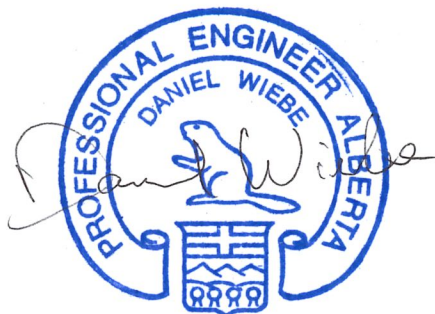




AESO Connection Requirements for Inverter-Based Resources


Connection Requirements for Inverter-Based Resources Alberta Electric System Operator

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1. Introduction

The Alberta Electric System Operator (AESO) has developed this document to set out some functional requirements for facilities that are connected with the Alberta Interconnected Electric System (AIES) and contain inverter-based resources (IBRs).

Functional specifications issued by the AESO will reference requirements within this document.

Some requirements herein address aspects of facility design or performance that are also addressed by the ISO rules. The functional requirements and ISO rules both apply in such cases.

2. Applicability

The AESO will apply the requirements herein to projects that are progressing through the connection process when it issues or amends their functional specifications. Requirements only apply to a project when its functional specification refers to them.

These requirements are intended for transmission-connected IBR facilities, but do not apply to distributed energy resources (DERs). Distribution-connected facilities are subject to distribution facility owner (DFO) connection requirements. The AESO will coordinate interconnection requirements for DERs with DFOs, as planned in its [DER Roadmap](#).

3. Definitions

The source asset to which the functional specification applies is called **the facility** herein.

The legal owner of the facility is called **the facility owner** herein.

The legal owner of the transmission facility (i.e., the substation) to which the facility is connecting is called **the transmission facility owner (the TFO)** herein.

The **point of connection (POC)** is the system bus at the interface between the facility and the AIES. For the purposes of stating requirements herein, the AESO assumes the facility has a single point of connection¹. The point of connection generally corresponds to the reference point of applicability (RPA) used in IEEE Std. 2800-2022.

Notwithstanding the AESO's Consolidated Authoritative Document Glossary (CADG), a **voltage regulating system (VRS)** is a closed-loop control system that automatically controls the reactive power resources within the facility to achieve a voltage regulating objective. An automatic voltage regulator (AVR) can be a VRS or part of a VRS. When a facility has several resources with AVRs, the VRS comprises all AVRs and any other controls that regulate reactive power.

A **frequency regulating system (FRS)** is a closed-loop control system that automatically controls real power resources within the facility to achieve a frequency regulating objective. A governor can be an FRS or part of an FRS. When a facility has several resources with governors, the FRS comprises all governors

¹ The appropriate adjustments will be made for facilities with more complex interfaces in their functional specifications.

and any other controls that interact with governors or are frequency-responsive and affect real power output, except frequency-based protections.

The **potential real power (PRP)** of a generating unit is the real power the unit is capable of producing instantaneously, considering both equipment ratings and limitations arising from availability of motive power (as indicated by wind speed, solar irradiance, or stored chemical energy). PRP is equal to **available capability** when a generating unit is not limited by motive power. The PRP of a facility is the sum of the PRP of each resource within the facility that is capable of providing real power. See AESO [ID #2012-013R](#) for further information.

4. General

4.1 Transmission System Operating Characteristics

The AESO will specify minimum and maximum anticipated short circuit current level (SCL) at the point of connection. Equipment (such as breakers) must meet or exceed the interrupting capacities specified by the AESO in the functional specification notwithstanding the anticipated range of SCL.

4.2 Environmental Conditions

The facility owner must inform the AESO of material operating restrictions based on ambient temperature.

4.2.1 Requirements for Wind Turbines

Wind turbines may cut out for self-protection. The facility owner must provide the AESO with sufficient information about cut-in and cut-out for prediction and modeling, including applicable wind speed thresholds.

4.2.2 Requirements for Solar Facilities

Solar panels may be stowed for self-protection. The facility owner must provide the AESO with sufficient information about stowing systems for prediction and modeling, including:

- The potential causes of stowing events, such as wind speed, snow shedding, or hail.
- Parameters and settings controlling the behavior of the stowing system for each scenario, such as the wind speed at which stowing occurs and the amount of time required to move the panels.
- The expected reduction in facility output when stowing occurs.

4.3 Short Circuit Level

IBR units within the facility should be designed to operate reliably when the SCL at the point of connection is between the minimum and maximum values specified in the functional specification. The facility must not contain any IBR unit with a short circuit ratio (SCR) design limit that the facility is anticipated to violate, considering the minimum SCL specified by the AESO.

4.4 Equipment Unavailability

The functional requirements for the facility are based on an operating scenario where all equipment within the facility is in service. When equipment within the facility is not in service, the facility is permitted to have reduced capabilities and performance only in proportion to the reduction in maximum real power output caused by the equipment outages, or as otherwise permitted by the AESO.

5. Reactive Power Capability

5.1 General Requirements

The facility must be capable of providing any amount of reactive power between Q_{MIN} and Q_{MAX} , where Q_{MIN} and Q_{MAX} are functions of real power output and voltage as defined herein. Reactive power output is as measured at the **point of connection**. The facility must provide dynamic reactive power across the entire required range (Q_{MIN}, Q_{MAX}). Reactive power is dynamic when it is provided by dynamic sources with output that can vary continuously between their individual limits under the control of a **voltage regulating system**.

Devices that use power electronics to provide continuously variable reactive power, such as an inverter, a static var compensator (SVC), a static synchronous compensator (STATCOM), or a doubly fed induction generator (DFIG), are considered dynamic reactive power sources.

A synchronous machine is considered a dynamic reactive power source if and only if its excitation is automatically controlled to meet the facility's voltage regulating objectives.

An electronically controlled discrete reactive element, such as a thyristor-switched capacitor, is considered dynamic if and only if its switching is coordinated with variable reactive power sources so that the reactive power output of the facility as a whole is continuously variable.

A mechanically switched reactive element, such as a shunt capacitor or reactor, is not considered dynamic. However, it may be used to compensate for reactive power losses within the facility so that the dynamic output of the facility has the required range.

Reactive elements that are not dynamic must be automatically controlled and coordinated with dynamic reactive power sources, with the objective of ensuring the facility has the required range of dynamic reactive power.

When a transformer tap changer is under automatic control, the control logic must be coordinated with dynamic reactive power sources, mechanically switched elements that are under automatic control, and other transformers, with the goals of ensuring the facility can provide dynamic reactive power across the required range and effectively meet its voltage regulating objectives.

The facility must provide reactive power support when the primary energy source is available, not available, and during the transition between these states. Generating units within the facility must have the capability to remain in service when the facility is not producing or consuming active power.

The reactive power capability requirements established in this section are steady state requirements that apply for an indefinite period of time. Additionally, the facility must be able to provide reactive power dynamically in accordance with the requirements for response to abnormal system conditions, even when the reactive power that is provided exceeds the steady state requirements.

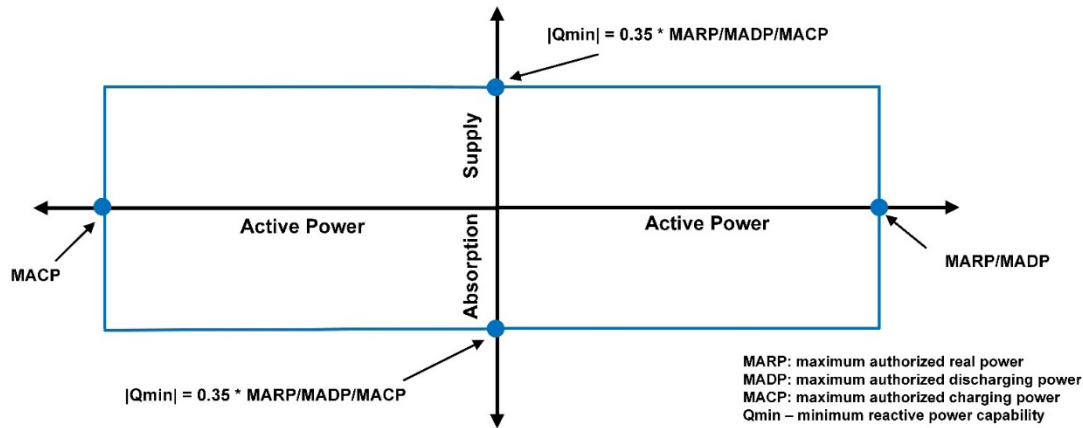
Notwithstanding the minimum reactive power capability requirements, generating units and other reactive power resources within the facility must be configured to provide reactive power up to their design limits, except as needed to ensure the facility operates safely, reliably, and within its ratings. Reactive power must not be limited for the sole purpose of ensuring the facility does not exceed the minimum requirements.

5.1.1 Requirements for a Facility with Energy Storage

For the purposes of reactive power capability, $Q_{CAP} = 0.35 \times \max(|MARP|, |MACP|)$.

When the voltage at the **point of connection** is 1.02 p.u., the reactive power capability requirement is $Q_{MAX} = +Q_{CAP}$ and $Q_{MIN} = -Q_{CAP}$, for any value of real power output between MARP and MACP (inclusive), when the facility is in-service. This requirement is illustrated in Figure 1.

Figure 1: Reactive Power Capability for a Facility with Storage

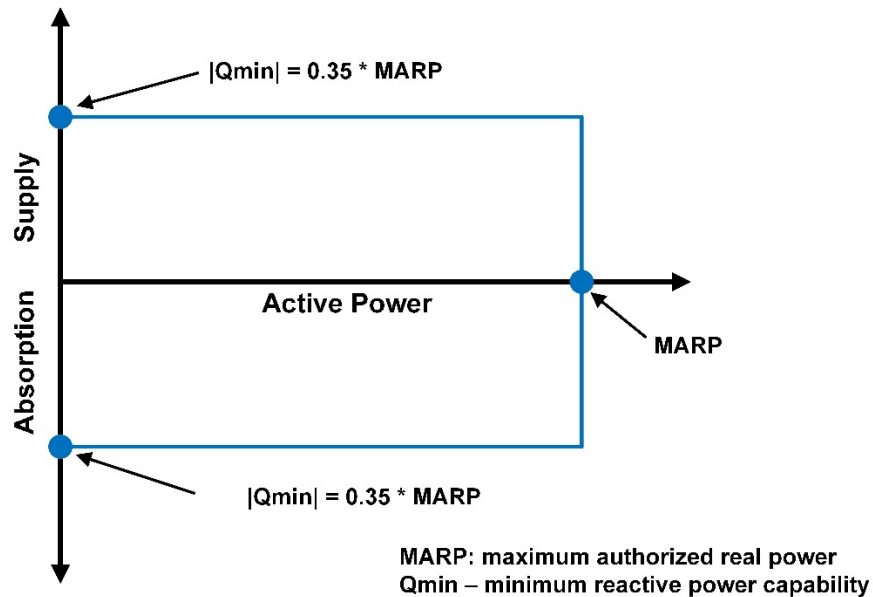


5.1.2 Requirements for an Inverter-Based Generator Facility

For the purposes of reactive power capability, $Q_{CAP} = 0.35 \times |MARP|$.

When the voltage at the **point of connection** is 1.02 p.u., the reactive power capability requirement is $Q_{MAX} = +Q_{CAP}$ and $Q_{MIN} = -Q_{CAP}$, for any value of real power output between 0 and MARP (inclusive), when the facility is in-service. This requirement is illustrated in Figure 2.

Figure 2: Reactive Power Capability for an Inverter-Based Generator Facility



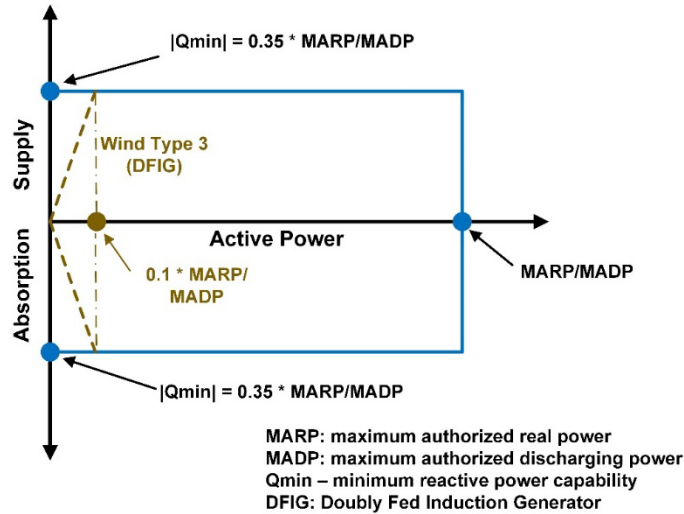
5.1.3 Requirements for a Facility with DFIG Turbines

Let $Q_{CAP}(P)$ be a function of real power output P , defined as:

$$Q_{CAP} = \begin{cases} 3.5 \times P & P \leq 0.1 \times MARP \\ 0.35 \times MARP & P > 0.1 \times MARP \end{cases}$$

When the voltage at the **point of connection** is 1.02 p.u., the reactive power capability requirement is $Q_{MAX} = +Q_{CAP}$ and $Q_{MIN} = -Q_{CAP}$, for any value of real power output between 0 and MARP (inclusive), when the facility is in-service. This requirement is illustrated in Figure 3.

Figure 3: Reactive Power Capability for DFIG-Based Wind Turbine Facilities



5.2 Off-Nominal Voltage Requirements

The voltage dependence of the reactive power capability requirement is based on the per-unit phase-to-phase root mean square voltage, v , at the **point of connection**.

5.2.1 Standard Requirements

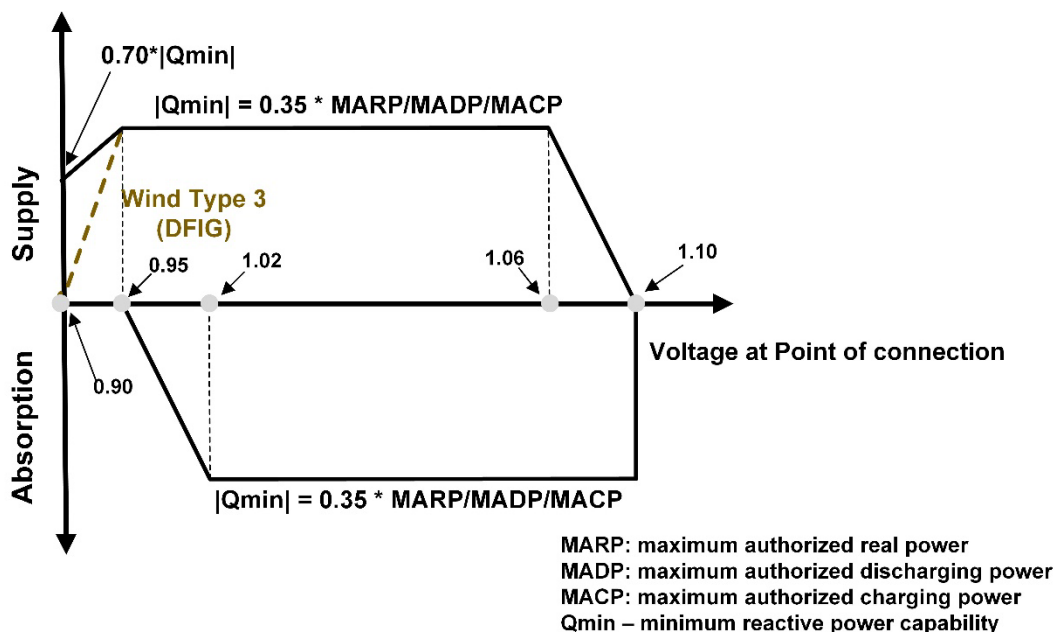
The reactive power capability requirements are:

$$Q_{MAX}(v) = \begin{cases} (0.7 + 6 \times (v - 0.90)) \times Q_{MAX}(1.02) & 0.90 \leq v < 0.95 \\ Q_{MAX}(1.02) & 0.95 \leq v < 1.06 \\ (1 - 25 \times (v - 1.06)) \times Q_{MAX}(1.02) & 1.06 \leq v \leq 1.10 \\ 0 & v < 0.90; v > 1.10 \end{cases}$$

$$Q_{MIN}(v) = \begin{cases} \left(\frac{100}{7} \times (v - 0.95)\right) \times Q_{MIN}(1.02) & 0.95 \leq v < 1.02 \\ Q_{MIN}(1.02) & 1.02 \leq v \leq 1.10 \\ 0 & v < 0.95; v > 1.10 \end{cases}$$

These requirements are illustrated in Figure 4.

Figure 4: Reactive Power Capability Requirement for Off-Nominal Voltage



5.2.2 Requirements for a Facility with DFIG Turbines

The reactive power capability requirements are:

$$Q_{MAX}(v) = \begin{cases} (20 \times (v - 0.95)) \times Q_{MAX}(1.02) & 0.90 \leq v < 0.95 \\ Q_{MAX}(1.02) & 0.95 \leq v < 1.06 \\ (1 - 25 \times (v - 1.06)) \times Q_{MAX}(1.02) & 1.06 \leq v \leq 1.10 \\ 0 & v < 0.90; v > 1.10 \end{cases}$$

$$Q_{MIN}(v) = \begin{cases} \left(\frac{100}{7} \times (v - 0.95)\right) \times Q_{MIN}(1.02) & 0.95 \leq v < 1.02 \\ Q_{MIN}(1.02) & 1.02 \leq v \leq 1.10 \\ 0 & v < 0.95; v > 1.10 \end{cases}$$

6. Voltage Regulation

The facility must implement voltage regulation in accordance with the ISO rules.

The full range of dynamic reactive power the facility can produce must be under the control of a **voltage regulating system**. The VRS must provide the following control modes:

- Voltage set-point control mode, wherein the VRS dynamically adjusts the reactive power output of the facility, to maintain voltage at the point of control equal to the set-point. The voltage set point is operator configurable.
- Power factor control mode, wherein the VRS maintains reactive power output in proportion to real power. The proportion of reactive to real power, i.e., the power factor, is operator configurable.
- Reactive power set-point control mode, wherein the VRS maintains fixed reactive power output as measured at the point of connection, regardless of voltage or the facility's real power output.

The VRS control mode and the main settings for each control mode must be capable of remote adjustment. The facility operator must be capable of responding to instructions to change the VRS configuration, including the voltage set-point, within 15 minutes.

The reactive power tolerance for power factor and reactive power set-point control modes is $\pm 1.75\%$ of MARP. The voltage tolerance for voltage set-point control mode is ± 0.005 p.u.

Notwithstanding ARS VAR-002-AB-4.1 requirement R1 (b), the VRS must be operational except during forced outages of relevant equipment or planned maintenance outages or as otherwise authorized by the AESO. The facility owner shall make reasonable efforts to keep the VRS and reactive power resources in good repair and return equipment to service expeditiously when forced outages occur.

The VRS must be operated in voltage set-point control mode except when the AESO directs or authorizes other modes of operation. When the VRS is in voltage set-point mode it must use all available dynamic reactive power resources within the facility to maintain the voltage set-point. The VRS must measure voltage at either the collector bus or **point of connection** for the purpose of voltage set-point regulation.

The VRS must use reactive current compensation control when in voltage set-point control mode.

The droop shall be established using (the inverse of) 75% of the total admittance between the **point of connection** and the collector bus as the reactance to compensate for. For clarity, the point of control is closer to the point of connection than the collector bus.

When the voltage at the **point of connection** is within the continuous operation region, and while regulating voltage at the control point, the VRS may limit reactive power as needed to prevent IBR units from tripping based on steady state collector bus voltage. Reactive power must be limited no more than necessary to prevent trips. Coordinated control systems² should respond by taking any actions available to bring collector bus voltage back within dynamic control.

Such actions may include:

- Changing the tap setting(s) of the main power transformer(s).
- Switching capacitors or reactors.
- Providing an operator alarm.

In the context of the voltage regulating system's step response:

- Reaction time is the time from initiation of the step response until the first consequent measurable change in reactive power.
- Rise time is the time from initiation of the step response until the first time when reactive power output reaches 95% of its final value.
- Step response time is the time from initiation of the step response until the first time the reactive power output will remain within 5% of the steady state value.
- Damping ratio is as defined in IEEE Std. 2800-2022, Annex L.

² Such as a power plant controller.

If possible, the step response of the voltage regulating system shall exhibit:

- Reaction time less than 0.2 [s].
- Rise time between 0.1 [s] and 1 [s].
- Step response time less than 30 [s].
- Damping ratio greater than 0.3.

Notwithstanding the step response requirements, the facility owner should prioritize a stable, damped response in all operating conditions over response time, and seek variances to rise time and step response time requirements as needed to achieve stability in foreseeable operating conditions.

7. Frequency Response

7.1 Notation

The following notation is used in this section.

Symbol	Units	Definition
db_a	Hz	Deadband, above nominal frequency
db_b	Hz	Deadband, below nominal frequency
R_a	p.u.	Frequency droop setting, above nominal frequency
R_b	p.u.	Frequency droop setting, below nominal frequency
f_{nom}	Hz	The nominal frequency
P	MW	The real power output of the facility, measured at the point(s) where MARP and/or MACP are defined
P_A	MW	The facility's potential real power
P_{MIN}	MW	The minimum achievable power output, which is $- MACP $ for a facility with an energy storage resource; or the facility's minimum stable power output or zero, whichever is larger, for any other facility
P_{MAX}	MW	The facility's maximum authorized real power (MARP)
P_{pre}	MW	In the context of a frequency excursion, the power output of the facility at the instant in time when system frequency exits the interval $(f_{nom} - db_b, f_{nom} + db_a)$
P_{PFR}	MW	Incremental power output due to primary frequency response
P_{BASE}	MW	Base value for frequency regulating system response

7.2 Primary Frequency Response

The facility must have a **frequency regulating system** that is responsive in both under-frequency and over-frequency conditions. The FRS must use fixed droop control and a non-step deadband to provide primary frequency response. Deadband and droop may be, but are not required to be, asymmetrical.

The facility owner must choose frequency regulation settings within the bounds indicated in Table 1.

Table 1: Permissible FRS Settings

Parameter	Minimum	Maximum
db_a	0.015 Hz	0.036 Hz
db_b	0.015 Hz	0.036 Hz
R_a	0.03 (3%)	0.05 (5%)
R_b	0.03 (3%)	0.05 (5%)

The fixed droop settings R_a and R_b are the percentage changes in frequency (exclusive of the deadband) that result in a 1.0 p.u. change in real power output when the frequency is above or below the deadband, respectively. For the purposes of calculating the per unit change in output, the base value is $P_{BASE} = \max\{P_{MAX}, |P_{MIN}|\}$.

The expected incremental power output due to primary frequency response (subject to limitations in the real power capability of the facility) is:

$$P_{PFR}(f) = \begin{cases} -\frac{(f - db_a) - f_{nom}}{f_{nom}} \times \frac{P_{BASE}}{R_a} & f > f_{nom} + db_a \\ 0 & f_{nom} - db_b < f < f_{nom} + db_a \\ \frac{f_{nom} - (f + db_b)}{f_{nom}} \times \frac{P_{BASE}}{R_b} & f < f_{nom} - db_b \end{cases}$$

When the system reaches an off-nominal settling frequency after a disturbance, the expected real power output of the facility is:

$$P_{expected}(f) = \max(\min(P_A, P_{pre} + P_{PFR}), P_{MIN})$$

where P_{pre} is the pre-disturbance power output.

The nominal frequency is $f_{nom} = 60$ [Hz].

7.2.1 Requirements for a Generating Facility

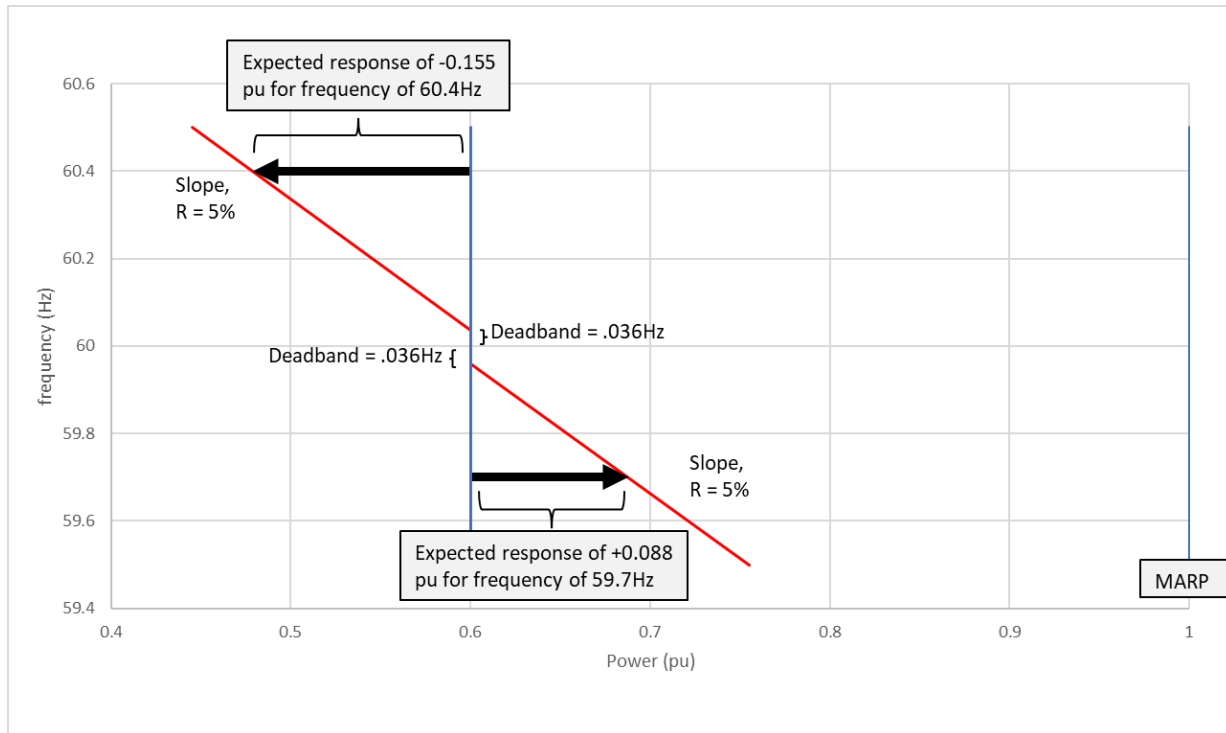
As an example of the expected frequency response, consider a hypothetical facility with $MARP = 100$ [MW], $R_a = R_b = 0.05$, $db_a = db_b = 0.036$ [Hz]. Suppose a frequency excursion occurs when $P_{pre} = 60$ [MW], the PRP is $P_A = 90$ [MW], and the minimum stable generation is $P_{MIN} = 40$ [MW].

- (a) For an under-frequency excursion where the settling frequency is 59.7 [Hz], the expected response is $P_{PFR} = \left(\frac{60 - 59.7 - 0.036}{60}\right) \times \frac{100 \text{ MW}}{0.05} = 8.8$ [MW] = 0.088 pu; and the expected output is $\max(\min(90, 60 + 8.8), 40) = 68.8$ [MW].

- (b) For an over-frequency excursion where the settling frequency is 60.4 [Hz], the expected response is $P_{PFR} = -\left(\frac{60.4-0.036-60}{60}\right) \times \frac{100 \text{ MW}}{0.05} = -12.1 \text{ [MW]} = -0.121 \text{ pu}$; and the expected output is $\max(\min(90, 60 - 12.1), 40) = 47.9 \text{ [MW]}$.

These frequency response scenarios are illustrated in Figure 5.

Figure 5: Generator Frequency Response Example



7.2.2 Requirements for an Inverter-Based Energy Storage Resource

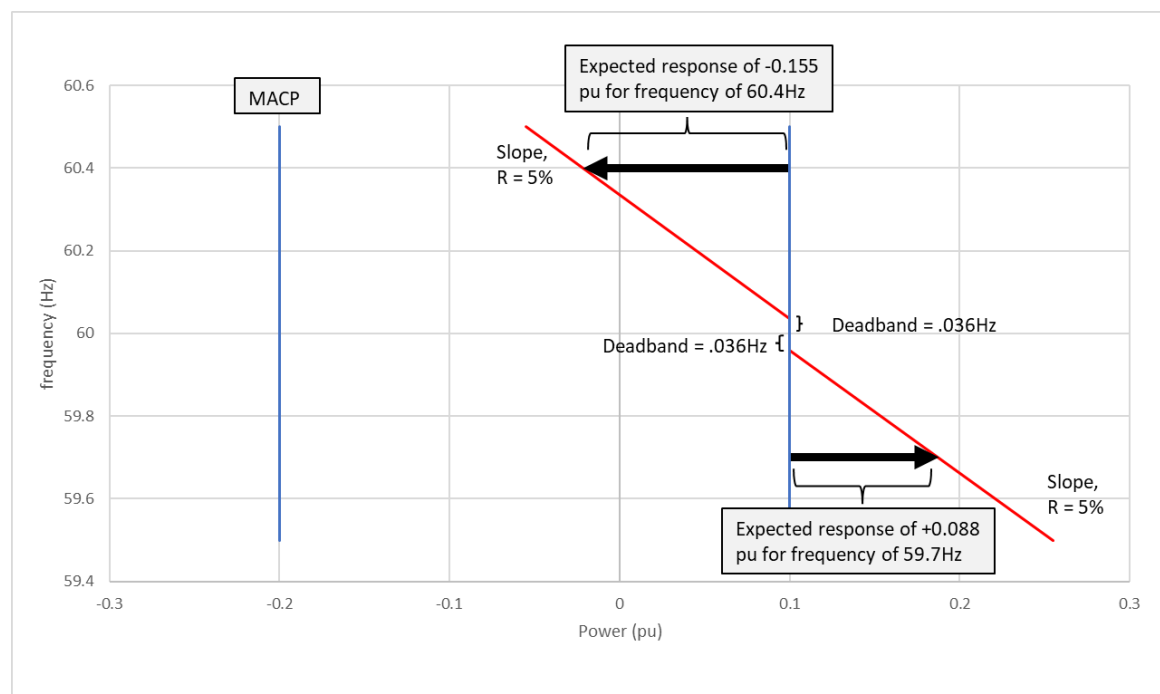
The facility must be capable of frequency response when producing or consuming active power. The facility must be capable of continuously adjusting real power output between P_{MIN} and P_{MAX} under control of the FRS, including when the provision of frequency response requires an energy storage resource to transition between producing and consuming active power.

As an example of the expected frequency response, consider a hypothetical facility with $MARP = 50 \text{ [MW]}$, $MACP = 10 \text{ [MW]}$, $R_a = R_b = 0.05$, and $db_a = db_b = 0.036 \text{ [Hz]}$. (For this facility, $P_{BASE} = 50 \text{ [MW]}$). Suppose a frequency excursion occurs when $P_{pre} = 5 \text{ [MW]}$, and the PRP is $P_A = 50 \text{ [MW]}$.

- (a) For an under-frequency excursion where the settling frequency is 59.7 [Hz], the expected response is $P_{PFR} = \left(\frac{60-59.7-0.036}{60}\right) \times \frac{50 \text{ MW}}{0.05} = 4.4 \text{ [MW]} = 0.088 \text{ pu}$; and the expected output is $\max(\min(50, 5 + 4.4), -10) = 9.4 \text{ [MW]}$.
- (b) For an over-frequency excursion where the settling frequency is 60.4 [Hz], the expected response is $P_{PFR} = -\left(\frac{60.4-0.036-60}{60}\right) \times \frac{50 \text{ MW}}{0.05} = -6.07 \text{ [MW]} = -0.121 \text{ pu}$; and the expected output is $\max(\min(50, 5 - 6.07), -10) = -1.07 \text{ [MW]}$.

These frequency response scenarios are illustrated in Figure 6.

Figure 6: Energy Storage Frequency Response Example



7.3 Dynamic Response

In the context of the frequency regulating system's step response:

- Reaction time is the time from initiation of the step response until the first consequent measurable change in real power.
- Rise time is the time required, following initiation of the step response, for the facility's real power output to go from 10% to 90% of its final value.
- The settling band is a range of real power output that contains the final value.
- Settling time is the time from initiation of the step response until the first time the facility's real power output will remain within the settling band.
- Damping ratio is as defined in IEEE Std. 2800-2022, Annex L.

The facility owner must configure and operate the frequency regulating system so that the real power output of the facility has a frequency step response that meets the constraints in Table 2. (The real power step size is determined by $P_{PFR}(f)$ in Section 7.2).

Notwithstanding the step response requirements, the facility is not required to exceed its ramping capability. If the facility is unable to meet the step response requirements because its ramping capability is insufficient, then the ramp rate available to the FRS shall be as high as technically feasible, and the facility owner shall inform the AESO of the achievable frequency step response characteristic and the applicable ramp rate.

Table 2: Frequency Step Response Constraints

Parameter	Units	Target	Minimum	Maximum
Reaction time	sec.	0.5	0.2	1.0
Rise time	sec.	4.0	2.0	20
Settling time	sec.	10	10	30
Damping ratio	unitless	0.3	0.2	1.0
Settling band	% of P_{PFR}	2.5%	1%	5%

The frequency response shall be stable, and oscillations shall be positively damped with a damping ratio of 0.2 or higher. Stable and damped response shall take precedence over rise time and settling time, i.e., the facility owner should extend rise time or settling time as needed to ensure a stable and damped response.

7.4 Primary Frequency Response in Operation

During a frequency disturbance where the system frequency is outside the deadband but within the continuous or mandatory operating regions, the facility must dynamically adjust its active power output as a function of frequency, in accordance with the incremental output requirement in Section 7.2 and the step response requirement in Section 7.3.

When an under-frequency excursion occurs, the facility is required to increase its real power output under control of its FRS if the facility is operating at less than its potential real power and no transmission constraints apply.

The facility's total active power output may temporarily exceed the facility's MARP or MACP for the purpose of providing temporary dynamic frequency response; but in accordance with ISO Rule 503.2, the facility must not be dispatched beyond MARP or MACP.

7.4.1 Performance Requirement

Several factors affect the operational response of a facility to a frequency disturbance. As a practical means for determining whether a facility is in compliance with Section 7.2 and Section 7.3, the AESO will use a time-averaged performance metric indicative of the per-unit primary frequency response (PUPFR) of the facility.

PUPFR is calculated for each frequency disturbance as the ratio of the adjusted actual primary frequency response (*Actual PFR*) to the expected primary frequency response (*Expected PFR*) of the facility and is limited to a range of $0.0 \leq PUPFR \leq 2.0$:

$$PUPFR = \begin{cases} \min\left(2.0, \frac{Actual\ PFR}{Expected\ PFR}\right), & \frac{Actual\ PFR}{Expected\ PFR} > 0.0 \\ 0.0, & \frac{Actual\ PFR}{Expected\ PFR} \leq 0.0 \end{cases}$$

Actual PFR is the difference between pre-disturbance and post-disturbance average measured power, with an adjustment for the pre-disturbance ramp rate. A ramp adjustment is used to account for ramping in the minute prior to the frequency excursion:

$$\text{Actual PFR} = P_{\text{post-disturbance}} - P_{\text{pre-disturbance}} - \text{Ramp}$$

The calculations depend on discrete time series measurements where each measurement has an integer index. The AESO uses the notation $\kappa(t)$ to indicate the index of the sample closest in time to t for the purpose of discrete summation, and $t(k)$ to indicate the time in seconds at the beginning of sample k .

For the purposes of calculating Actual PFR, the actual pre- and post-disturbance power output values are calculated as follows:

$$P_{\text{post-disturbance}} = \frac{1}{k_n - k_0} \sum_{k_0=\kappa(T+20)}^{k_n=\kappa(T+52)} P_k$$

$$P_{\text{pre-disturbance}} = \frac{1}{k_n - k_0} \sum_{k_0=\kappa(T-16)}^{k_n=\kappa(T-2)} P_k$$

The ramp adjustment, $\text{Ramp} = (P_{\kappa(T-4)} - P_{\kappa(T-60)}) \times \frac{52-20}{60-4}$, is the change in power output that would occur if the facility maintained the pre-disturbance ramp rate in the post-disturbance power measurement period.

Expected PFR is calculated as in Section 7.2 using the average values of pre- and post-disturbance frequency over the same measurement periods as Actual PFR:

$$\text{Expected PFR} = \text{Expected } P_{\text{post-disturbance}} - \text{Expected } P_{\text{pre-disturbance}}$$

For the purpose of calculating Expected PFR, the expected pre- and post-disturbance power output values are calculated using the definition of $P_{\text{expected}}(f)$ provided in Section 7.2 as follows:

$$\text{Expected } P_{\text{post-disturbance}} = \frac{1}{k_n - k_0} \sum_{k_0=\kappa(T+20)}^{k_n=\kappa(T+52)} P_{\text{expected}}(f_k)$$

$$\text{Expected } P_{\text{pre-disturbance}} = \frac{1}{k_n - k_0} \sum_{k_0=\kappa(T-16)}^{k_n=\kappa(T-2)} P_{\text{expected}}(f_k)$$

The AESO may adjust expected PFR when evaluating performance in some cases³.

The facility must achieve a minimum 12-month rolling average PUPFR of 0.75 based on frequency excursions chosen by the AESO, except possibly when fewer than 8 sufficiently large frequency excursions exist in the evaluation window.

7.4.2 Requirements for a Generator

When an over-frequency excursion occurs, the facility is required to decrease its real power output, under control of its FRS, if and only if its output is greater than its minimum stable generation.

³ Such as when some resources within the facility are not available, or when ramping interacts with frequency response in a way that violates the AESO's assumptions.

7.4.3 Requirements for a Facility with Energy Storage

The facility may, but is not required to, inhibit frequency response when its real power output is ≤ 0 . By doing so, it may become ineligible to provide some ancillary services.

Discontinuities or delays when switching between absorbing and injecting real power shall not prevent the facility from meeting the dynamic frequency response requirements.

7.5 Fast Frequency Response Capability

7.5.1 Requirements for a Facility with Wind Turbines

Each wind turbine generator within the facility must implement a form of FFR commonly called “synthetic inertia”, as further specified below.

The facility shall have a synthetic inertia response that can be enabled or disabled. The response shall be disabled, except when the AESO directs the facility owner to enable it. The response must have a configurable, asymmetric deadband relative to nominal frequency that can range from 0 to 0.1 [Hz] (under-frequency) and 0 to 1.0 [Hz] (over-frequency). The response is activated when: it is enabled; system frequency exits the deadband; and the wind turbine generator (WTG) is not already providing a response or within its energy recovery period.

When a response is activated, the WTG must inject incremental real power that is at least 5% of the WTG rated power at peak response, provided the WTG output is greater than 25% of its rated power, and provided the response would not cause the WTG to exceed any applicable ratings. The incremental real power injection⁴ shall persist at its peak value for 5 to 10 [s], with a rise time of 1.5 [s] or less. The WTG may have a reduced response when its output is less than 25% of rated power. The WTG is not required to reserve potential real power output so it can provide a synthetic inertia response.

Each synthetic inertia response is followed by an energy recovery period. The WTG must limit its decrease in power output for energy recovery to 20% or less of its pre-disturbance active power output. The energy recovery period should be reasonably extended in time to limit the decrease in power output.

A WTG must be capable of responding again two minutes after an energy recovery period. A WTG is not required to provide primary frequency response during an energy recovery period.

The facility owner must provide the AESO with sufficient information to model the potential synthetic inertial response of each turbine, including a list of configurable parameters, their allowable values, and documentation relating the parameters to the duration and shape of the real power response and recovery period in the full range of operating conditions.

8. Response to Abnormal System Conditions

This section outlines the performance requirements that shall be met by the facility when abnormal system conditions affect the facility.

The requirements established in this section refer to Section 7 of IEEE Std. 2800-2022.

⁴ Real power is injected into the system when frequency is below nominal and outside the deadband.

The applicable voltage in this section is the voltage at the point of connection. It corresponds to the applicable voltage in IEEE Std. 2800-2022.

8.1 Voltage Ride-Through Requirements

8.1.1 General Requirements

Unless stated otherwise, the applicable voltage is the voltage at the point of connection, and per unit voltages are based on the nominal voltage of the system bus at the POC.

The facility shall be designed to ride through voltage disturbances of the magnitude and duration specified in Table 3, and provide responses as specified in Table 3. Generating units within the facility must not trip due to self-protection for disturbances that originate outside the facility when the voltage at the point of connection remains within the defined bounds, except as permitted herein.

Table 3: Response to Voltage Disturbances

Applicable voltage, V (p.u.)	Operation Region/response	Minimum ride-through time (s) ⁵
$V > 1.25$	May ride through or may trip	NA
$V > 1.15$	Mandatory operation	1.0
$V > 1.10$	Mandatory operation	1800
$0.90 \leq V \leq 1.10$	Continuous operation	Infinite
$V < 0.90$	Mandatory operation	3.0
$V < 0.70$	Mandatory operation	2.5
$V < 0.50$	Mandatory operation	1.2
$V < 0.25$	Mandatory operation	0.16
$V < 0.10$	Permissive operation	0.16

8.1.2 Voltage Disturbances Within the Continuous Operation Region

For voltage disturbances wherein the applicable voltage remains within the continuous operation region, the facility must remain connected and maintain its real power output at the pre-disturbance value or the PRP, whichever is less, subject to the following exceptions:

- The facility may trip when needed for self-protection based on negative sequence voltage in accordance with the restrictions established in IEEE Std. 2800-2022, Section 7.2.2.2.
- If the facility cannot provide both real and reactive power due to current or apparent power limits when the voltage falls below 0.95, then reactive power shall be prioritized. Real power may fluctuate as needed to regulate voltage while prioritizing reactive power.

⁵ The specified minimum duration is cumulative over one or multiple disturbances within a 10 second window, unless the applicable voltage is greater than 1.1 per unit and less than 1.15 per unit, in which case the duration is cumulative over one or multiple disturbances within a 3600 second window.

8.1.3 Ride-Through Within the Mandatory or Permissive Operation Regions

8.1.3.1 Low and High Voltage Ride-Through Capability and Performance

A ride-through event occurs when the applicable voltage goes outside of the continuous operation region. A ride-through event may cause units within the facility to enter ride-through mode.

Each generating unit within the facility shall be capable of prioritizing real or reactive current during high- or low-voltage ride-through events. The facility shall prioritize reactive current in ride-through mode except when mutually agreed between the facility owner and the AESO.

The plant controller shall not interfere with or prevent the controls of generating units or other dynamic reactive power sources within the facility from meeting ride-through requirements.

For a ride-through event where the applicable voltage is in the mandatory operation region, the facility:

- Must remain connected.
- Must operate in ride-through mode and inject current in accordance with Section 8.1.3.2 when not in continuous operation mode .

For a ride-through event where the applicable voltage is in the permissive operation region, but outside the mandatory operation region, the facility:

- Must remain connected.
- May operate in ride-through mode and inject current in accordance with Section 8.1.3.2, or may operate in current blocking mode. Positively damped current oscillations are permissible.
- Must resume current exchange within five cycles of the applicable voltage returning to the continuous or mandatory operation region when in current blocking mode.

8.1.3.2 Current Injection During Ride-Through Mode

When a generating unit is in ride-through mode, it must maintain automatic voltage regulation and be capable of injecting current up to its maximum current rating.

Each generating unit shall be capable of injecting both positive and negative sequence currents depending on the magnitude of voltage deviation caused by a balanced or unbalanced fault or voltage excursion.

A generating unit's response to voltage disturbances in ride-through mode shall be configurable, including the proportionality between voltage deviation and current, phase angle relationship, timing, and priority for positive and negative sequence current injections. Each generating unit shall be capable of applying different settings to low-voltage and high-voltage ride-through events.

The proportionality between the voltage deviation (p.u.) at the terminals of an IBR unit and the resulting incremental current injection (p.u.), in ride-through mode, is generally known as the K factor. By default, generating units shall be configured with $K = 2$. The facility owner shall perform EMT studies (as required in Section 12) to test the suitability of the K factor and other fault response settings, and adjust the settings as needed to ensure the facility has an acceptable response⁶.

⁶ In particular, the facility's fault response should not cause unacceptable transient over-voltages, and fault response settings should be adjusted to reduce the risk.

Real or reactive current injection capability may vary depending on voltage.

- Each generating unit shall be capable of absorbing reactive current up to 30% of its maximum current rating when its terminal voltage is at or above 115% of the nominal voltage and the unit is operating in reactive current priority mode.
- Each generating unit shall have the capability to inject negative-sequence reactive current up to 50% of its maximum current rating when the negative-sequence voltage at its terminal is at or above 25% of the nominal voltage and the unit is operating in reactive current priority mode.

Each generating unit shall meet the performance specifications in IEEE Std. 2800-2022, Section 7.2.2.3.5.

8.1.4 Consecutive Voltage Deviations

The facility shall be capable of riding through multiple voltage excursions driving the applicable voltage outside of the continuous operation region. The facility shall meet the ride-through capability requirements specified in IEEE Std. 2800-2022, Section 7.2.2.4.

8.1.5 Restore Output After Voltage Ride-Through

When the applicable voltage returns to the continuous operating region after a disturbance, the facility shall meet the requirements for restoring output that are specified in IEEE Std. 2800-2022, Section 7.2.2.6, with a recovery time of 1 second, except when the AESO directs otherwise.

8.2 Transient Voltage Ride-Through Requirements

The facility shall ride through transient over-voltages as specified in Table 4 as long as the cumulative durations do not exceed the minimum ride-through times specified in the table. The cumulative duration shall be calculated according to IEEE Std. 2800-2022, Section 7.2.3, using a 60 second time window.

Table 4: Transient Overvoltage Ride-Through Requirements at Point of Connection

Voltage, V (p.u.) (b)(c)	Minimum ride-through time (ms)
V > 1.80	Note (a)
V > 1.70	0.2
V > 1.60	1.0
V > 1.40	3.0
V > 1.20	15.0

Note (a): appropriate surge protection shall be applied at the point of connection as well as within the facility, including generating unit terminals as necessary.

Note (b): The base for per unitization is the nominal instantaneous peak voltage at the point of connection.

Note (c): Specified voltage magnitudes are the residual voltages with surge arresters applied.

A generating unit may operate in current blocking mode, if necessary, when the instantaneous voltage at its terminal exceeds 1.2 p.u. If operating in current blocking mode, the unit must resume current exchange within 5 cycles of the instantaneous voltage falling below, and remaining below, 1.2 p.u.

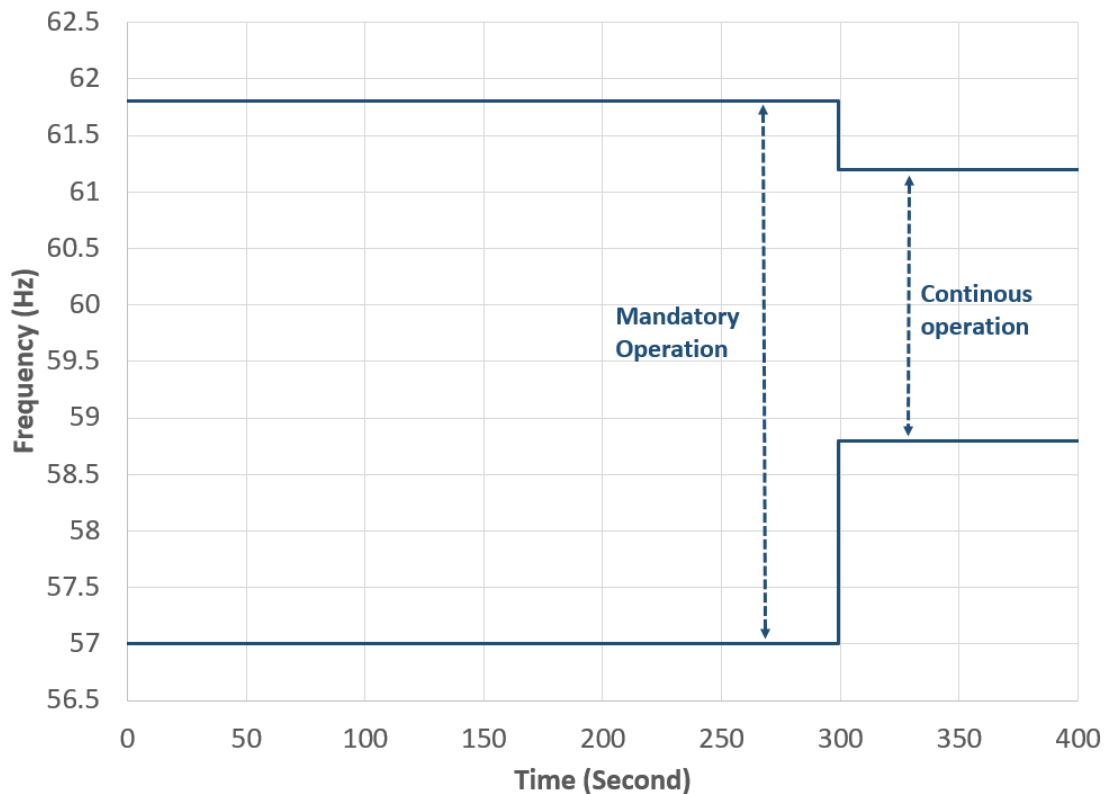
8.3 Frequency Ride-Through Requirements

The facility shall meet the frequency and rate of change of frequency (ROCOF) ride-through requirements specified in IEEE Std. 2800-2022, Sections 7.3.2.1, 7.3.2.2, and 7.3.2.3.

The frequency ride-through requirements are depicted in Figure 7.

For the purposes of the ride-through requirement in IEEE Std. 2800-2022, Section 7.3.2.3.5, ROCOF shall be the average rate of change of frequency over a 0.5 [s] averaging window.

Figure 7. Frequency Ride-Through Requirements



8.4 Voltage Phase Angle Jump Ride-Through

The facility must meet the ride-through requirements for voltage phase change specified in IEEE Std. 2800-2022, Section 7.3.2.4.

9. Power Quality

9.1 Voltage Fluctuations

9.1.1 Rapid Voltage Changes

The definitions and methods for assessment of rapid voltage changes (RVC) for the purposes of compliance with this sub-section are those specified in IEC 61000-4-30/AMD1:2021 or later. Rapid voltage changes shall be assessed at the **point of connection**.

Frequent RVC must not exceed 2.5% of the normal operating voltage when they are caused by frequent energization or switching of elements within the facility, abrupt variation in output of the facility caused by

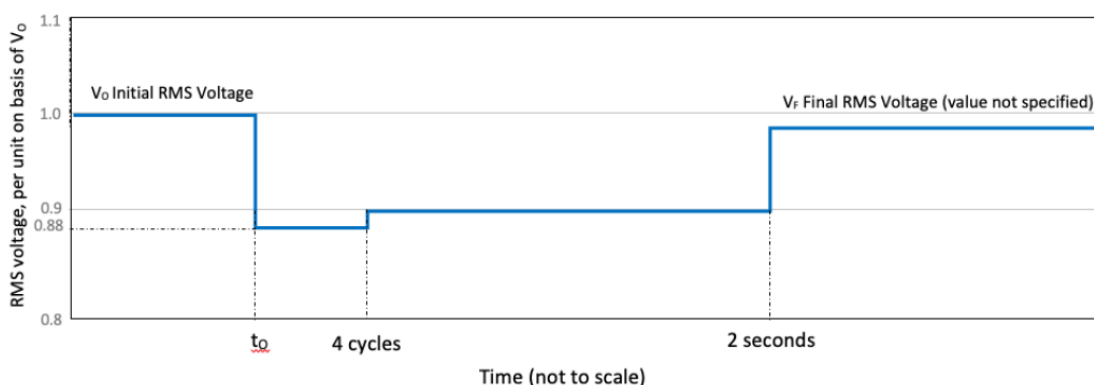
misoperation, or adverse interaction between the facility’s controls and the grid. This applies whether in normal operating conditions, or during reasonably anticipated outage conditions, such as maintenance of a single nearby transmission line segment.

For the purposes of establishing limits on infrequent RVC, let $V(t)$ be the per unit voltage at the **point of connection**, and t_0 be the time when an event causes an RVC. When an infrequent event such as switching, tripping, or energization during commissioning, fault restoration, or maintenance causes an RVC, the voltage change must meet the following constraints:

- $V(t) - V(t_0) \geq -0.12 \text{ p.u.}$ in the interval $t_0 \leq t < t_0 + \frac{4}{60} \text{ [s]}$.
- $V(t) - V(t_0) \geq -0.1 \text{ p.u.}$ in the interval $t_0 + \frac{4}{60} \text{ [s]} \leq t < 2.0 \text{ [s]}$.

The acceptable envelope is illustrated in Figure 8.

Figure 8: Voltage Envelope for Infrequent RVC



9.1.2 Flicker

The definitions and methods for measuring and assessing flicker for the purposes of compliance with this sub-section are those specified in IEC TR 61000-3-7 (Subclause 6.3) and IEEE Std. 1453 (Subclause 6.3). The facility’s contribution to flicker shall be assessed at the **point of connection**.

Table 5: Flicker Limits

Metric	Emission limit	Evaluation interval
Short term flicker, P_{st}	$E_{pst} \leq 0.35$	10 minutes
Long term flicker, P_{lt}	$E_{plt} \leq 0.25$	2 hours

For each metric listed in Table 5, the 95th percentile value among all consecutive evaluation intervals in a 1-week sliding window must not exceed the emission limit⁷.

⁷ In addition to the limit in ISO Rule 502.1 section 14(1) / 503.11.

9.2 Harmonics

The definitions and methods for measuring and assessing harmonic voltage distortion for the purposes of compliance with this sub-section are those specified in IEC 6100-4-7 Class I and IEC 6100-4-30 and IEEE Std. 519.

The target performance levels for harmonic voltage distortion, with reference to Table 6, are:

- For each day, the 99th percentile 3-second measurement is less than 1.5× the maximum value.
- For each week, the 95th percentile 10-minute measurement is less than the maximum value.

The distortion levels shall be adjusted for voltage imbalance according to IEEE Std. 2800-2022, section 8.2.1.

Table 6: Maximum Voltage Distortion

Harmonic	Maximum voltage distortion	
	POC is 138 kV or 144 kV	POC is 230 kV or 240 kV
$2 \leq h \leq 50$	1.5%	1.0%
Total harmonic distortion	2.5%	1.5%

Table 7: Maximum Current Distortion

Harmonic	Maximum current distortion (percent of rated current)	
	POC is 138 kV or 144 kV	POC is 230 kV or 240 kV
$h = 2$	1.0%	1.0%
$h = 3$	2.0%	1.5%
$h = 4$	2.0%	2.0%
$h = 5$	2.0%	1.5%
$h = 6$	3.0%	3.0%
$7 \leq h \leq 11$	2.0%	1.5%
$12 \leq h \leq 16$	1.0%	1.0%
$17 \leq h \leq 50$	1.0%	1.0%
Total rated current distortion	2.5%	2.0%

The facility owner must arrange for voltage distortion to be measured, for a period of one week,

- prior to energization of the facility;
- after energization, and when the facility is capable of real power output near to MARP; and
- after power quality mitigations are implemented, if required.

If voltage distortion at any harmonic or total harmonic distortion is materially below the target performance level before energization, and the corresponding value is materially above the target performance level after energization, then:

- The AESO will coordinate power quality mitigations between the facility owner, the TFO, and the AESO, and implement any mitigations it deems reasonable to limit harmonic current distortion.
- The facility owner must limit 95th percentile harmonic current distortion at the point of connection as specified in Table 7, with consideration given to the AESO’s mitigations, except as otherwise agreed between the facility owner and the AESO.
- The facility owner must measure the efficacy of the mitigations.

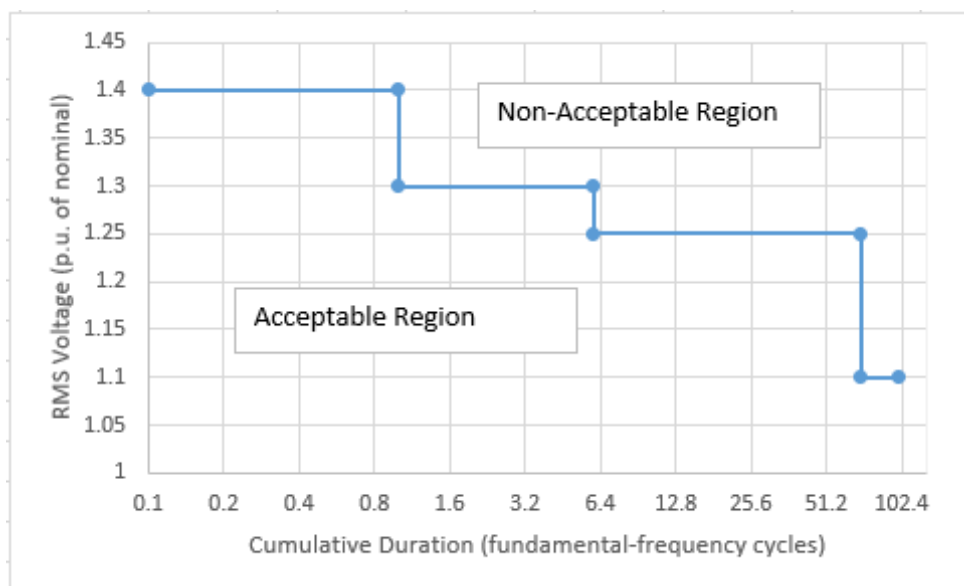
The facility owner must provide documentation of its power quality assessments to the AESO.

9.3 Limitation of Overvoltage Contribution

The facility must not:

- Cause transient over-voltages that exceed the limits for ride-through as set out in Section 8.2.
- Cause voltage excursions at the point of connection whose RMS magnitude⁸ or duration are outside the envelope specified in Figure 9.

Figure 9: RMS Overvoltage Limits for an IBR Plant at the Point of Connection



⁸ Based on a 1 cycle sliding window.

10. Protection

Protections applied to auxiliary loads and other electrical systems within the facility must not prevent the facility from meeting ride-through requirements.

10.1 Frequency and ROCOF Protection

Frequency or ROCOF protections implemented within the facility must meet the following requirements:

- Frequency or ROCOF protections that trip collector systems or main step-up transformers should only be implemented when needed to isolate equipment that has off-nominal frequency limitations.
- The protections must not prevent the facility from meeting the ride-through requirements in Section 8.3.
- The protections must use filtered quantities to reduce the probability of misoperation.

10.2 AC Voltage Protection

AC voltage protections implemented within the facility must meet the following requirements:

- The protections must not prevent the facility from meeting the ride-through requirements in Section 8.1 or Section 8.2.
- The protections must use filtered quantities to reduce the probability of misoperation.
- Instantaneous voltage protections that can interrupt the power output of the entire facility must use a measurement window that is 1 cycle or larger.
- Voltage protections must be coordinated with transmission facility protections and under-voltage load shedding as applicable.
- Voltage protections must be coordinated with the transient over-voltage capability of the facility.
- Voltage protections must be coordinated with surge protection implemented within the facility and at the point of connection.

10.3 Over-current Protection

Over-current protections implemented within the facility must meet the following requirements:

- The protections must not prevent the facility from meeting any ride-through requirements.
- The protections must use filtered quantities to reduce the probability of misoperation.
- Instantaneous over-current protections that can interrupt the power output of the entire facility must use a measurement window that is 1 cycle or larger.
- Over-current protections must be coordinated with other protection schemes employed on the transmission system as applicable.

11. Electromagnetic Transient (EMT) Model

11.1 General

The facility owner must submit an EMT model that meets the requirements listed in this specification. The model must meet the requirements listed in the draft ID #2010-001R, posted 2023-11-28.

The model must allow for accurate simulation of the facility under steady state, set-point change, and disturbance conditions for all levels of system strength and energy source availability at which the facility can operate. Linearized models that are only accurate for a single operating point are not acceptable.

11.2 Accuracy

The EMT model must:

- Represent the entire facility, including: generating unit(s); generator step-up transformers; auxiliary systems; main power transformers; dynamic reactive devices; shunt capacitors or reactors; collector system cables; and any other mechanical or electrical features relevant to the facility's interaction with the system.
- Represent all pertinent electrical and mechanical equipment and features thereof. Mechanical features (such as gearboxes, turbines with pitch control, etc.) should be modeled to the extent that they impact electrical performance. Any control or dynamic features of the actual equipment that may influence behavior in the simulation period, and are approximated or omitted, must be clearly identified as such in the documentation.
- Represent all pertinent control features as they are implemented in the real equipment, including customized PLLs, ride-through controllers, sub-synchronous control interaction (SSCI) damping controllers, etc.
- Represent the full detailed inner control loop of the power electronics for each IBR unit, as implemented in the real equipment. To a reasonably practicable extent, the submitted model shall use the same program code that is in the physical devices it represents.
- Incorporate a full IGBT representation (preferred) or use a voltage source interface that mimics IGBT switching (such as a firing-pulse-based model). A three-phase sinusoidal source representation is not acceptable.
- Represent plant-level controllers, such as automatic voltage regulation. Parameters typically requiring site-specific adjustment, such as gain and droop, should be user accessible. If multiple resources are controlled by a common controller, this functionality must be included in the plant control model. Delays such as communication or measurement delays in actual control and protections shall be accurately represented in the model.
- Include detailed representations of pertinent protections for both balanced and unbalanced fault conditions. Typically, this includes various over-voltage and under-voltage protections (individual phase and RMS), frequency protections, DC bus voltage protections, converter over-current protections, and other inverter-specific protections. Any protections that can influence dynamic behavior or plant ride-through in a 10 second simulation period must be included.
- Reasonably represent DC-side dynamics in various operating conditions, including transient behavior due to system disturbances.
- Represent the behavior of the facility across the entire real and reactive power output range.
- Reflect site-specific equipment settings. User-tunable parameters or options must be set in the model to match actual equipment settings.

All automatic changes to operating modes that occur within the facility should happen automatically within the model; and if automatic mode switchover cannot occur, then operating mode changes must be possible to simulate using configuration file or variable changes, and clearly documented. Separate models must not be required to simulate different operating modes, except when an IBR unit has both grid-forming and grid-following capability. In that case, two models may be submitted, representing the facility in each mode.

11.3 Usability

The EMT model must:

- Be accompanied by documentation of user-configurable features.
- Have hardware options, settings, and control system parameters accessible to the user, such as: protection thresholds, real power recovery ramp rates, frequency or voltage droop settings, voltage control response times, or SSCI damping controller parameters. Diagnostic flags to show control mode changes or protection activations should be visible.
- Be capable of operating at a range of simulation time steps, including time steps larger than 10 μ s.
- Have identification or versioning information. The model documentation must clearly relate settings and configurations used in studies to those used in the field (when applicable), allowing for comparison, transfer, and recording of settings during commissioning and maintenance. Compliance measures may include settings files with revision numbers.
- Be capable of self-initialization. Slower control functions, such as switched shunt controllers or power plant controllers, must accept initial condition variables when needed for self-initialization.
- Accept external reference values. This includes real and reactive power reference values (for Q control modes), or voltage reference values (for V control modes). The model must accept the reference values for initialization and respond to value changes throughout a simulation.
- Allow protections to be disabled when physically possible.

When several inverters are represented using a single model component, the component must allow scaling based on real power capacity. The scaling capability is distinct from a dispatchable power order and is used for adjusting the size of an equivalent/composite model.

11.4 Performance

The EMT model must:

- Be compiled using Intel Fortran compiler version 15 or higher.
- Be compatible with PSCAD version 4.6.3 or higher.
- Include external dependencies, except for commonly available, free redistributable libraries.
- Not use or rely upon global variables in the PSCAD environment.
- Not use multiple layers in the PSCAD environment, including 'disabled' layers.

The facility owner must provide models compatible with other programs or program versions within six months upon request from the AESO.

The EMT model should:

- Initialize reasonably quickly, based on user-provided terminal conditions.
- Support the PSCAD "snapshot" feature.
- Support the PSCAD "multiple run" feature.
- Allow replication in different PSCAD cases or libraries through the "copy" or "copy transfer" features.

Each IBR unit model should support multiple instances of its own definition in the same simulation case.

11.5 Accompanying Information

The following information must accompany the model:

- For each inverter unit, the manufacturer name, model, and version or revision number.
- For each inverter unit, the minimum SCL or SCR for which the inverter was designed, if any.
- A list and description of the computer files comprising the model.
- Instructions for setting up and using the model⁹.
- A single line diagram of the facility.
- A list of all control functions and their parameters, with descriptions, and identification of those accessible to the model user.
- A documented test case.
- A list of all AC and DC protections, with descriptions, and identification of associated settings accessible to the model user.
- Model validation, verification, and quality test reports report meeting the requirements outlined in the draft ID #2010-001R posted 2023-11-28.

11.6 Requirements for Wind Generation Facilities

The EMT model must:

- Represent machine slip of Type III (DFIG) wind generation as appropriate for the power dispatch.
- Represent any sub-synchronous oscillation (SSO) mitigation and/or protection that may exist, including the ability to enable and disable the SSO mitigation/protection, if applicable.

12. EMT Study

The facility owner must use the EMT model that will be submitted to the AESO to:

- Demonstrate the facility will follow power order commands¹⁰ and limit ramp rate when moving between levels of power output, by simulating power order step changes (such as down below potential real power, then back up).
- Demonstrate the facility will provide reactive power and regulate voltage in accordance with the applicable requirements, by simulating two voltage step changes at the point of connection, step down and step up, that are sufficiently large such that the facility responds by maximizing and minimizing its real power output, respectively, without tripping.
- Demonstrate the facility will inject incremental reactive power when voltage disturbances occur, in accordance with the applicable requirements, by simulating single-phase and three-phase faults outside the facility but near the point of the interconnection, showing real and reactive power and current, and comparing them to expected output.
- Demonstrate the facility will provide frequency regulation in accordance with the applicable requirements, by simulating at least two frequency excursions, above and below nominal with the

⁹ In the context of a single machine infinite bus (SMIB) system.

¹⁰ to the extent possible, limited by availability of the underlying energy resource.

facility limited to less than its available capacity and comparing the real power output to the frequency response performance requirement.

- Demonstrate the facility has acceptable voltage, frequency, and ROCOF ride through capabilities in accordance with the applicable requirements by simulating frequency and voltage excursions that are marginally within the bounds of the respective ride-through envelopes for single events; that do not cause the facility to trip; and which are not anticipated, in the opinion of the facility owner, to be materially damaging to the facility.
- Demonstrate the facility will ride through severe phase angle changes in accordance the applicable requirements, using a test setup where phase angle changes are simulated at the **point of connection** that are marginally within the ride-through requirement, and the facility remains connected and stable following the disturbances. At least two simulations with balanced ± 25 degree phase jumps must be performed.
- Demonstrate the facility will provide reliable performance at the point of connection for a range of available fault levels. The model shall be tested for strong and weak SCL conditions. For each test, a solid three phase to ground fault shall be simulated near the point of connection and cleared in a realistic time. The simulations shall demonstrate the facility will provide a stable and well-damped response when SCL is the minimum value specified by the AESO, or when the SCL corresponds to $SCR = 3.0$, whichever is lower; and the simulated reactive power output of the facility shall reflect proper response by the facility's voltage regulating system.

The facility owner must submit an authenticated report that is accepted by the AESO that documents the simulated scenarios and results.

The facility may not start commercial operation unless the simulations and report indicate the facility will comply with the related functional requirement(s).

13. SCADA Requirements

13.1 General Requirements

In addition to the supervisory control and data acquisition (SCADA) requirements set out in the ISO rules and ID #2012-013R, the following requirements apply:

- Sensed and derived measurements shall have no intentional time delays that would prevent a SCADA point from meeting the AESO's data latency and polling frequency requirements.
- Testing and verification of all SCADA monitoring and control points shall be completed as part of the facility commissioning process. Evidence of this testing shall be provided to the AESO as part of the project documentation.

13.2 SCADA Requirements

The SCADA points in Table 8 shall be available for the IBR facility and implemented per the ISO rules.

If the facility is operated from a remote control center and not staffed at all times, then the following remote monitoring and control functionality shall be implemented:

- Operation and monitoring of any transmission connected power transformer that has an associated on-load tap changer (OLTC), including transfer between manual and automatic operation and adjustment of the tap setting.

- Operation and monitoring of all static and dynamic reactive power resources, including voltage regulating systems, automatic voltage regulators, DVARs, STATCOMs, SVCs, capacitor banks, etc.

The facility shall be designed to be capable of accepting the following control parameters from the AESO:

- Remote selection of the voltage regulating system control mode from among the three modes indicated in Section 6.
- Any analog set-points relevant to the control modes indicated in Section 6.

For solar IBR facilities larger than 150 MW:

- SCADA points shall be provided for any metrological measurements used by systems that have direct and automatic control of the facility (including stowing systems).
- Further to the meteorological data requirements established by the ISO rules, the facility shall have ancillary meteorological stations on its periphery, spaced no more than 1500 m apart; and each station shall provide the SCADA points indicated in Table 8.

Table 8: Additional SCADA Requirements

Measurement	Signal Type	Description	Units	Accuracy	Resolution
Maximum Reactive Power Capability (Supplying)	Analog	Maximum reactive power that the facility is capable of supplying at the point of connection, considering equipment capability	MVAr	±2%	0.1
Maximum Reactive Power Capability (Absorbing)	Analog	Maximum reactive power that the facility is capable of absorbing at the point of connection, considering equipment availability	MVAr	±2%	0.1
Panel Tilt Angle	Analog	For a solar facility only with axial tracking, average angle of panel tilt for the facility for each adjustable/variable axis	Degrees	±2°	1
Panel Stowage Active	Status	For a solar facility only with axial tracking, indicates the facility is currently stowing or has the complete or partial facility panels in a stowed state.	Note (a)	N/A	N/A
FRS Status	Status	Frequency regulating system status	Note (b)	N/A	N/A
IBR Unit Status	Analog	Percentage of IBR inverters of PCS online	percent	±0.1	0.1
VRS Control Mode	Status	Voltage regulating system control mode	Note ©	N/A	N/A
VRS Voltage Setpoint	Analog	Current setting of the voltage setpoint for the VRS while in voltage control mode	kV	±0.1kV	0.1kV
VRS Reactive Power Setpoint	Analog	Current setting of the reactive power setpoint while in reactive power control mode	MVAr	±0.5MVAr	0.5MVAr
Ancillary Met – Global Horizontal Irradiance	Analog	For each ancillary met station for a solar facility	W/m ²	±25 W/m ²	1 W/m ²
Ancillary Met – Wind Speed	Analog	For each ancillary met station for a solar facility	m/s	±0.25 m/s	0.1 m/s

Measurement	Signal Type	Description	Units	Accuracy	Resolution
Ancillary Met – Wind Directions	Analog	For each ancillary met station for a solar facility	Degrees	±5°	1°
Ancillary Met – Temperature	Analog	For each ancillary met station for a solar facility	°C	±1°C	1°C

Note (a): 0 = Tracking/not stowed; 1 = Stowed.

Note (b): 0 = Disabled; 1 = Frequency droop control; other values as applicable.

Note (c): 0 = Disabled; 1 = Voltage control; 2 = Power factor control; 3 = Reactive power control; other values as applicable.

14. Event Recording

In addition to the event record and dynamic disturbance recording requirements set out in the ISO rules and Alberta Reliability Standards, the requirements in Table 9 shall apply.

Event recording data shall meet the following requirements:

- The data shall be synchronized to coordinated universal time (UTC) with a local time offset.
- Synchronized device clock accuracy within ±100 µsec of UTC.
- All collected data should follow the IEEE Standard Common Format for Transient Data Exchange (COMTRADE) or the IEEE Power Quality Data Interchange Format (PQDIF).
 - COMTRADE files shall be provided as specified in IEEE Std C37.111™-1999, IEEE Std C37.111™-2013, or later.
 - PQDIF files shall be provided as specified in IEEE Std 1159.3™-2003 or IEEE Std 1159.3™-2019, or later.

Table 9: Event and Measurement Data Requirements

Data type	Trigger	Measurement/data points	Recording rate	Retention	Duration
Sequence of events (SER) recording	Circuit breaker position on the high side of step-up transformer and each collector feeder All major and minor fault codes and alarms Change of operating mode High and low voltage ride-through High and low frequency ride-through PLL loss of synchronism Control system command values, reference values, and feedback signals	Change of status in triggering elements	N/A	1 year	N/A

Data type	Trigger	Measurement/data points	Recording rate	Retention	Duration
Power quality, long-term harmonics in COMTRADE or PQDIF format	Not applicable	Voltage and current harmonics at the point of connection, total distortion, and individual harmonics up to order 50.	95 th percentile weekly per IEEE Std. 519	1 year	N/A
Digital fault recording (DFR), COMTRADE and csv formats	Neutral (residual) current, AC phase under/over voltage on the high side of step-up transformers(s) AC phase under/over voltage, DC over voltage, DC over current, DC reverse current, over/under frequency	On the high side of step-up transformers(s): Phase-to-neutral voltage for each phase Each phase current and residual to neutral current Real and reactive power On generating units(s) connected to last 10% of each collector feeder length: Each AC phase-to-neutral or phase-phase voltage Each AC phase current and residual or neutral current DC bus current and voltage	At least 128 samples per cycle	90 days	Total length of 5 seconds with 5 cycles of pre-trigger record

15. Ramp Management and Operational Limits

The facility shall be capable of receiving a signal to ramp the facility or resource to a managed level of generation (such as for power ramp management (PRM), constraint management (CDG), or SPS purposes) from the AESO in the form of a value, in MW, indicating the maximum permissible output of the facility, which is updated as needed. The facility's output must be limited to this ramp value. When the ramp value is received, the facility must start ramping to that value automatically with no intentional delay; with a total delay not exceeding 15 seconds; and with an adjustable active power ramp rate, in MW/min, between 5% and 20% of the gross real power capability of the facility in both ramp up and ramp down directions.

The facility owner acknowledges and agrees that the AESO will apply real power output limits to the facility as it deems necessary to maintain the reliability of the AIES, including for the purposes of managing balancing, supply loss, and transmission congestion risks.

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