage for other customers.
- To prevent this possibility, the DG Owner must use teleprotection signals from the distribution system or another reliable means to separate the generator from the distribution system in the event of islanding. If other means are used to detect islanding, the scheme must consist of reliable primary and backup functions using different quantities.
- The DG Owner is responsible for damage caused as a result of failure to safely separate during an islanding event.
- Where there could be a reasonable match between the DG Owner's generation and the islanded load, conventional methods may not be effective in detecting the islanded operation. In this case, the Wires Owner will require the addition of transfer trip communication facilities to remotely trip-off the DG Owner's generation upon opening the distribution feeder main circuit breaker or circuit recloser.

7.9.2 Requirements for Transfer Trip

- Where transfer trip protection is required, the transfer trip protection must ensure that the generator does not "island" in the event of substation breaker or intermediate OCR operation
- General Requirements are:
  - Generator lockout within 0.6 seconds of breaker or OCR operation; and
  - Fail-safe lockout within 6 seconds of communication loss.
- The DG Owner is responsible for detecting and tripping in the event of a communication loss
- Transfer tripping requirements are also applicable to induction generators, unless the DG Owner can demonstrate that that there is no potential for self-excitation

7.10 EPCOR Distribution & Transmission Inc. (EDTI)[27]

7.10.1 Anti-Islanding Protection

In most cases, the DER facility will routinely operate as a part of the interconnected system. A problem on EDTI's distribution system could lead to the DER becoming islanded and inadvertently acting as the sole power resource for one or more of EDTI's customers. This could result in damages to those customers and liability to the DER provider because of irregularities in power quality. The DER must be equipped with anti-islanding protection designed to prevent the DER from being connected to a de-energized EDTI circuit. The anti-islanding protection should meet the following requirements:

- Upon loss of voltage in one or more phases of EDTI's distribution system, the DER facility shall automatically disconnect from EDTI's distribution system within 0.6 s
- All DER facilities must have passive anti-islanding protection, including:

[27] EDTI, *Technical Guideline for the Interconnection of Distributed Energy Resources to EPCOR Distribution and Transmission Inc.'s Distribution Syste*m (dated January 5, 2017).

    - Underfrequency/overfrequency protection
    - Undervoltage/overvoltage protection
    - Reverse power protection
- All DER facilities shall have active anti-islanding protection, which can be:
    - Sandia Frequency Shift
    - Sliding Mode Frequency Shift
    - Active Frequency Drift
    - Other method approved by CSA or ANSI/IEEE or UL
- The DER provider shall demonstrate to EDTI that it shall not sustain an island for longer than 0.6 s. Transfer trip for anti-islanding protection may be required as stipulated in Requirement for Transfer Trip section. Damages that are caused by a failure to separate safely during an islanding event will be the responsibility of the DER provider.

7.10.2 Requirements for Transfer Trip

No international or national standard specifies the minimum DER rating at which transfer trip (TT) is required. However, EDTI should set up the threshold for TT installation on a DER site to avoid DERs running in islanding mode. In general, the minimum load on a 15 kV or 25 kV circuit is about 2,000 kVA. If a DER with 1,000 kW rating is connected to a circuit without TT, it is possible for the DER to run in islanding mode to feed the customers on the circuit when the circuit breaker is open[28]. Therefore, all synchronous generators and inverter-based generators that are rated 1,000 kW or larger with the ability to export power onto EDTI's distribution system must be equipped with transfer trip protection or an EDTI-approved anti-islanding relay that performs the equivalent function of transfer trip. This is to ensure that these generators do not island in the event of a substation breaker or intermediate automatic circuit recloser opening. General requirements are as follows:

1. A DER end-open signal must be sent to EDTI's circuit breaker relay to make sure the breaker is safe to reclose after tripping on a fault.
2. Generator lockout or lockout of the main breaker (for DER facilities that want to operate in isolation) must occur at the point of common coupling location within 0.6 s of the EDTI substation circuit breaker or the automatic circuit recloser opening.
3. Fail-safe lockout must occur within 6 s of communication loss.
4. The DER provider is responsible for detecting and tripping in the event of communication loss.

If transfer trip protection is installed for a DER, the DER must operate on the specified circuit. When the DER is transferred to another circuit from the specified circuit, the DER must be turned off.

Synchronous generators and inverters of less than 1,000 kW may also require this protection, depending upon the characteristics of the particular distribution circuit to which they are connected. EDTI will inform the DER provider of the requirements in these cases. DERs of less than 1,000 kW should have provision for the capability to receive EDTI trip signals and cease generation; *i.e.*, they should have provision for the

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[28] The AESO notes this implies that EDTI uses a 1:2 generation-to-load ratio in the anti-islanding assessment. This matter is further discussed in Step 3 of the screening methodology in Section 9.

installation of transfer trip. The actual implementation is not required when the DER is commissioned but may be requested by EDTI at a later date to be implemented at the DER provider's cost.

Unless the DER provider can demonstrate that there is no potential for self-excitation, transfer tripping requirements also apply to induction generators.

7.11 ENMAX Power Corporation (EPC)[29]

7.11.1 Anti-Islanding Protection

Intentional island operation is not allowed on the EPC Distribution System. Anti-islanding protection is required to meet the following protection requirements:

- Ensuring other Customers do not experience power quality problems;
- Preventing out-of-phase reclosing of the EPC Distribution System with the DER Facility; and
- Reducing the risk of safety hazard caused by unintentional island conditions.

EPC services both primary metered and secondary metered Customers. Anti-islanding schemes may involve upstream protection considerations such as multiple in-series devices like fuses, reclosers, and substation circuit breakers.

The following requirements are necessary to prevent the DER Facility interconnected to the EPC Distribution System from islanding:

1. The DER Facility must have anti-islanding protection. The DER Facility must have the following:
    - Under/overfrequency protection
    - Under/overvoltage protection
    - DER rated in aggregate ≤500 kW may utilize passive anti-islanding schemes unless otherwise dictated by EPC; and
    - DER rated in aggregate >500 kW require direct transfer trip for anti-islanding protection;
2. Upon loss of one or more phases of the EPC Distribution System, the DER Facility must automatically disconnect from the EPC Distribution System within one second; and
3. The DER Provider must provide proof to EPC that the DER Facility cannot sustain an island for longer than the one second requirement;

7.11.2 Passive Anti-Islanding Protection

1. The DER Facility rated in aggregate <500 kW applying to deliver power to the EPC Distribution System may be exempt from item requiring direct transfer trip for anti-islanding protection, but instead may be required to meet the following passive anti-islanding protection elements in replacement of direct transfer trip:
    - 81R – Rate of change of frequency; and

[29] EPC, *Distributed Energy Resource Technical Interconnection Requirements Rev. 0* (February 15, 2019).

- 78 – Vector Shift or 32R reverse reactive power;

2. All passive anti-islanding schemes must be submitted to EPC for review and approval;
3. The passive anti-islanding elements listed above must be set as sensitive as possible to reduce the non-detection zone. These settings may be adjusted with the prior approval of EPC if they are found to cause unjustified nuisance tripping;
4. If EPC does not approve a passive anti-islanding scheme for the DER Facility rated in aggregate <500kW, direct transfer trip, or maximum export (32R), or Maximum Allowable Export Capability may be considered;
5. The DER Provider must be aware of and accept the risk of using passive anti-islanding schemes described in item 1). EPC will not be responsible for damages incurred under these circumstances (e.g., out of phase reclosing, nuisance tripping);
6. The non-inverter DER Facility rated in aggregate <500kW must be prepared to receive a transfer trip signal from the EPC System Control Centre and cease power supply to the EPC Distribution System. Implementation of this capability may not be required for the original request for interconnection application but may be requested by EPC at any time at the DER Provider cost; and
7. An induction-based DER Facility not equipped with direct transfer trip must ensure that the DER is not capable of self-excitation.

7.11.3 Active Anti-Islanding Protection – Direct Transfer Trip (DTT)

A DTT signal from the upstream recloser(s) or feeder breaker(s) to the DER Facility will be required for the DER Facility rated in aggregate ≥500kW requesting parallel export operation. However, a DTT signal may not be required for an inverter-based DER Facility rated in aggregated ≥500kW meeting CSA standards, CAN/CSA 22.2-107.1 (R2011) General Use Power Supplies and CAN/CSA 22.2-257 (R2015) Interconnecting Inverter-Based Micro-Distributed Resources to Distribution Systems.

A DTT signal from an EPC substation feeder breaker(s) and/or upstream recloser(s) to the DER Facility will be required under the following conditions:

- When the net power supplied to the EPC distribution system from the DER Facility is >33% of the minimum feeder load or load downstream of a line recloser; and
- If the existing reclose interval of the upstream recloser(s) or feeder breaker(s) is <2.0 seconds.

The DER Facility must remain disconnected from the EPC Distribution System when the DTT signal is unavailable. The DTT signal must be failsafe and upon loss of DTT communications signal, a DER must be disconnected within 1 seconds of the channel failing for all the following events:

- A controlled shutdown design may be allowed upon review and approval from EPC;
- Loss of communications may activate other anti-islanding protection schemes such as directional power and overcurrent. Permissive schemes involving DTT must be submitted to EPC for review and approval; and
- The DER must remain disconnected until the DTT signal has been repaired and the EPC Control Centre has been notified that the DTT scheme is ready for operation.

In some cases, DTT is not an option due to instances such as, but not limited to upstream series protection including fuses. In these cases, maximum export and directional overcurrent may be evaluated to allow for the export of power.

8. AESO's Proposed Approach

The AESO's proposed approach for DER anti-islanding assessments is considered an enhancement to the AESO's existing anti-islanding practices, which include an assessment of DERs islanding with part of the transmission system. The AESO's proposed approach consists of a screening phase to determine the potential risk of sustained islanded operation and, if the screening identifies the potential for sustained islanded operation, a subsequent phase involving either, or both, a detailed study or the implementation of alternative mitigation measures (such as communication-based schemes).

As part of the AESO's connection process, and in carrying out its legislative duties pursuant to sections 17(h) and (m) of the *EUA*, the AESO will continue to include a requirement in future functional specifications for the TFO to coordinate with the market participant to assess the risk of anti-islanding by complying with the anti-islanding assessment outlined in this document.

The following list provides some important details regarding the AESO's proposed approach:

- Based on the penetration and geographical distribution of existing DERs in Alberta, their potential impacts on the BPS, and consistency with the AESO's connection process and markets, the AESO has determined that the anti-islanding assessment is required for DER projects that are subject to the AESO's connection process. Hence, the anti-islanding assessment is applicable to DERs with maximum authorized real power (MARP) of 5 MW or greater, or for smaller DERs (MARP less than 5 MW) that require changes in the relevant DFO's contract with the AESO for Rate STS, *Supply Transmission Service*, or Rate DTS, *Demand Transmission Service* of the ISO tariff.
- The AESO will continue to monitor the proliferation of DERs in Alberta and may in the future decrease the 5 MW threshold size, considering impacts on the BPS.
- The AESO understands that, as the system continues to evolve, (*e.g.*, transmission topology, load profile, etc.) there might be a need to re-evaluate the AESO's anti-islanding assessment approach (screening and/or detailed study) for a given DER. The AESO will perform sensitivity checks as part of the anti-islanding assessment to look at variations of load and generating profiles; however, there may still be a need to perform the anti-islanding assessment depending on the extent of changes. In such future cases, the AESO will perform such assessments and will pursue any mitigation action, if needed, in coordination with the relevant TFOs and/or DFOs.
- As indicated in Section 1, the AESO's proposed approach is intended to address DERs unintentionally islanding with the distribution system and part of the transmission system. While a similar methodology could be used for assessing islanding of DERs solely within distribution systems, this assessment is outside of the scope of this paper and will remain within the sphere of DFOs' accountability.
- The AESO's proposed approach is mainly focused on islanding scenarios where DERs become islanded with part of the transmission system and where the relevant transmission topologies are associated with N-1 and N-1-1 conditions.
    - As part of the AESO's <u>existing</u> process for coordinating planned outages, the AESO, TFOs, and affected generating facility owners consider and address the risk of unintentional islanding associated with next-contingency events on the transmission system. The mitigation measures may include:

    - Ensuring synch check relays are in place to avoid the risk of out-of-synch reclosing during trip and automated or manual closing of transmission lines[30]. In situations where a transmission line does not have a synch check relay, the auto reclosers may need to be disabled for the duration of the planned outage.
    - Operating instructions and guidance for the AESO system controllers to (a) raise situational awareness about the risk of unintentional islanding in the event that the next contingency should occur, and (b) specify required actions once the next contingency does occur and the identified unintentional island forms. Actions may include manually de-energizing the island followed by restoring the affected area to the AIES or allowing the island to operate for a short period of time and synchronizing it back to the AIES using a breaker with a synchronizer relay. These actions vary on a case-by-case basis and will depend on multiple factors during real-time operation, such as the availability of a synchronizer relay in the area, availability of the transmission system to restore the island, and the type of generation (*e.g.*, variable generation such as wind /solar, or firm generation).
  - Despite the current low probability of multiple forced outages on the AIES causing unintentional islanding under N-1-1 conditions (or beyond), the AESO expects that rapid growth of DERs in Alberta may increase the amount and complexity of these unintentional islanding events. This in turn would expose the AIES to greater reliability and safety risks, given the potentially detrimental and costly impacts of unintentional islands that are not detected and cleared in a timely manner, as previously discussed. However, as the inverter technology is evolving a the more stringent standards are being developed to ensure that the inverter based resources will have better islanding detection systems embedded in them, the AESO expects that the DERs of the future will be able to detect unintentional islands and cease to operate negating the requirement for costly communications aided transfer trip requirements. The AESO will explore the most cost effective anti-islanding solutions that could range from deployment of communication based mitigation schemes to a combination of synch check relays/auto reclose blocking and real-time operating practices.

Details of the AESO's approach are presented in the following sections.

[30] It should be noted that, in accordance with Section 502.3 of the ISO rules, *Interconnected Electric System Protection Requirements*, for all 240 kV and higher transmission line breakers, a synch check relay must be used for all three (3) pole closing. However, lower-voltage transmission lines (*e.g.*, 69/72 kV, 138/144 kV) may not necessarily be equipped with synch check relays.

9. Overview of the AESO's Proposed Screening Methodology

9.1 Assumptions

The screening methodology presented here is largely based on the Sandia screening guideline, which is intended to identify when the risk of unintentional islanding for an extended period of time (> 2 seconds) may or may not be negligible. If the risk is not negligible for the relevant islanding scenarios, a detailed technical study or additional protective measures, such as communication-based schemes, will be required. The following assumptions must hold true in order to use the AESO's Sandia-based screening methodology:

- DER is an IBR type
- DER is UL-1741 Supplement A (SA) or CSA C22.2 No. 107.1 certified, which indicates that the DER utilizes active anti-islanding method
- DER is compliant with voltage and frequency trip settings requirements set in the 2008 version of IEEE 1547 (1547.2). The voltage and frequency trip settings in this version of standard are as follows[31,32]:

Table 1—Interconnection system response to abnormal voltages

Voltage range (% of base voltage[a])	Clearing time(s)[b]
$V < 50$	0.16
$50 \le V < 88$	2.00
$110 < V < 120$	1.00
$V \ge 120$	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

[31] These settings are obtained from the 2003 version of IEEE 1547 (full version). Based on the AESO's review of available literature, the frequency and voltage trip settings did not change in the 2008 version (1547.2).

[32] The AESO understands that, compared to the 2003 version of the standard, the adoption of IEEE 1547-2018 would entail significant changes in the requirements for frequency- and voltage-related tripping and ride-through (depending on the relevant category, as outlined in IEEE 1547). Accordingly, the screening steps would need to be updated to consider different frequency and voltage settings. The AESO will continue monitoring the ongoing research in this area by Sandia and other institutions and plans to update the screening methodology as necessary.

Table 2—Interconnection system response to abnormal frequencies

DR size	Frequency range (Hz)	Clearing time(s)[a]
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< {59.8 – 57.0} (adjustable set point)	Adjustable 0.16 to 300
	< 57.0	0.16

[a]DR ≤ 30 kW, maximum clearing times; DR > 30 kW, default clearing times.

In order to use the AESO's Sandia-based methodology, it should be ensured that the frequency and voltage trip settings of the DER (and existing DERs or generation resources in an island) follow the same settings or more stringent settings.

9.2 Required Inputs and Data for Screening

The screening methodology described in Section 9.3 requires input and data from the AIES. In general, the following information is required:

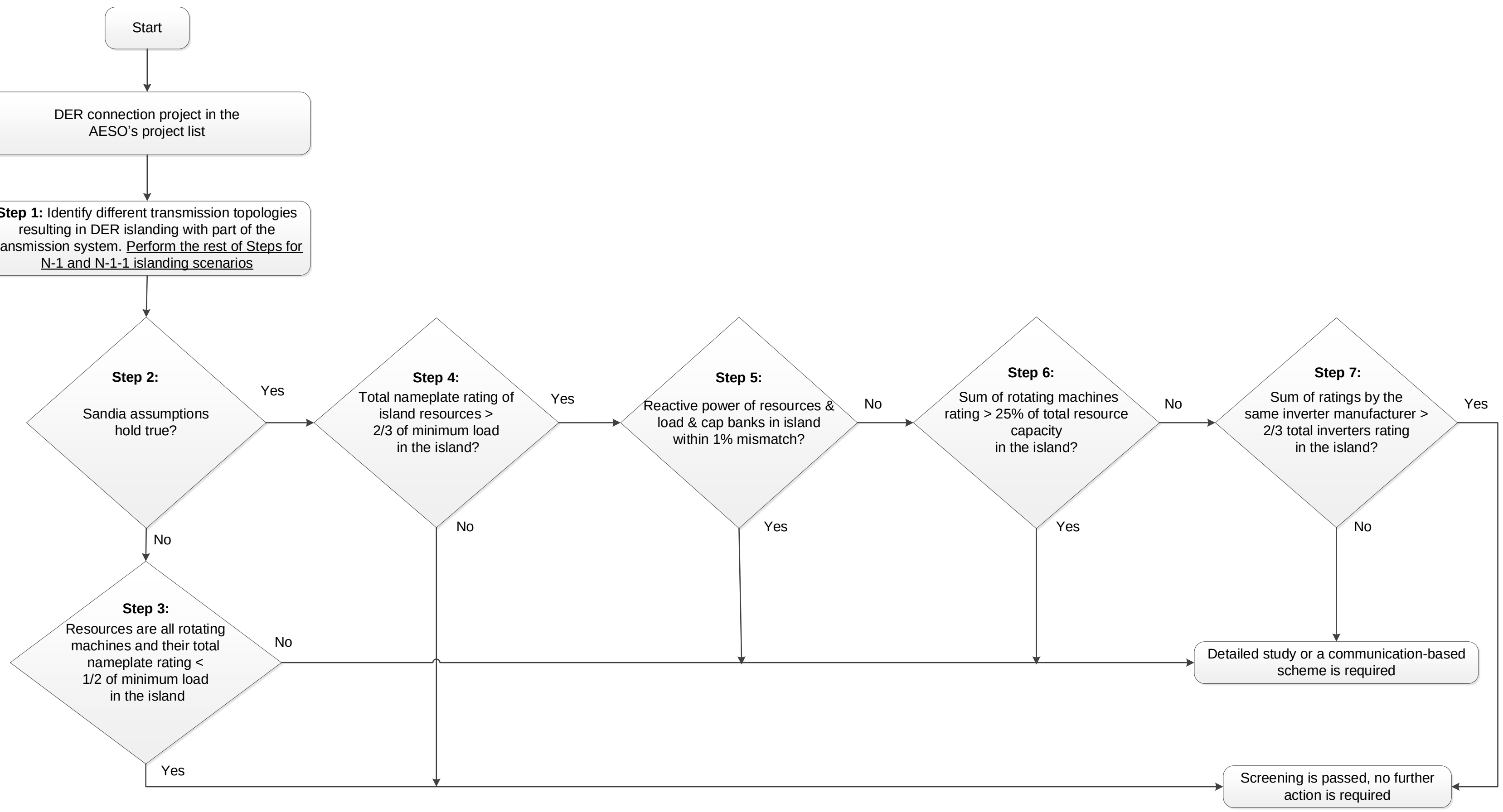
- Type of DERs, manufacturer, and nameplate rating
- Aggregated nameplate of each type of DER (based on technology and manufacturer) within potential islands is acceptable;
- Anti-islanding compliance of DER(s) to UL-1741 Supplement A (SA) or CSA C22.2 No. 107.1 indicating that the DER(s) utilize active anti-islanding method;
- Total load profile within potential islands including the loading and settings for Under-Frequency Load Shed (UFLS) feeders (if exist);
- Under voltage/Over voltage protection trip settings of DER facilities (per IEEE 1547.2 and DFOs' respective interconnection standards) and transmission-connected generation resources;
- Under Frequency/Over Frequency protection trip settings of DER facilities (per IEEE 1547 and DFOs' respective interconnection standards) and transmission-connected generation resources;
- Transmission and distribution system models, as required for an accurate assessment;
- Existing remedial action schemes (RASs) and anti-islanding schemes in the area.

9.3 Screening Methodology Steps

The AESO's screening methodology is presented below, including an illustrative flow chart. Based on the AESO's review of the DFOs' interconnection requirements outlined in Section 7, this methodology recommends that the anti-islanding requirements apply to DERs sized greater than or equal to 5 MW. Another trigger criterion for the application of the anti-islanding assessment is a significant load decrease in the vicinity of existing DER facilities. There could be a possibility of load decrease at some point in time following the connection of a DER. Hence, an anti-islanding screening assessment that was passed initially at the time of a DER connection may not pass subsequent assessments and may therefore require detailed study or other mitigation measures such as communication-based schemes.

The screening methodology is intended to serve as a high-level assessment to determine the potential islanding scenarios that could potentially sustain an islanded operation. Depending on the potential complexities associated with performing the steps in this methodology (*e.g.*, type of DER, existing DERs or other generation resources in the island, voltage and frequency trip settings, UFLS settings, etc.) engineering judgment may be required while applying this methodology. In general, it is recommended that in grey areas where there is a lack of confidence on passing the screening methodology, a detailed engineering study should be undertaken.

Note: The term nameplate rating used in the following flowchart represents the maximum MW capability of the DER or transmission-connected resource.


Start
DER connection project in the AESO's project list
Step 1: Identify different transmission topologies resulting in DER islanding with part of the transmission system. Perform the rest of Steps for N-1 and N-1-1 islanding scenarios
Step 2:
Sandia assumptions hold true?
Yes
No
Step 3:
Resources are all rotating machines and their total nameplate rating < 1/2 of minimum load in the island
No
Yes
Step 4:
Total nameplate rating of island resources > 2/3 of minimum load in the island?
Yes
No
Step 5:
Reactive power of resources & load & cap banks in island within 1% mismatch?
No
Yes
Step 6:
Sum of rotating machines rating > 25% of total resource capacity in the island?
No
Yes
Step 7:
Sum of ratings by the same inverter manufacturer > 2/3 total inverters rating in the island?
Yes
No
Detailed study or a communication-based scheme is required
Screening is passed, no further action is required

The following subsections provide details with respect to each of the steps in the screening flowchart shown above.

9.3.1 Step 1

This step identifies different transmission system topologies (N-1 and N-1-1) [33] that could result in an island of the DER with part of the transmission system. Typically, the topology screening extends to all adjacent transmission substations until a substation with more than two transmission lines is reached.[34] However, based on substation design and breaker configuration, a single contingency (such as the loss of a distribution transformer without a high-side circuit breaker) could potentially result in a loss of multiple transmission lines. Such configurations are included as part of the topology screening in this step. Transmission-connected resources (if any) in the potential islands are also identified in this step. Existing anti-islanding schemes in the area that trip the transmission-connected resources or DERs (if any), are also identified in this step for each topology; for such topologies, the relevant resources may be excluded from the rest of the screening check as they will be tripped off within a few cycles by transfer trips once the island is formed.

9.3.2 Step 2

This step verifies the assumptions in the AESO's Sandia-based methodology presented in Section 9.1. If any of the assumptions do not hold true, then the screening methodology is not passed and a detailed study or a communication-based scheme is required for the topologies identified in Step 1.

9.3.3 Step 3

Step 3 addresses a situation where the identified resources (DERs and/or transmission-connected resources) are rotating machines (induction or synchronous generation). This step and the recommended threshold are based on two references from IEEE[35,36]. If all the resources are rotating machines and the aggregated nameplate rating of these resources are less than 1/2 of the minimum load within each identified island, then the AESO considers there is no risk of sustained island operation and screening is passed for the island in question[37]. The AESO recommends examining the load duration curve (LDC) and selecting

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[33] In general, the definition of N-1 and N-1-1 contingencies follow categories B and C specified in the TPL-001-AB-0 Appendix 1. However, engineering judgment and coordination between the AESO, TFOs, DFOs, and DER owners may be required to define credible contingencies for the purpose of anti-islanding assessment.

[34] This will indicate that islanding of the DER with the transmission system will only occur if three or more transmission lines are out of service, which is not considered as a credible contingency from the screening perspective.

[35] IEEE 1547.2™-2008 IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

[36] Gish, W. B., Greuel, S., and Feero, W. E., *Ferroresonance and loading relationships for DSG installations*, IEEE Transactions on Power Delivery, Vol. PWRD-2, no. 3, pp. 953–959 (July 1987)

[37] The IEEE paper in reference suggests the 1/3 generation-to-load ratio based on simulations and field tests of induction and synchronous generation islanded with load at various ranges of reactive power and frequencies, which may not be exclusively applicable in Alberta. It was shown in the paper that as the pre-island loading approached three times the generation, no excitation condition could exist among all considered variations to support the continued operation of the island. In review of the IEEE paper and IEEE 1547.2™-2008 IEEE Application Guide, the AESO considers that the 1/3 threshold could be relaxed to 1/2 while still leaving a margin against potential variations of the minimum load in the future. As noted in the jurisdictional review in Section 5, other DFOs in Alberta such as EDTI and extra-provincial utilities such as BC Hydro also use the 1/2 threshold, while other DFOs (*e.g.*, FortisAlberta) use the 1/3 threshold.

the appropriate level of minimum loading (*e.g.*, around knee points) while applying engineering judgment. Note that if UFLS or under-voltage load shed (UVLS) feeders exist in the identified islands with the trip settings higher than DERs and transmission-connected resources (*i.e.*, UFLS or UVLS feeders trip first during frequency or voltage excursions), then further assessment, such as a detailed study, may be required to better evaluate the impacts of load loss on the island's frequency and voltage levels and to determine the effectiveness of the relevant DER's anti-islanding detection method. A sensitivity check with respect to lower loading assumptions is also recommended in this step to assess the impact of lower loading levels.

9.3.4 Step 4

This step verifies the aggregated nameplate rating of resources (DERs and/or transmission-connected resources) with respect to the minimum loading within each identified island. If the aggregated nameplate rating is less than 2/3 of the minimum island load, then the voltage in any unintentional island would drop below the 88% threshold in the IEEE 1547-2003 under-voltage trip setting, and the risk of a sustained unintentional island is negligible. In this case, the screening methodology is passed, and no further assessment is warranted. Otherwise, the next steps in the flowchart should be pursued. As described in Step 3, it is recommended that the LDC be examined and the appropriate level of minimum loading (*e.g.*, around knee points) be selected, while applying engineering judgment. If UFLS or UVLS feeders exist in the identified islands with trip settings that are more sensitive than the trip settings for the relevant DERs and transmission-connected resources (*i.e.*, which would result in the load shed feeders tripping before the generation resources), then further assessment, such as a detailed study, may be required to better evaluate the impacts of load loss on the island's frequency and voltage levels and to determine the effectiveness of the relevant DER's anti-islanding detection method. A sensitivity check with respect to lower loading assumptions is also recommended in this step to assess the impact of lower loading levels.

9.3.5 Step 5

This step verifies the reactive power mismatch between the DER and remaining load within each identified island. If the mismatch is less than 1%, then a detailed study or a communication-based scheme is required. The reactive power of load and resources in this step should be calculated based on the operating point in Step 4 where the aggregated nameplate rating of the resources exceeds 2/3 of the minimum loading in the island. In this context, the reactive power values should be calculated based on conditions where the active power values are matched or most closely matched as determined in Step 4. For example, if during Step 4 it was determined that the DER rating is 90% of the load in the identified island, then the reactive power of the load corresponding to 90% loading should be calculated in Step #5.

In addition, the reactive power contribution from transmission lines is considered in this step, which may require running simulations. In general, transmission lines have more reactance than distribution feeders so reactive power on transmission lines must not be ignored. The Sandia guideline assumes resources (DERs) operate in a constant power factor (PF) mode to determine the reactive power in this step. While constant PF is currently the default operation mode of the DERs in Alberta, this may not be the case for future DER facilities. Further, instead of operating in a constant PF mode, transmission-connected generation resources (if present in the identified island) operate in voltage control mode. This may require running simulations to calculate the MVAr output of each machine in the identified island. A sensitivity check with respect to the loading assumptions is also recommended in this step to assess impacts on the results.

9.3.6 Step 6

In Step 6, the total nameplate rating of rotating machines (DERs and/or transmission-connected resources) is evaluated against the nameplate rating of IBRs. If the sum of all rotating machines' MW rating is more than 25% of the total MW rating of IBRs in the identified island, then further study would be prudent. If the sum of all rotating machines' MW rating is less than 25% of the total IBRs, then proceed to Step 7. A rotating generator, particularly if it is a synchronous machine, could increase run-on times of IBRs because a synchronous machine may be interpreted as an intact grid by the inverter. Similarly, some of the most common anti-islanding methods used in synchronous machines are largely defeated by the much faster action taken by IBRs.

9.3.7 Step 7

Step 7 assesses the inverter manufacturers of all IBRs within an identified island. Some studies have found that mixing different types of islanding detection, or mixing inverters with the same type of islanding detection but implemented differently, leads to a degradation of islanding detection effectiveness.[38] Therefore, if no single manufacturer's product makes up at least 2/3 of the total IBR nameplate rating in the potential island, then a detailed study or a communication-based scheme may be required. If more than 2/3 of the total IBRs are built by a single manufacturer, then the risk of unintentional islanding can be considered negligible.

[38] M. Xue, F. Liu, Y. Kang, and Y. Zhang, Investigation of Active Islanding Detection Methods in Multiple Grid-Connected Converters, *6th IEEE International Power Electronics and Motion Control Conference*, 2009, pp. 2151-2154.

10. Overview of the AESO's Proposed Detailed Study Methodology

As indicated in Section 9, the need for a detailed anti-islanding study is identified if a DER does not pass the screening steps as part of the AESO's proposed anti-islanding screening methodology, which indicates that further assessment is required to ensure that there is no risk of sustained islanded operation for relevant islanding scenarios. A key objective of the detailed anti-islanding study is to determine whether the anti-islanding protection schemes located at the DER facility are capable of tripping the DER in all islanding scenarios and conditions. The local schemes could be passive methods or active methods, as described in Section 4, or a combination of both. As indicated in Section 4.1, if passive methods are used the settings (*e.g.*, frequency/voltage/RoCoF) should be compliant with the ride-through requirements specified in IEEE 1547-2018 in Alberta, which are expected to be adopted by Alberta's DFOs in the near future, and which remain subject to the applicable processes for developing ISO rules and Alberta reliability standards, if necessary. In general, and at minimum, the passive schemes should be compliant with the ride-through requirements associated with Category I for rotating machines and Category II for IBRs, as defined in IEEE 1547-2018.

If performing the anti-islanding study is not possible for whatever reason (*e.g.*, lack of appropriate models) or if the study does not demonstrate that the local schemes are effective in tripping the DER in all identified islanding scenarios, then a communication-based scheme will be required.

The following subsections provide a guide for the detailed anti-islanding study that will be performed if a DER does not pass the AESO's anti-islanding screening methodology.

10.1 Study Assumptions

10.1.1 Generation and Load profile

Various levels and combinations of generation and load profiles should be considered. A typical range of 25% to 100% with an increment of 25% for adjusting the generation and load profiles is recommended while applying engineering judgment and further modifications on case-by-case basis.

10.1.2 Study Scenario

All the identified islanding topologies in the screening methodology that did not pass the screening checks (depending on the load profile in the island, existing resources, etc.) should be included in the study.

10.2 Study Inputs, Models and Tools

The following inputs, models, and tools are required to perform the anti-islanding study:

1. The power flow base case and data, including:
   - Transmission system model
   - Distribution system model if required depending on the relative location of DER(s) in the distribution system
   - DER(s) and existing generation resources in the island (if not already included in the base case); aggregating existing DERs based on technology type, manufacturer and dynamic data may be acceptable assuming the associated dynamic data for the aggregated DERs is available.

- Load profile for each point of delivery (POD) in the potential islands[39]. Similar to what was described in Section9.3, the information on loading and setting on UFLS feeders is also required.

2. Dynamic or Electro Magnetic Transient (EMT) models:
   - In general, IBRs should be modelled and simulated in EMT platforms, such as PSCAD to properly simulate their controls and responses, particularly if the DER utilizes an active anti-islanding method[40]. The AESO recommends that the following be considered where EMT simulations are required due to the presence of IBRs in the island:
     i. The EMT model should generally follow the AESO's PSCAD Model Submission Guideline and Checklist ("PSCAD Guideline")[41] which provides that PSCAD models should include appropriate flags to indicate the activation of passive (voltage, frequency, RoCoF) and active anti-islanding methods and user interface and control to change associated settings.
     ii. Nearby generators should be represented in detail including their exciter, governor, and stabilizer controls.
     iii. A frequency-dependent transmission line model is the preferred and most accurate model to represent transmission lines. Alternatively, a Burgeon model may be used based on engineering judgment and length of transmission lines in the islands.
     iv. Any HVDC and FACT devices in the islands should be represented using detailed models in accordance with AESO's PSCAD Guideline.

   - If an EMT model is not required then a root-mean square (RMS) positive sequence platform (such as PSS/E or PSLF) should be used with a set of dynamic data to adequately represent the islands in dynamic simulations[42]. The model should generally follow the transmission modelling requirements as described Section 502.15 of the ISO rules, *Reporting Facility Modelling Data* and the related information document (ID) #2010-001R, *Facility Modelling Data and List of Electrical and Physical Parameters for Transmission System Model.* [43]

[39] This could include each substation load profile or each individual distribution transformer in each substation; depending on the islanding scenarios the load profile on each individual distribution transformer may be required in addition to the total substation load profile.

[40] Existing RMS positive sequence dynamic models (e.g. PSS/E, PSLF) do not typically represent phase lock loop dynamics and other inner loop (small time constant) controls of IBRs that often dictate the dynamic behavior and changes in control modes. As such, the RMS positive sequence models are unable to accurately represent fast controls or fault current contribution. However, this could change if an IBR could be modelled using a user-defined model or even generic model in RMS positive sequence adequately representing its behaviors during islanding conditions.

[41] *AESO PSCAD Model Submission Guideline and Checklist* (January 1, 2021), available on the AESO website.

[42] Currently, PSS/E (unlike PSLF) does not have the capability to model synchronous-based generation in the constant Power Factor (PF) mode. This software limitation should be considered as part of the detailed study and engineering judgment should be applied in terms of using another tool (e.g. PSLF) or justifying the use of PSS/E and potential impacts on dynamic simulation results. If the constant voltage control mode (the default operation of synchronous machines in PSS/E) is not believed to affect dynamic simulation results from anti-islanding study perspective, then PSS/E may be still used.

[43] Available on the AESO website.

- Fault clearing times in the transmission system elements in the area. Generic fault clearing time published in Appendix G of AESO transmission planning criteria[44] could be used as a starting point for EMT or RMS studies; actual fault clearing time may be needed based on engineering judgment.

3. Under voltage/Over voltage protection trip settings of DER facilities (per IEEE 1547 and DFO interconnection requirements) and transmission-connected generation resources in the islands (if present).
4. Under frequency/Over frequency protection trip settings of DER facilities (per IEEE 1547 and DFOs interconnection requirements) and transmission-connected generation resources in the islands (if present).
5. Existing RASs and anti-islanding schemes in the area as required, the logic and action of each scheme should be provided to facilitate including the scheme in dynamic simulations.

10.3 Study Methodology

The study should simulate the islanding conditions (N-1 and N-1-1) identified in the screening phase. Each transmission line contingency should consider the following cases:

- Three phase faults and trip on transmission system facilities considering expected fault clearing times. For transmission lines, the fault should be applied on both ends of the lines. For sensitivity analysis, unbalanced faults (*e.g.*, single line to ground, SLG) should be also applied on a few contingencies.
- Trip of the transmission system elements with no fault.

The study should demonstrate that the proposed anti-islanding method (active, passive, or a combination) is capable of successfully tripping the DER in all islanding scenarios within 2 seconds, per IEEE 1547-2018, or within the specified duration in the relevant DFO's interconnection requirements. If passive methods are used, the proposed settings (frequency, voltage, ROCOF) should meet the applicable ride-through requirements in Alberta per the applicable category defined in IEEE 1547-2018 or in the CSA C22.3 No. 9:20. A sensitivity check is also recommended to assess the impacts of results with variations in generation and load profiles; typically, the worst-case scenarios from an anti-islanding perspective are scenarios where load and generation match each other at different levels (*e.g.*, 25%, 50%, 75%, 100% of the aggregated generation resource capacity).

10.4 Study Outputs and Reports

The detailed study should provide the following deliverables:

- A draft report in Microsoft Word format
- The developed study models and supporting data

[44] Available on the AESO website at https://www.aeso.ca/assets/Uploads/Appendix-G-AESO-Transmission-Planning-Criteria-Basis-and-Assumptions-807L.pdf

10.5 Prevention of Automatic Reclosing on Unintentional Islands Out of Synchronism

Synch-check relays are considered a fail-safe approach to avoid out-of-synchronism reclosing[45] of unintentional islands should the local anti-islanding detection or communication-based schemes fail to trip the DER for islanding scenarios. Based on feedback received from the TPEG members, a number of DFOs install synch-check relays or a line reclose block to avoid the risk of out-of-synch reclosing at the feeder and distribution levels. Installation of synch-check relays at the transmission level to address the N-1 and N-1-1 topologies identified through the screening check is also an important consideration to ensure a fail-safe mechanism for the safe and reliable operation of the bulk electric system. Alternatively, redundancy in the anti-islanding scheme may avoid the need for the synch check relay installation. For example, communication-based anti-islanding schemes with appropriate redundancy in the hardware and communication links can continue to function and trip the DER in the event of an unintentional island should there be any single component failure in the scheme. In such cases, synch check relay installation may not be necessary[46]. If appropriate redundancy in design or synch-check relays for the identified N-1 and N-1-1 transmission topologies are not already in place, TFOs may wish to consider installing such relays. Alternatively, TFOs may update their operating procedures to ensure that, when the anti-islanding scheme is unavailable, reclosers without synch-check supervision on the transmission lines are disabled and operators will not manually close the breaker for the associated N-1 and N-1-1 topologies identified in the screening checks.

[45] The main risk associated with out-of-synch reclosing is the potential damage on the shaft of rotating machines in the island. This may not be the case for IBRs as there is no rotating shaft and the amount of IBR current injection to the grid is limited thus minimizing the risk of equipment damage. However, IBRs may experience control instability issue due to a sudden phase jump during out-of-synch reclosure, which may result in oscillatory behavior or even inverter trip. This risk needs to be evaluated on case-by-case basis to determine its significance in the context of unintentional islanding and decide if the installation of synch check relay is warranted.

[46] A fail-safe design in the anti-islanding scheme (*e.g.*, to address the loss of a communication link as described in Section 4.3) may be considered as another option from a design perspective to address the risk of a single component failure.

11. Roles and Accountabilities Pertaining to the AESO's Proposed Anti-islanding Assessment Approach

As indicated in Section 8, the AESO will require DER projects that follow the AESO's connection process to perform an anti-islanding assessment (*i.e.*, screening and any necessary detailed studies) as part of their connection studies. The DER owner is responsible for performing the anti-islanding assessment as part of their connection studies using the inputs and data provided by the AESO, TFOs, and DFOs. The DER owner is also responsible for any additional mitigation actions that are considered necessary. The results of the anti-islanding assessment will be shared among the AESO, TFOs, and DFOs to ensure a common understanding of risks and mitigation actions. The DER owner is expected to collaborate and consult with the AESO and TFOs and DFOs to implement any additional measures. The following RACI table illustrates accountabilities for the AESO, TFO, DFO, and DER owner pertaining to the anti-islanding assessment.

Table 1: RACI chart for anti-islanding assessments

Note: A – Accountable; **R** – Responsible; **C** – Consult; **I** – Inform

Topic	Task	AESO	TFO	DFO	DER Owner
Transmission: Islanding of DERs with part of the transmission system; applicable to DER projects that are subject to the AESO's connection process	Rule/requirements	A, R	C	C	I
	Providing required inputs to perform the screening checks and/or detailed study[47]	R	R	R	R
	Performing the screening checks and/or detailed study	C	C	C	A, R
	Acceptance of screening check and/or detailed studies	A, R	C	C	C
	Mitigation measures owned by DER owner as required (*e.g.*, implementation of local islanding detection schemes)	C	C	C	A, R

[47] The required inputs and associated accountabilities are further clarified in Table 2.

	Mitigation measures owned by TFOs/DFOs as required (transfer trips, synch check relays)[48]	C	A, R	R	R
Distribution: Islanding of DERs solely within distribution system (*i.e.*, at the distribution feeder level)	Rule/Requirements	I	I	A, R	I
	Study/Mitigation measures	I	C	C	A, R

As indicated in Sections 9.2 and 10.2, modelling data and information are required as inputs to perform the screening and study methodologies. The following table shows the accountability among the main parties involved (*i.e.*, AESO, TFOs, and DFOs) for providing the required data.

Table 2: Accountabilities for the required data for anti-islanding assessments

Data requirement	Required for	Accountable to provide	Comment
Type of DERs, manufacturer and nameplate rating (including existing DERs in the identified islands)	Anti-islanding screening check	DFO	The DFO may not have this information but the expectation is that the DFO can request and obtain the info from DER owners.
Anti-islanding compliance of DERs (including existing DERs in the identified islands)	Anti-islanding screening check	DFO	
Load profile within potential islands, load transfer within	Anti-islanding screening check and detailed study	DFO	

[48] This accountability includes associated equipment that each party owns and maintains in relation to anti-islanding mitigation. For example, in transfer trip schemes, TFOs will be accountable for implementing and maintaining breaker status monitoring at transmission substations; once an island is formed, the TFO would send a transfer trip signal to the DER facility via a communication link owned by the TFO. DER owners will be accountable for ensuring they receive the transfer trip signal at the DER facility through their communication link.

distribution system, UFLS feeders			
Voltage and frequency protection trip settings of DERs	Anti-islanding screening check and detailed study	DFO	
Voltage and frequency protection trip settings of transmission-connected resources	Anti-islanding screening check and detailed study	AESO	The AESO may not currently have such information for some of the transmission-connected generation units but can request DER owners to obtain them. Data sharing with third parties needs to be also agreed by the DER owners.
Transmission topology screening and identifying transmission-connected resources	Anti-islanding screening check and detailed study	TFO, AESO	
Existing RAS and anti-islanding schemes for T-connected resources	Anti-islanding screening check and detailed study	AESO, TFO	
Existing anti-islanding schemes for DERs	Anti-islanding screening check and detailed study	TFO, DFO	
Power flow base case(s) and dynamic models	Anti-islanding screening check and detailed study	AESO	The AESO's power flow and dynamic models include transmission system models and transmission-connected resources; DERs above certain threshold (currently >5 MW) are also included in the AESO's models. The AESO may share EMTP models of transmission connected IBRs if available. Smaller DER models will need to be provided by DFO as required.
Distribution system and DER models including dynamic or EMTP models	Anti-islanding screening check and detailed study	DFO	DER models will need to be provided by DER owners to DFO as required. The DER model is required for details study.

Fault clearing times	Anti-islanding detailed study	AESO, TFO	TFO to provide actual fault clearing times if required

12. AESO's Proposed Implementation Approach for Alberta

In recent years, the AESO has included anti-islanding requirements as part of the requisite technical assessments outlined in AESO functional specifications for generation system access service request (SASR) projects. More specifically, in 2019, when the AESO received a large number of DER-related SASRs, the AESO began explicitly articulating the requirement for an anti-islanding assessment in the functional specifications for all DER projects following the AESO's Connection or Behind-the-Fence (BTF) Processes. However, there have been variations in the manner in which the anti-islanding assessments have been performed, depending on the particular TFO, and in some cases the type of generation. Accordingly, the AESO's intent in publishing the ani-islanding guideline contained in this AESO DER Roadmap Integration Paper is to add clarity and consistency relating to existing anti-islanding practices while providing flexibility to support market participants in meeting the AESO's anti-islanding requirements in a cost-effective manner.

The AESO is planning to fully implement the anti-islanding guideline in the connection or BTF processes starting in Q4 2021.

The subsections below provide an overview of the AESO's current anti-islanding process and the expected changes to the process stemming from the full implementation of the AESO's proposed anti-islanding guideline.

12.1 Anti-Islanding Process

12.1.1 Applicability[49]

- DER projects that follow the AESO's Connection or BTF Processes.
- For a DER project requiring a functional specification at Stage 3 of the relevant AESO process, the AESO will require an anti-islanding assessment in the project's functional specification in accordance with the process outlined below.
- For DER projects that do not follow the AESO Connection Process or BTF Processes, the AESO considers the incremental risk to the system to be low at this point. However, a TFO or DFO may elect to perform an anti-islanding assessment and develop mitigation measures to address perceived risks to their respective facilities.

12.1.2 Current Process

- The anti-islanding requirement is an operational requirement stipulated in the AESO's functional specification for a given project. The functional specification is also an AESO authoritative document (AD) that establishes binding requirements on the market participant.
- The anti-islanding assessment can be conducted in Stage 3 for cost estimate purposes and/or Stage 5 depending on the project and the DER owner's needs.

[49] The applicability described here applies to both the AESO's existing process and future process (once the guideline is fully implemented) as it pertains to the anti-islanding assessment.

- The AESO requires the TFO via the functional specification to apply N-1 (one outage or one fault in Category B) and N-1-1 criteria (one outage and one fault in Category B) to identify possible islanding scenarios based on the relevant transmission system topology.
- The DER owner is required to perform an anti-islanding assessment on the potential islanding scenarios identified by the TFO.
- The AESO recommends the Sandia screening methodology to provide an option for DER owners to filter out low risk scenarios and work on a mitigation solution for high-risk scenarios. Detailed studies may be required for high-risk scenarios to verify the effectiveness of the local protection scheme. For example, passive or active anti-islanding detection methods in inverter-based resources may be able to detect the island and trip the DERs. An alternative to address the high-risk scenarios is a communication-based scheme[50].

  The following provides further details on the current anti-islanding process:

  1. Per the AESO's requirement in the functional specification, the TFO identifies all possible islanding scenarios in N-1 and N-1-1 based on transmission facility topology.
  2. The DER owner requests the existing and future generators greater than or equal to 5 MW that need to be included in the anti-islanding assessment from the AESO.
  3. The DER owner requests the loading information from the DFO and the TFO or AESO.
  4. The DER owner requests existing and future generators with maximum authorized real power (MARP) less than 5 MW that should be included in the assessment from the TFO and DFO.
  5. The AESO uses the project inclusion criteria and the in-service date of other projects in the area to identify the future generators. If the assessment is performed in Stage 3 of the relevant AESO connection process, then all relevant projects that have met the project inclusion criteria must be included in the assessment and all relevant projects that have not met the project inclusion criteria should be included as part of a sensitivity check. If the assessment is performed in Stage 5, then existing generation facility and generation projects with earlier in-service dates must be included in the assessment.
  6. The DER owner is provided with the study case by the AESO if required to understand system topology and voltage support equipment such as capacitors on transmission network and the DER owner can request confirmation from TFO as required.
  7. If required, the DER owner requests project study cases from the DFO.
  8. If a third-party consultant is performing the anti-islanding assessment on behalf of the DER owner, the DER owner provides the AESO with the name of the third-party consultant.
  9. The DER owner performs the anti-islanding assessment and authenticates the report, which may include:
     - Screening to identify low-risk and high-risk scenarios.

- Transient or EMTP type of study for high-risk scenarios if required.
- Mitigation solution for all scenarios.

10. The DER owner provides the anti-islanding assessment to the TFO, DFO, and AESO for review.
11. If the assessment indicates a communication-based scheme is required, then the AESO provides the high-level design for the communication-based scheme in a functional specification revision in consultation with the TFO, DFO, DER owner.
12. When the project nears its in-service date in Stage 5, the anti-islanding assessment and conclusions are reviewed to determine if system conditions have changed.

Note: If the project's in-service date is delayed, the assessment is reviewed and may require revision due to system condition changes.

12.1.3 Summary of key changes associated with the full implementation of the AESO-proposed anti-islanding guideline[51]

- Consistent implementation of the anti-islanding assessment, including the proposed screening and detailed study methodologies described in Sections 9 and 10.
- As previously discussed, the AESO's proposed approach will be focused primarily on islanding scenarios where DERs become islanded with part of the transmission system and where the relevant transmission topologies are associated with N-1 and N-1-1 conditions.
- On a case-by-case basis during the connection process, the AESO will consider any additional requirements that the TFO, DFO, or DER owner may wish to impose in order to mitigate the risk of unintentional islanding (*e.g.*, mitigating the risk of N-1-1 scenarios). Subject to any concerns that the AESO may have, the AESO may incorporate such additional requirements in the AESO's functional specification while also indicating which party has specified the additional requirements.

[51] In general, the same practice also is expected to be applied for anti-islanding assessment for transmission-connected generation projects.

Appendix A: TPEG Membership

Table 3: Table of TPEG Members

TPEG Member
AESO
AltaLink
ATCO
City of Lethbridge
City of Medicine Hat
City of Red Deer
ENMAX Power
EPCOR
FortisAlberta

Alberta Electric System Operator

2500, 330-5th Avenue SW
Calgary, AB T2P 0L4
Phone: 403-539-2450
www.aeso.ca

09/2022